MEMORANDUM

TO: Amy S. Mann, P.E. ASM

THROUGH: Olayiwola I. Okesola, P.E. O.O.

FROM: Eric S. Rowland ESR

SUBJECT: **Croda Inc.**
Atlas Point
Draft Permit: APC-2023/0052-CONSTRUCTION (GACT) (NSPS) (MNSR) (FE)
110 MMBtu Boiler (Boiler 6)

DATE: October 20, 2023

BACKGROUND INFORMATION

Croda Inc. (Croda, the Company, or the Facility) requested a Construction Permit for the installation of a 110 MMBtu boiler (90,000 pound per hour of steam) to be identified as Boiler 6 in an application dated January 13, 2023, and updates emailed on May 31, 2023 and June 9, 2023. Boiler 6 will replace the 1940s era Boiler 3. Boiler 6 will be fired on No. 2 fuel oil, natural gas, and a natural gas/landfill gas blend.

Croda Inc. manufactures chemical products and surfactants in various reactors, kettles, autoclaves, and other vessels. The Facility currently operates under a Title V permit, **Permit: APC-003/00058-Renewal (03)-Revision (07)**, dated April 19, 2023, and is a major source of NO_X and CO_2. In addition, the Facility was previously subject to a Plantwide Applicability Limit (PAL) for NO_X of 54 TPY via **Permit: APC-2012/0120-OPERATION(PAL)(FE)** issued June 25, 2012. This PAL permit was not renewed, and Croda is in the process of preparing a request to cancel the permit and spread the allowed emissions amongst the covered emission units. The emission units at the Atlas Point Facility are listed in Table 1.

Table 1: Atlas Point Emission Units

Emission Unit (EU) # or Designation	Emission Unit Description
EU 108	Boiler No. 5 – 84 MMBtu heat input, fired on landfill gas, natural gas, and No. 2 fuel oil
EU 105	Temporary Boiler – fired on natural gas and No. 2 fuel oil
EU 3 EU 4	Blend Tank Area – two blend tanks, vented to the atmosphere
EU 13	3A and 4 Autoclave Hotwell – vented to atmosphere
EU 14	3A and 4 Autoclave Deodorizer Hotwell – vented to atmosphere
EU 15	4 Kettle Fume Spray Condenser – 22 scfm
EU 16	5 Autoclave Scrubber (Croll Reynolds) – 45 gpm, 14 scfm
EU 18	5 Autoclave Fume & Dust Scrubber (Croll Reynolds) – 15 gpm, 835 scfm
EU 19	5 Autoclave Deodorizer Hotwell – vented to atmosphere
EU 20	7 Kettle Spray Condenser – 105 gpm, 2100 scfm
EU 23	EO/PO Storage Area Scrubber (Croll Reynolds) – 1 gpm, 100 scfm
EU 26	6 Autoclave Scrubber (Croll Reynolds)- 38 gpm, 106 scfm
EU 31 EU 32 EU 33 EU 34	Unloading Station Tanks

Emission Unit (EU) # or Designation	Emission Unit Description
EU 35	
MP1EU 1	Multipurpose Plant R-3100 Reactor Condenser (Yula) – 140 °F vent discharge
MP1EU 2	Multipurpose Plant R-3200 Reactor Condenser Vent (Rubicon Industries) – 140 °F vent discharge
MP1EU 3	Multipurpose Plant R-3300 Reactor Condenser Vent (Rubicon Industries) – 100 °F vent discharge
MP1EU 4	Multipurpose Plant R-3400 Reactor Condenser Vent (Rubicon Industries) – 140 °F vent discharge
MP1INV 15	Multipurpose Plant Solid Mix Tank – vented to atmosphere
MP1INV 18 MP1INV 19 MP1INV 20	Multipurpose Plant Vacuum Pumps – vented to atmosphere
MP1EU 21	Laminar Flow Booth – vented to atmosphere
28-7000 28-7001 28-7002 28-7004 28-7010 28-7011 28-7013 28-7015 28-7016 18-7067	Tank Farm
INV270 INV271 INV272 INV273	No. 2 Fuel Oil Fired Emergency Generators – INV270: Main Guardhouse, INV271: Flammable Warehouse, INV272: IT Generator, & INV273: EO/PO
EU 106 EU 107	Two 1100 KW landfill gas fired distributed generators
EU 504	Ethanol Dehydration Furnace, 12.47 MMBtu, fired on natural gas and landfill gas
EU 505	Carbonate Regenerator, process CO_2 recovery unit
CD 505	Catalytic Combustion Unit, 0.81 MMBtu, fired on natural gas
EU 506	Ethylene Oxide Storage Tank, 30,000 gallons
EU 507	Ethylene Oxide Storage Tank, 30,000 gallons
CD 506	Scrubber, ethylene oxide emissions from storage tanks
EU 508	Ethyl Chloride Chemical Addition Pot
T-1290	Ethylene Purification Column (start-up and extended shutdown)
	300 kW Emergency Generator, fired on No. 2 fuel oil
	Two (2) 350 HP Fire Pumps 1 & 2, one (1) existing 235 HP Fire Pump, all fired on No. 2 fuel oil
	Lab Hoods
D-1410A	Ethanol Storage Tank #1, vertical fixed roof, 50,000 gallons
D-1410B	Ethanol Storage Tank #2, vertical fixed roof, 50,000 gallons
F-1203	Ethanol Blowdown Tank, vertical fixed roof, 10,000 gallons

