December 27, 2023

Mr. George Korvah

Environmental Manager

U.S. General Services Administration - Central Heating and Refrigeration Plant

325 13th Street SW

Washington, DC 20407

**RE: Permit No. 7161-R1 to Install Flue Gas Recirculation (FGR) on and Operate 250 MMBTU/hr Boiler No. 6 at the U.S. General Services Administration (GSA) Central Heating & Refrigeration Plant (CHRP)**

Dear Mr. Korvah:

Pursuant to sections 200.1 and 200.2 of Title 20 of the District of Columbia Municipal Regulations (20 DCMR), a permit from the Department of Energy and Environment (“the Department”) shall be obtained before any person can construct and operate a stationary source in the District of Columbia. The application of the U.S. General Services Administration (“GSA” or “the Permittee”) toinstall a flue gas recirculation (FGR) system on and operate Boiler No. 6, a 250 MMBTU/hr rated heat input dual-fuel boiler, at 325 13th  Street SW, Washington DC 20407, has been reviewed:

Based on the submitted plans and specifications as detailed in the application received on May 21, 2022, as revised by the application received June 26, 2023 and additional information received August 15, 2023 and November 3, 2023, the application review has been completed and the installation of the FGR system and subsequent operation of the boiler is permitted, subject to the following conditions:

1. General Requirements:
	1. This approval is issued pursuant to the applicable air pollution control requirements of 20 DCMR for the burner replacement and operation of the boiler.

b. This permit expires on December 26, 2028. If continued operation after this date is desired, the owner or operator shall submit an application for renewal by September 26, 2028. [20 DCMR 200.4]

c. Construction or operation of equipment under the authority of this permit shall be considered acceptance of its terms and conditions.

d. The Permittee shall allow authorized officials of the Department, upon presentation of identification, to:

1. Enter upon the Permittee’s premises where a source or emission unit is located, an emissions related activity is conducted, or where records required by this permit are kept;

2. Have access to and copy, at reasonable times, any records that must be kept under the terms and conditions of this permit;

3. Inspect, at reasonable times, any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit; and

4. Sample or monitor, at reasonable times, any substance or parameter for the purpose of assuring compliance with this permit or any applicable requirement.

e. This permit shall be kept on the premises and produced upon request.

f. Failure to comply with the provisions of this permit may be grounds for suspension or revocation. [20 DCMR 202.2]

g. Within four (4) months from the date of issuance of this permit, the Permittee shall submit an application (or application amendment) to include the requirements of this permit in the facility’s Chapter 3 (Title V) operating permit. [20 DCMR 301.1(a)(2) and 20 DCMR 301.1(b)(5)]

1. Emissions Limitation:
	1. Emissions from the boiler shall not exceed the following rates[[1]](#footnote-1) [20 DCMR 201]:

| **Pollutant** | **Emissions Burning Natural Gas** **(lb/hr)** | **Emissions Burning No. 2 Fuel Oil (lb/hr)** |
| --- | --- | --- |
| Oxides of Nitrogen (NOx) | 15.0 | 32.5 |
| Carbon Monoxide (CO) | 10.0 | 10.0 |
| Sulfur Dioxide (SO2) | 0.15 | 0.38 |
| Total Particulate Matter [PM Total]† | 1.25 | 5.0 |

† Includes both condensable and filterable particulate matter.

b. Total suspended particulate matter emissions from the boiler shall not be greater than 0.05 pounds per million BTU. [20 DCMR 600.1]

#### c. Oxides of nitrogen (NOx) emissions from the boiler shall not exceed:

1. When burning natural gas:

##### i. 0.05 pounds per MMBTU based on a calendar day average, on days when the equipment is powered exclusively by natural gas. [20 DCMR 805.5(e)(2)(B)]; and

##### ii. 0.2 pounds per MMBTU maximum two (2) hour average, expressed as NO2. .[20 DCMR 804.1 and 20 DCMR Chapter 8, Appendix 8-1];

##### 2. When burning No. 2 fuel oil:

##### i. 0.12 pounds per MMBTU based on a calendar day average, on days when the equipment is powered by fuel oil or a combination of fuel oil and natural gas. [20 DCMR 805.5(e)(2)(A)]; and