Emission Unit (EU) # or Designation	Emission Unit Description
G-336	Anti-foam Tank
F-615	Crude Ethylene Glycol Tank, 5,000 gallons
D-620A D-620B	Two (2) Glycol Product Receiver Tanks
D-630	Heavy Glycol Tank
F-1261	Propylene Glycol Tank, 200 gallons
F-1430	Propylene Glycol Tank, 1,000 gallons
F-651	MEG Product Storage Tank
	2.108 MW Combined Heat and Power Distributed Generator
	99.9 MMBtu Limited Term Boiler

The facility is subject to the requirements of §112(r) of the 1990 Clean Air Act Amendments. The facility has registered in compliance with 7 DE Admin. Code 1201 "Accidental Release Prevention Regulation." Title VI requirements 40 CFR, Part 82, Subparts A, E, F, and G (labeling and recordkeeping for products using ozone-depleting substances) are applicable.

Facility wide PTE is shown in Table 2.

Table 2: Facility Potential to Emit (PTE)[1]

Pollutant	Facility Wide PTE (tons/year)	Major Source Threshold (tons/year)
Nitrogen Oxides (NO_X)	109.4	25
Volatile Organic Compounds (VOCs)	31.8	25
Carbon Monoxide (CO)	48.1	100
Particulate Matter (PM)	9.6	100
Particulate Matter Less Than 10 Microns (PM_{10})	9.6	100
Particulate Matter Less Than 2.5 Microns ($PM_{2.5}$)		25
Sulfur Dioxide (SO_2)	20.7	100
Lead	n/a	10
Carbon Dioxide Equivalent (CO_2e)	115,153	100,000
Other (EO)	1.2	10
Other (PO)	0.6	10

[1] – Facility PTE based off PTE table provided by Croda dated April 16, 2020.

The facility is a major source for nitrogen oxides (NO_X) and carbon dioxide equivalent (CO_2e). They have requested limits and are a synthetic minor source for volatile organic compounds (VOC) and hazardous air pollutants (HAPs). The permit will be advertised for 30 days and will be incorporated into the Title V permit pursuant to the requirements of 7 DE Admin. Code 1102 Section 12.4.

The Company has not requested confidentiality.

The Company is located within the Coastal Zone. The project has been evaluated by DNREC's Division of Climate, Coastal and Energy (CCE), and found to fall under the category of "Uses Not Regulated" as CCE considers this a replacement in-kind.

The Company is current with their annual fees and has paid appropriate construction application fees.

The property is zoned HI (Heavy Industry). The Company has brought this project to the attention of New Castle County's (NCC) Department of Land Use in application number 2022-03003-A. NCC has determined that the boiler itself does not trigger the need for a Special Use Permit, however, that the building enclosing the boiler would trigger the need for such a permit. A Special Use Permit for the construction of a 2,410 square foot mechanical building to house the boiler was issued on July 11, 2022.

The Facility is located in a Limited English neighborhood. The legal notice will be translated to Spanish. The facility is located near an Equity Focus area. Enhanced outreach regarding the permitting action will be conducted by the Facility.

The following correspondence has taken place between the Company and the Department in regard to Boiler 6. Dates given are document or email dates and dates in parenthesis (where applicable) are receipt dates.