##### ii. 0.3 pounds per MMBTU maximum two (2) hour average, expressed as NO2. [20 DCMR 804.1 and 20 DCMR Chapter 8, Appendix 8-1];

d. Visible emissions shall not, at any time, exhibit opacity more than ten percent (10%) (unaveraged) from the unit except that discharges shall be permitted for two (2) minutes during any startup, cleaning, adjustment of combustion or operational controls, or regeneration of emission control equipment, provided that such discharges shall not exceed the following opacities [20DCMR 606.1(a)(3) and 20 DCMR 606.2]:

1. When burning exclusively natural gas, twenty percent (20%); and

2. When burning fuel oil or a combination of fuel oil and natural gas, twenty-seven percent (27%).

e. NOx and CO emissions from the boiler shall not exceed those achieved with the performance of annual combustion adjustments on the boiler, performed per Conditions III(e) and (f). [20 DCMR 805.5(b) and 20 DCMR 805.9]

f. An emission into the atmosphere of odorous or other air pollutants from any source in any quantity and of any characteristic, and duration which is, or is likely to be injurious to the public health or welfare, or which interferes with the reasonable enjoyment of life or property is prohibited. [20 DCMR 903.1]

Violation of the requirements of this condition that occur as a result of unavoidable malfunction, despite the conscientious employment of control practices, shall be an affirmative defense for which the owner or operator shall bear the burden of proof. A malfunction shall not be considered unavoidable if the owner or operator could have taken, but did not take, appropriate steps to eliminate the malfunction within a reasonable time, as determined by the Department. [20 DCMR 903.13(b)]

*Note: This condition is District enforceable only.*

g. Facility-wide emissions of NOx from the Central Heating and Refrigeration Plant shall not exceed 268 tons in any 12-consecutive-month period. [20 DCMR 201 and 20 DCMR 805.2][[2]](#footnote-2) For purposes of determining compliance with this condition, NOx emissions shall be determined as follows:

* + 1. For all temporary and permanently-installed boilers and the combined heat and power (CHP) system (also known as Combustion Turbines 1 and 2 and Boiler 5), emissions shall be determined based on the results of monitoring using properly certified Continuous Emissions Monitoring Systems (CEMS) for NOx, except that another method may be specified for units that may be installed after the date of this permit, as authorized by District and federal laws and regulations; and
		2. Emissions from all emergency engines shall be determined based on manufacturer-specified emission factors and assuming the maximum horsepower of the engine for the period of operation during each 12-consecutive-month period, unless other unit-specific factors are developed based on emissions testing, in which case, these factors may be used in lieu of the manufacturer-specified factors, upon approval of the Department.

h. In addition to the above emission limitations, the Permittee shall comply with all plant-wide emission limits found in Chapter 3 (Title V) Permit No. 032.

III. Operational Limitations:

* 1. The Permittee shall comply with the following fuel limitations:
		1. Natural gas shall be the only fuel burned in Boiler No. 6 except when natural gas service is interrupted by the supplier;
		2. The Permittee shall burn only natural gas with a maximum hydrogen sulfide (H2S) content of one grain per one hundred standard cubic feet (1 gr/100 SCF) and a maximum total sulfur content of twenty grains per hundred standard cubic feet (20 gr/100 SCF);
		3. The sole back-up fuel for the boiler shall be No. 2 fuel oil that meets the following requirements [20 DCMR 201 and 20 DCMR 801]:

i. No fuel oil shall be purchased for use in the boiler that contains more than fifteen parts per million (15 ppm) or fifteen ten-thousandths percent (0.0015%) by weight of sulfur, except as specified in Conditions III(a)(3)(ii) and (iii);

ii. When EPA temporarily suspends or increases the applicable limit or percentage by weight of sulfur content of fuel required or regulated by EPA by granting a waiver in accordance with Clean Air Act § 211(c)(4)(C) provisions, the federal waiver shall apply to corresponding limits for fuel oil in the District as set forth in Condition III(a)(3)(i); and

iii. If a temporary increase in the applicable limit of sulfur content is granted under Condition III(a)(3)(ii), the suspension or increase in the applicable limit will be granted for the duration determined by EPA and the sulfur content may not exceed 500 ppm by weight.