Date	From	To	Document
04-19-22	Company	DNREC	Draft AERMOD Report
05-09-22	Company	DNREC	Draft BACT Analysis
05-18-22	DNREC	Company	Draft BACT Analysis – DAQ Response
06-07-22	DNREC	Company	Draft AERMOD Report – DAQ Response
06-14-22	Company	DNREC	Draft BACT Analysis – Second Draft
07-07-22	DNREC	Company	Draft BACT Analysis – Second Draft – DAQ Response
07-26-22	Company	DNREC	Draft BACT Analysis – Third Draft
07-29-22 (08-02-22)	Company	DNREC	Draft AERMOD Report – Second Draft
09-21-22	DNREC	Company	Draft BACT Analysis – Third Draft – DAQ Response
10-03-22	Company	DNREC	Draft Boiler 6 Application
01-13-23 (01-18-23)	Company	DNREC	Boiler 6 Application
04-13-23	DNREC	Company	Email – Boiler 6 NSPS/NESHAP Items
04-20-23	DNREC	Company	Email – Boiler 6 NSPS/NESHAP Items – Clarification of CEMS versus monitor
04-20-23	DNREC	Company	Email – Boiler 6 AQM-5 Discussion
05-31-23	Company	DNREC	Email – Boiler 6 AQM-5 Discussion – Company Response
06-02-23	DNREC	Company	Email – Boiler 6 AQM-5 Discussion – Further Questions
06-05-23	Company	DNREC	Email – Boiler 6 AQM-5 Discussion – Further Questions – Company Response
06-08-23	DNREC	Company	Email – Boiler 6 AQM-5 Discussion – Further Questions 2
06-08-23	DNREC	Company	Email - Question regarding NG-LFG ratio.
06-09-23	Company	DNREC	Email – Boiler 6 AQM-5 Discussion – Further Questions 2 – Company Response

Date	From	To	Document
06-13-23	Company	DNREC	Email – Question regarding NG-LFG ratio – Company Response
06-28-23	Company	DNREC	Email – NSPS Exemption Request
06-30-23	DNREC	Company	Email – NSPS Exemption Request – DAQ Response with Interpretation – Work on the permit is stopped until Croda determines path forward
07-07-23	Company	DNREC	Phone – NSPS Exemption Request – Questions Regarding Interpretation
07-13-23	DNREC	Company	Email – NSPS Exemption Request – DAQ Response
07-31-23	Company	DNREC	Email – NSPS Exemption Request – Croda has decided not to pursue exemption and will install the NO_X CEMS – Work on the permit resumes

TECHNICAL INFORMATION

The 110 MMBtu boiler (Boiler 6) can be fired on No. 2 fuel oil, natural gas, and a natural gas/landfill gas blend. The boiler will be equipped with ultra-low NO_X burners, flue gas recirculation, and a carbon monoxide oxidation catalyst.

Potential to Emit / Permitted Emissions

The potential to emit (PTE) was calculated based on the emissions factors provided to the Division of Air Quality (DAQ) in the application dated January 13, 2023, as well as from the Environmental Protection Agency's (EPA) AP-42 Compilation of Air Emission Factors. The PTE was calculated for each fuel type expected to be fired. These are shown in Figures 3, 4 and 5 below.

Table 3: Boiler 6 Potential to Emit (PTE)
Fired on No. 2 Fuel Oil

Pollutant	Emission Factor	EF Units	EF Source	Emission Rate (lb/hr)	Uncontrolled PTE (TPY)	Controlled PTE (TPY)
NO_X	24	lb/1000 gal	1	18.9	83	48
CO	0.10	lb/MMBtu	2	11	48	29
SO_X	0.22	lb/1000 gal	1	0.17	0.76	0.76
PM (TPM or PT)	2	lb/1000 gal	1	2	7	7
TOC	0.556	lb/1000 gal	3	0.437	1.91	1.91

Emission Factor (EF) Source
1 – AP-42, Table 1.3-1
2 – Manufacturer Data
3 – AP-42, Table 1.3-3

Table 4: Boiler 6 Potential to Emit (PTE)
Fired on Natural Gas

Pollutant	Emission Factor	EF Units	EF Source	Emission Rate (lb/hr)	Uncontrolled PTE (TPY)	Controlled PTE (TPY)
NO_X	190	lb/MMSCF	1	20.5	90	5.2
CO	0.037	lb/MMBtu	2	4.1	18	1.8
SO_X	0.6	lb/MMSCF	3	0.06	0.3	0.3
PM (TPM or PT)	7.6	lb/MMSCF	3	0.82	3.6	3.6
TOC	11	lb/MMSCF	3	1.2	5.2	5.2