* 1. The consumption of No. 2 fuel oil from the entire facility (CHRP) shall be limited to 4,435,035 gallons of fuel oil per year. [20 DCMR 201, 20 DCMR 805.2, 40 CFR 52.470(d), and Title V Permit No. 032, Condition B(a)]
	2. The Permittee shall not operate the boiler for more than eleven months per calendar year. A shutdown period of at least one month per calendar year shall occur during a thirty-consecutive-day period between April 1 and November 1 of any given year. [20 DCMR 201, 40 CFR 52.470(d), and Title V Permit No. 032, Condition B(i)]
	3. At all times, including periods of startup, shutdown, and malfunction, the Permittee shall maintain and operate the unit, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operating and maintenance procedures are being used will be based on information available to the Department that may include, but is not limited to, monitoring results, opacity observations, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source. [20 DCMR 201, 20 DCMR 606.4(a), and 40 CFR 63.7500(a)(3)]

e. The Permittee shall perform tune-ups on the boiler annually, by November 1st of each year, and not to exceed 13 months from the date of the last tune-up, except as specified in Condition III(f)(6). Such tune-ups shall be performed for each fuel burned during the 12 months prior to the tune-up, except that if the only instance of burning a fuel was due to testing or tuning performed pursuant to the requirements of this permit, tuning on that fuel will not be required that year. The Permittee shall perform tune-ups on the unit as specified in Condition III(f). [40 CFR 63.7540(a)(10) and 20 DCMR 805] *Note that this is a streamlined permit condition. Both 20 DCMR 805 and 40 CFR 63.7540(a)(10) require annual tune-ups, but 20 DCMR 805 requires tuning on both fuels while* *40 CFR 63.7540(a)(10) only requires tuning while burning the type of fuel (or fuels in case of a mixture) that provided the majority of the heat input to the boiler over the 12 months prior to the tune-up. As such, tuning on both fuels is required as specified.*

f. In order to demonstrate continuous compliance, the tune-up shall be performed to meet the following criteria: [40 CFR 63.7540(a)(10)(i) through (v) and 20 DCMR 805.9] *Note that these requirements are streamlined to incorporate the most stringent and specific conditions of both regulatory requirements.*

1. As applicable, inspect the burner, and clean or replace any components of the burner as necessary for proper operation (the Permittee may perform the burner inspection at any time prior to the tune-up or delay the burner inspection until the next scheduled unit shutdown). At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment;

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;

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);

4. Optimize total emissions of NOx, and to the extent possible, CO. This optimization should be consistent with the manufacturer's specifications, if available, and shall be consistent with any NOx and CO requirements to which the unit is subject; and

5. Measure the concentrations in the effluent stream of CO and NOx in parts per million, by volume, dry basis (ppmvd) and oxygen in percent by volume dry basis, before and after the adjustments are made. Measurements may be taken using a portable analyzer.

g. The Permittee shall maintain the equipment in accordance with one of the following [20 DCMR 606.4(b)]:

1. The manufacturer’s emission-related written instructions; or

2. Unless preempted by specific federal regulation, an alternate written maintenance plan approved in writing by the Department.

h. The Permittee shall ensure that persons participating in the maintenance and operation of equipment are adequately trained and supervised to meet the requirements of Conditions III(d) and III(g). [20 DCMR 606.4(c)]

IV. Monitoring and Testing:

a. The Permittee shall calibrate, maintain certification of and operate CEMS for measuring emissions of oxides of nitrogen (NOx) and either carbon dioxide (CO2) or oxygen (O2) discharged into the atmosphere, and record the output of the system in accordance with 40 CFR 60.48b(b)(1) and as follows: [20 DCMR 501.1, 20 DCMR 805.5(f)(2), and 20 DCMR 805.10(a)(1)]

1. The CEMS must meet Performance Specifications 2 and 3 in Appendix B of 40 CFR 60.

2. The Permittee shall follow the requirements of 40 CFR 60.48b(e) and (f) for the installation, evaluation, and operation of the NOx CEMS.

3. The Permittee must certify and operate the installed continuous NOx and either CO2 or O2 emissions monitoring system and perform quality assurance procedures outlined in 40 CFR 60, Appendix F to maintain certification of the CEMS.

4. The CEMS shall continuously monitor and record the NOx emission rate from the boiler.

5. The CEMS shall be installed and operated in a manner approved aby the Department and acceptable to EPA.

6. The Permittee shall configure the monitoring system to document compliance or non-compliance, as applicable, with the NOx limitations found in Conditions II(a) and (c).

b. The Permittee shall maintain certification of and operate a continuous opacity monitoring system (COMS) for measuring the opacity of the emissions discharged to the atmosphere in accordance with Performance Specification 1 in Appendix B of 40 CFR 60. These COMS shall be programmed to determine compliance with respect to Condition II(d). [20 DCMR 501.1 and 502.10, and 20 DCMR 606]

c. At a minimum, the Permittee shall perform the following procedures for the CEMS and COMS to ensure proper operation and calibration: [20 DCMR 502.10, 40 CFR 51 Appendix P, and 40 CFR 60 Appendix F]

1. The COMS unit shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 10-second period.

2. The CEMS units for measuring oxides of nitrogen and either CO2 or O2, shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

3. The Permittee shall install the CEMS and COMS units such that representative measurements of emissions or process parameters from affected facilities are obtained.

4. At least once per day, the Permittee shall perform a zero and span check on the COMS units and determine the calibration drift on the CEMS unit and adjust the units appropriately.

5. The Permittee shall adjust the zero and span whenever the 24-hour zero drift or 24-hour calibration drift limits of the applicable performance specifications in Appendix B of 40 CFR Part 60 are exceeded, or whenever the 24-hour zero drift or 24-hour calibration drift exceed 10 percent of the emissions standard.

6. The Permittee shall ensure that COMS unit’s span is approximately 200 percent of the expected instrument data display and output corresponding to the emission standard for the source.

d. The Permittee shall develop and implement a quality control program for the COMS and CEMS units that details procedures for the following, at a minimum: [40 CFR 60 Appendix F]

1. Calibration of the COMS and CEMS units;

2. Calibration drift determination and appropriate adjustment of the COMS and CEMS units.

3. Preventative maintenance of the COMS and CEMS units (including spare parts inventory);

4. Data recording, calculations, and reporting;

5. Accuracy audit procedures, including sampling and analysis methods; and

6. Program of corrective action in the case of malfunctions.

e. The CEMS units shall be audited at least once per calendar quarter in accordance with the procedures detailed in 40 CFR 60 Appendix F, Section 5. Successive quarterly audits shall occur no closer than 2 months. [40 CFR 60 Appendix F]

1. In three of the four calendar quarters, a Cylinder Gas Audit (CGA) may be conducted in accordance with the procedures in Appendix F of 40 CFR 60 Section 5.1.2. A CGA shall not be conducted for more than three consecutive quarters.

2. A Relative Accuracy Test Audit (RATA) shall be conducted at least once every four calendar quarters in accordance with Appendix B of 40 CFR 60 and applicable sampling methods.

f. To show compliance with Condition III(a)(3), the Permittee shall sample and test the fuel oil burned in its fuel burning equipment at least once each calendar quarter or at the time of each fuel delivery, whichever is less frequent. For each sample, the Permittee must provide [20 DCMR 502]:

1. The fuel oil type and the ASTM method used to determine the type (see the definition of distillate oil in 40 CFR 60.41c for appropriate ASTM methods);

2. The weight percent sulfur of the fuel oil as determined using ASTM test method D-4294 or D-5453 or other method approved in advance by the Department;

3. The date and time the sample was taken;

4. The name, address, and telephone number of the laboratory that analyzed the

 sample; and

5. The type of test or test method performed.

In lieu of sampling and testing fuel oil each quarter for each of these data, the Permittee may obtain any or all of these data from the fuel oil supplier at the time of delivery and submit fuel receipts and fuel supplier certifications for all fuel deliveries that provide all of the above quality of fuel data (or those for which sampling and testing was not performed at the time of delivery) as well as the name of the fuel oil supplier, the date of delivery, and the sulfur content of the oil.