Emission Factor (EF) Source
1 – AP-42, Table 1.4-1
2 – Manufacturer Data
3 – AP-42, Table 1.4-2

Table 5: Boiler 6 Potential to Emit (PTE)
Fired on Natural Gas / Landfill Gas Blend (10%/90%)

Pollutant	Emission Factor	LFG EF Units	EF Source	Emission Rate (lb/hr)	Uncontrolled PTE (TPY)	Controlled PTE (TPY)
NO_X	633	lb/MMSCF	1	120.3	577.1	16.3
CO	0.037	lb/MMBtu	2	4.1	17.8	1.8
SO_X	1.22	lb/hr	3	1.10	4.8	4.8
PM (TPM or PT)	0.69	lb/hr	4	0.69	3.0	3.0
VOC/TOC	0.24	lb/hr	5	0.33	1.4	1.4

Emission Factor (EF) Source
1 – Prorated AP-42 EF for NG based on performance guarantee for NG/LFG from manufacturer
2 – Manufacturer Data
3 – Calculated based on 35 ppm H2S in LFG supply converted to SO2
4 – Permit Limit
5 – Prorated for a larger boiler (Boiler 6) based on Boiler 5 (110 MMBtu/hr vs 88 MMBtu/hr)

If the 110 MMBtu Boiler were to be run for on No. 2 fuel oil for a significant period of time, the PTE value for NO_X shown in Table 3 shows it would be a Major Source, even with controls in place. To avoid this, the Company has opted to take an enforceable limit on hours of operation, limiting the time fired on fuel oil to 1,475 hours per rolling 12-month period. The PTE, taking this enforceable limit into account, is shown in Table 6.

Table 6: Boiler 6 Potential to Emit (PTE) fired on No. 2 Fuel Oil
(1,475 hours per 12-month rolling period)

Pollutant	Emission Factor	EF Units	EF Source	Emission Rate (lb/hr)	Uncontrolled PTE (TPY)	Controlled PTE (TPY)
NO_X	24	lb/1000 gal	1	18.9	14	8.1
CO	0.10	lb/MMBtu	2	11	8.1	4.9
SO_X	0.22	lb/1000 gal	1	0.17	0.13	0.13

PM (TPM or PT)	2	lb/1000 gal	1	2	1	1.2
TOC	0.556	lb/1000 gal	3	0.44	0.32	0.32

Emission Factor (EF) Source
1 – AP-42, Table 1.3-1
2 – Manufacturer Data
3 – AP-42, Table 1.3-3

Now that the PTE for each fuel has been determined, the PTE for the Boiler 6, regardless of fuel, should be calculated. This PTE will take into account the highest emission rate(s) for each pollutant.

For NO_X, the highest emission rate is for firing fuel oil, therefore it will need to be evaluated for this rate at 1,475 hours, and then 7,285 at the next highest emission rate, which is NG/LFG.

$$\left(11\ \frac{lb}{hr} * 1{,}475\ hrs\right) + \left(3.72\ \frac{lb}{hr} * 7{,}285\ hrs\right) = 21.67\ \frac{ton}{yr}$$

For CO, the highest emission rate is for firing fuel oil, therefore it will need to be evaluated for this rate at 1,475 hours, and then 7,285 at the next highest emission rate, which is NG/LFG.

$$\left(6.6\ \frac{lb}{hr} * 1{,}475\ hrs\right) + \left(0.407\ \frac{lb}{hr} * 7{,}285\ hrs\right) = 6.35\ \frac{ton}{yr}$$

For SO_X, the highest emission rate is for landfill gas, and so the PTE for NG/LFG will be used.

For PM, the highest emission rate is for firing fuel oil, therefore it will need to be evaluated for this rate at 1,475 hours, and then 7,285 at the next highest emission rate, which is natural gas.

$$\left(2\ \frac{lb}{hr} * 1{,}475\ hrs\right) + \left(0.82\ \frac{lb}{hr} * 7{,}285\ hrs\right) = 4.46\ \frac{ton}{yr}$$

For PM_{10} and $PM_{2.5}$, emission factors were not given with the application. For firing fuel oil, the emission factors from AP-42, Table 1.3-6 were used. For firing natural gas, the emission factors from AP-42, Table 1.4-2 were used. For the NG/LFG blend, no emission factors were available, and so as a worst-case scenario the applicant supplied value for PM was used (i.e. $PM=PM_{10}=PM_{2.5}$). The highest emission rates are for natural gas, and so the PTE values for natural gas will be used.