Note that the sulfur content data obtained from the fuel supplier must be the results of specific tests of the fuel at hand or the most recent representative fuel analysis from the fuel terminal prior to the fuel supplier obtaining the fuel for delivery to the Permittee, if such terminal analyses are performed on at least a monthly basis. General fuel specifications are not acceptable for this datum.

Terminal specifications (with references to appropriate ASTM methods as defined above) may be used to document the fuel oil type if the fuel supplier provides written certification that this was the material purchased from the terminal and delivered to the facility. If this method of determining the fuel oil type is used, the Department may opt to require occasional supplemental sampling and testing of the fuel oil to confirm these certifications.

If any of these data cannot be obtained from the fuel supplier, it is the responsibility of the Permittee to sample the fuel and have it analyzed to obtain the required data.

g. Within twelve (12) months of the issuance of this permit, and at least once every five (5) years thereafter, the Permittee shall conduct performance tests on the boiler to determine compliance with Conditions II(a) (except NOx and SO2) and (b) and shall furnish the Department with a written report of the results of such performance test in accordance with the following requirements [20 DCMR 502 and 40 CFR 60]:

1. One (1) original test protocol shall be submitted to air.quality@dc.gov a minimum of thirty (30) days in advance of the proposed test date. The test shall be conducted in accordance with federal and District requirements.

2. The test protocol and test date(s) shall be approved by the Department prior to initiating any testing. The Department must have the opportunity to observe the test for the results to be considered for acceptance.

3. The final results of the testing shall be submitted to the Department within sixty (60) days of the test completion. One (1) original copy and one electronic copy of the test report shall be submitted to the following addresses:

Chief, Compliance and Enforcement Branch

Department of Energy and Environment

Air Quality Division

1200 First Street NE, 5th Floor

Washington DC 20002

and

air.quality@dc.gov

4. The final report of the results shall include the emissions test report (including raw data from the test) as well as a summary of the test results and a statement of compliance or non-compliance with permit conditions to be considered valid. The summary of results and statement of compliance or non-compliance shall contain the following information:

i. A statement that the owner or operator has reviewed the report from the emissions testing firm and agrees with the findings.

ii. Permit number(s) and condition(s) which are the basis for the compliance evaluation.

iii. Summary of results with respect to each permit condition.

iv. Statement of compliance or non-compliance with each permit condition.

5. The results must demonstrate to the Department’s satisfaction that the emission unit is operating in compliance with the applicable regulations and conditions of this permit; if the final report of the test results shows non-compliance the owner or operator shall propose corrective action(s). Failure to demonstrate compliance through the test may result in enforcement action.

h. CHRP must have a one-time energy assessment performed by a qualified energy assessor. An energy assessment completed on or after January 1, 2008, that meets or is amended to meet the energy assessment requirement in this permit condition, satisfies the energy assessment requirement. The energy assessment must include the following with extent of the evaluation for items i to v appropriate for the on-site technical hours listed in Condition IV(i) [40 CFR 63.7540 and 40 CFR 63, Subpart DDDD, Table 3]

i. A visual inspection of the boiler systems;

ii. An evaluation of operating characteristics of the boiler systems, specifications of energy using systems, operating and maintenance procedures, and unusual operating constraints;

iii. An inventory of major energy use systems consuming energy from affected boilers;

iv. A review of available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage;

v. A review of the facility’s energy management program and provide recommendations for improvements consistent with the definition of energy management program (see 40 CFR 63.7575), if identified;

vi. A list of cost-effective energy conservation measures that are within the facility’s control;

vi. A list of the energy savings potential of the energy conservation measures identified; and

vii. A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.

i. The energy assessment for CHRP (a facility with a combined heat input capacity greater than 1.0 trillion BTU/year) (TBTUyr) will be up to 24 on-site technical labor hours for the first TBTU/yr plus 8 on-site technical labor hours for every additional 1.0 TBTU/yr not to exceed 160 on-site technical hours, but may be longer at the discretion of the Permittee. The boiler systems and any on-site energy use systems accounting for at least 20 percent of the energy (e.g., steam, process heat, hot water, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities. [40 CFR 63.7575, definition of “Energy assessment”.

V. Record Keeping and Reporting Requirements:

a. All records and related support information required pursuant to Condition V of this permit shall be maintained at the facility for a period of five (5) years from the date of the monitoring sample, measurement, report or application, and shall be made available to the Department and the U.S. Environmental Protection Agency upon request and as specified in the reporting requirements below. Support information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by the permit. Records may be kept in electronic formats as long as such records can be certified as to their accuracy and validity. [20 DCMR 302.1(c)(2)(B), 20 DCMR 500.8, 20 DCMR 606.5(d), and 20 DCMR 805.11] *Note that this is a streamlined condition requiring that the records be maintained for the longest period required by the cited regulatory sections.*

b. Except when being submitted as part of a submittal required by the facility’s Title V permit (in which case the requirements of the Title V permit shall be followed), or if the Permittee is directed by the Department to submit the reports to separate data system, such as CEDRI, or if otherwise specified in a particular condition below, reports required by this permit shall be submitted to the following addresses, as applicable:

Reports to EPA:

United States Environmental Protection Agency

Region III, Enforcement & Compliance Assurance Division

Air, RCRA and Toxics Branch (3ED21)

Four Penn Center

1600 John F. Kennedy Boulevard

Philadelphia PA 19103-2852

Reports to the Department:

air.quality@dc.gov

c. The Permittee shall keep records of the NOx and either O2 or CO2, as applicable, CEMS data for all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments. [20 DCMR 500.2 and 20 DCMR 805.11]

d. 1-hour average NOx emission rates measured by the continuous NOx monitor consistent with the procedures in 40 CFR 60.13(h) shall be expressed in lb/MMBTU heat input and shall be used to calculate the average emission rates to document the compliance status with respect to Condition II(c). The 1-hour averages shall be calculated using the data points required under 40 CFR 60.13(h)(2). [20 DCMR 500.2, based on 40 CFR 60.48b(d)]

e. The Permittee shall maintain all records of opacity measurements obtained with the use of the required continuous opacity monitoring system (COMS) required pursuant to Condition IV(b).

f. The Permittee shall record the zero and span drift of the CEMS and COMS units in accordance with the methods prescribed by the instrument manufacturers. [20 DCMR 502.10, 40 CFR 51 Appendix P]

g. The Permittee shall submit quarterly reports of CEMS data, including NOx, gas diluent [i.e., O2 or CO2], COMS opacity measurements, and CEMS audits pursuant to Condition IV(e). The reports shall adhere to the reporting requirements found in the document titled: Data Reporting Requirements for Continuous Emission Monitors (CEMS), dated September 24, 1996 (as amended), which is hereby incorporated by reference. [20 DCMR 302.1(c)(3)(A) and 40 CFR 60 Appendix F, Section 7]

h. The Permittee shall maintain records of fuel information obtained pursuant to Condition IV(f).

i. The Permittee shall maintain all records of the results of all emissions testing obtained pursuant to the requirements of Condition IV(g) of this permit.

j. The Permittee shall maintain records of the amounts of each fuel combusted during each day and calculate the annual capacity factor, as defined in 40 CFR 60.41b, individually for distillate oil and natural gas for each reporting period. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month. [40 CFR 60.49b(d)(1)] The fuel usage data collected and recorded shall also be maintained in a 12-month rolling sum format and used to document compliance with Condition III(b).

k. The Permittee shall maintain records of the following information regarding operations of the unit and shall submit reports of these data as part of the quarterly CEMS reports due pursuant to Condition V(f) [20 DCMR 500.1 and 500.2, based on 40 CFR 60.49b(g)]:

1. Calendar date of operation;

2. The average hourly NOx emission rates (expressed as NO2) (lb/MMBTU heat input) measured or predicted;

3. Identification of the steam generating unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken;

4. Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data;

5. Identification of any “F” factor used for calculations, method of determination, and type of fuel combusted;

6. Identification of the times when the pollutant concentration exceeded full span of the CEMS;

7. Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3 (40 CFR 60, Appendix B); and

8. Results of daily CEMS drift tests and quarterly accuracy assessments as required under 40 CFR 60, Appendix F, Procedure 1.

l. The Permittee shall submit semiannual excess emission reports for any excess emissions of NOx that occurred during the reporting period. [20 DCMR 500.1] Excess emission reports shall be submitted to coincide with the semi-annual reports required by the facility’s Chapter 3 (Title V) operating permit.

m. The Permittee shall maintain onsite and submit, if requested by the EPA Administrator or the Department, a biennial report containing the information in paragraphs V(l)(1) through (3) of this section. [40 CFR 63.7540(a)(10)(vi)]

1. The concentrations of CO in the effluent stream in parts per million, by volume, and oxygen in volume percent, measured before and after the tune-up of the boiler.

2. A description of any corrective actions taken as a part of the tune-up of the boiler.

3. The type and amount of each fuel used over the 12 months prior to the biennial tune-up of the boiler.

n. Whenever the Permittee uses No. 2 fuel oil in the boiler due to a period of natural gas curtailment or supply interruption as defined in 40 CFR 63.7575, the Permittee shall submit to EPA and the Department a notification of alternative fuel use within 48 hours of the declaration of each period of natural gas curtailment or supply interruption as defined in 40 CFR 63.7575. The notification must include the following information [40 CFR 63.7545(f)]:

1. Company name and address;

2. Identification of the affected boiler;

3. Reason the Permittee is unable to use natural gas, including the date when the natural gas curtailment was declared or the natural gas supply interruption began;

4. Identification of the alternative fuel the Permittee intends to use; and

5. Dates when the alternative fuel use is expected to begin and end.

o. If not already submitted by the date of this permit, the Permittee shall immediately submit a “Notification of Compliance Status” with respect to 40 CFR 63, Subpart DDDDD to include the following information [40 CFR 63.7545(e)]: *Note that this notification was due within 60 days of the compliance date specified at 40 CFR 63.7495(b), January 31, 2016.*

1. A description of the affected unit(s) including identification of which subcategories the unit is in, the design heat input capacity of the uint, a description of the add-on controls used on the unit to comply with 40 CFR 63, Subpart DDDDD, description of the fuel(s) burned, including whether the fuel(s) were a secondary material determined by the Permittee or EPA through a petition process to be a non-waste under 40 CFR 241.3, and whether the fuel(s) were a secondary material processed from discarded non-hazardous secondary materials within the meaning of 40 CFR 241.3; and

2. In addition to the information required in 40 CFR 63.9(h)(2), the notification of compliance status must include the following certification(s) of compliance, as applicable, and signed by a responsible official:

A. “This facility completed the required initial tune-up for all for all of the boilers and process heaters covered by 40 CFR part 63 subpart DDDDD at this site according to the procedures in § 63.7540(a)(10)(i) through (vi).”; and

B. “This facility has had an energy assessment performed according to § 63.7530(e).”

p. Unless the EPA Administrator has approved a different schedule for submission of reports under 40 CFR 63.10(a), the Permittee must submit annual reports related to the requirements of 40 CFR 63, Subpart DDDDD according to the following [40 CFR 63.7550(b)]:

1. The Permittee must submit all reports required by Conditions V(p)(2) and (3) [see 40 CFR 63.7550(c)(1)-(5)] electronically to EPA via the CEDRI. (CEDRI can be accessed through EPA’s CDX.) The Permittee must use the appropriate electronic report in CEDRI for 40 CFR 63, Subpart DDDDD. Instead of using the electronic report in CEDRI for 40 CFR 63, Subpart DDDDD, the Permittee may submit an alternate electronic file consistent with the XML schema listed on the CEDRI website ([*http://www.epa.gov/ttn/chief/cedri/index.html*](http://www.epa.gov/ttn/chief/cedri/index.html)), once the XML schema is available. If the reporting form specific to 40 CFR 63, Subpart DDDDD is not available in CEDRI at the time that the report is due, the Permittee must submit the report to the EPA Administrator at the appropriate address listed in 40 CFR 63.13. The Permittee must begin submitting reports via CEDRI no later than 90 days after the form becomes available in CEDRI.

2. The schedule for reporting shall be as follows:

A. The first annual compliance report for Boiler 6 must cover the period beginning on January 31, 2016 [see 40 CFR 63.7495(b)] and ends on December 31, 2016.

B. The first annual compliance report must be postmarked or submitted no later than January 31, 2017.

C. Each subsequent annual compliance report must cover the period from January 1 through December 31 for each subsequent year.

D. Each subsequent annual compliance report must be postmarked or submitted no later than January 31 following the end of the annual reporting period.

3. Each compliance report must contain the following information:

A. Company and Facility name and address;

B. Process unit information, emissions limitations, and operating parameter limitations;

C. Date of report and beginning and ending dates of the reporting period;

D. The date of the most recent annual tune-up for the unit. Include the date of the most recent burner inspection if it was not done annually and was delayed until the next scheduled or unscheduled unit shutdown; and

E. Statement by a responsible official with that official’s name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report.

q. The Permittee must keep a copy of each notification and report that was submitted to comply with Conditions V(o) and (p) of this permit, including all documentation supporting any Initial Notification or Notification of Compliance Status or annual compliance report that was submitted. [40 CFR 63.7555(a)(1)]

r. If the unit is operated on No. 2 fuel oil at any time, the Permittee must keep records of the total hours per calendar year that the No. 2 fuel oil is burned and the total hours per calendar year that the unit operated during periods of gas curtailment or gas supply emergencies. [40 CFR 63.7555(h)]

s. In addition to those record keeping and reporting requirements specified in Condition V(m), the Permittee shall maintain, in a permanently bound log book or another format approved in writing by the Department, the following information to document compliance with the requirements of Conditions II(e) and III(e) and (f) as follows [20 DCMR 500.1, 20 DCMR 805.9(c), and 40 CFR 63.7540(a)(10)]:

* + 1. The date on which the combustion process was last tuned-up;
		2. The name, title, and affiliation of the person who performed the tune-up;
		3. The NOx concentrations in the effluent stream, in ppmvd, measured at high fire or typical operating load, before and after the tune-up;
		4. The CO concentrations in the effluent stream, in ppmvd, measured at high fire or typical operating load, before and after the tune-up;
		5. The CO2 concentrations in the effluent stream, in percent by volume dry basis, measured at high fire or typical operating load, before and after the tune-up;
		6. The O2 concentrations in the effluent stream, in percent by volume dry basis, measured at high fire or typical operating load, before and after the tune-up;
		7. A description of any corrective actions taken as a part of the tune-up of the unit;
		8. 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, except that units sharing a fuel meter may estimate the fuel use by each unit; and
		9. Any other information that the Department may require.

t. The Permittee must keep records of the occurrence and duration of each malfunction of Boiler No. 6, or of any associated air pollution control and monitoring equipment. [40 CFR 63.7540 and 20 DCMR 500.1]

u. The Permittee shall: [20 DCMR 606.5]

* + 1. Maintain signed or electronically verified logs of the date, time, and duration of any equipment manual startup, manual shutdown, cleaning, combustion control adjustment, emission control regeneration, and malfunction;
		2. For any malfunction, investigate the cause of the malfunction and maintain records of the investigatory activities and conclusions of such investigation; and
		3. Maintain signed or electronically verified logs of the date and description of any maintenance performed on any installed COMS.

If you have any questions, please call me at (202) 535-1747 or Abraham T. Hagos at (202) 535-1354.

Sincerely,

Stephen S. Ours, P.E.

 Chief, Permitting Branch

SSO:ATH

1. For purposes of this condition, NOx emissions shall be determined on a one-hour average based on CEMS monitoring. CO and PM Total shall be determined in accordance with the emissions testing procedures specified in Condition IV(g), and SO2 emissions shall be determined based on the fuel sulfur content obtained pursuant to Condition IV(f). [↑](#footnote-ref-1)
2. An equivalent to this limit was originally established in a Chapter 2 permit, issued October 21, 1997, to avoid applicability of 20 DCMR 204, and was subsequently included in Title V permit No. 032, Condition B(f), issued July 28, 2000. It is now also being adopted as a part of an Alternative RACT plan pursuant to 20 DCMR 805.2. [↑](#footnote-ref-2)