For TOC/VOC, the highest emission rates are for natural gas, and so the PTE values for natural gas will be used.

For CO_2, emission factors were not given with the application. For firing fuel oil, the emission factors from AP-42, Table 1.3-12 were used. For firing natural gas, the emission factors from AP-42, Table 1.4-2 were used. No emission factors for the NG/LFG blend were provided. The CO_2 contained in the LFG is exempt from CO_2e calculations. However, the default CO_2 emissions factors given in 40 CFR Part 98 Subpart C Table C-1 show that LPG and propane values are typically slightly higher than LFG, and therefore natural gas could be taken as a worst case. The highest emission rate is for firing fuel oil, therefore it will need to be evaluated for this rate at 1,475 hours, and then 7,285 at the next highest emission rate, which is natural gas.

$$\left(17{,}521.4\ \frac{lb}{hr} * 1{,}475\ hrs\right) + \left(12{,}941.2\ \frac{lb}{hr} * 7{,}285\ hrs\right) = 60{,}060.4\ \frac{ton}{yr}$$

For Methane, emission factors were not given with the application. For firing fuel oil, the emission factors from AP-42, Table 1.3-3 were used. For firing natural gas, the emission factors from AP-42, Table 1.4-2 were used. No emission factors for the NG/LFG blend were available. The highest available emission rate is for natural gas, and so the PTE values for natural gas will be used.

$$\left(0.248\ \frac{lb}{hr} * 8{,}760\ hrs\right) = 1.09\ \frac{ton}{yr}$$

For N_2O, emission factors were not given with the application. Only emission factors for firing natural gas were available in AP-42, Table 1.4-2 and so the PTE values for natural gas will be used.

$$\left(0.069\ \frac{lb}{hr} * 8{,}760\ hrs\right) = 0.30\ \frac{ton}{yr}$$

Calculation of the CO_2e then proceeds as follows:

$$PTE(CO_2e) = 60{,}060.4\ \frac{ton}{yr} + \left(1.09\ \frac{ton}{yr} * 25\right) + \left(0.30\ \frac{ton}{yr} * 298\right) = 60{,}177.1\ \frac{ton}{yr}$$

Table 7: Boiler 6 Overall Potential to Emit (PTE) & Applicant Requested Limits (All Values tons/year)

Pollutant	Calculated PTE	Emissions Requested In Application	Emissions Listed In Revised AQM-5	Permitted Emissions
NO_X	21.67	16.3	21.7	21.7
CO	6.35	4.9	6.4	6.4
SO_X	4.8	4.8	4.8	4.8
PM (TPM or PT)	4.46	3.6	4.1	4.1
PM_{10}	3.59			3.6
$PM_{2.5}$	3.59			3.6
VOC	2.60			2.6
TOC	5.20	5.2	5.2	5.2
CO_2e	60,177.1			60,177.1

The AQM-5 form received with the application was found to contain errors that might cause concerns for Croda if Boiler 6 was ever fired on No. 2 fuel oil for the full requested 1,475 hours per year. The requested permitted emissions, in some cases, were based on the No. 2 fuel oil emissions calculations at 1,475 hours, and therefore would have been exceeded if any other use had occurred.

This was brought to the Company's attention in a conversation (on-site) on April 19, 2023, and followed up in an email on April 20, 2023. The Company responded with an updated AQM-5 form on May 31, 2023. On June 2, 2023, it was brought to the Company's attention again that the PM value seemed low in comparison to the Department's calculations, and a response was received on June 5, 2023, stating that the Company had reviewed the PM value and had modified it from the original 3.6 tpy in the application to

3.7 tpy in the revised AQM-5. A third revision of this AQM-5 form was received on June 9, 2023, increasing the requested emissions for PM to 4.1 tpy. Table 7 shows the values that will be used for legal notice and permitting purposes.

New Source Review (NSR) / Prevention of Significant Deterioration (PSD)

An NSR/PSD applicability determination was conducted for all non-exempt physical changes and/or changes in the method of operation. Given the option for 3 fuel types, the Potential to Emit in this case needed to be evaluated individually on each pollutant, based on the emission rates estimated above. Calculations were shown in the previous section, and these results are compared to the NSR/PSD Significance Levels in Table 8 below.

Table 8: Boiler 6 NSR/PSD Applicability Determination
Baseline Period: 2023

Pollutant	Baseline Actual Emissions (tons/yr)	Post-Change PTE (tons/yr)	Emissions Increase (tons/yr)	Significance Level (tons/yr)	Significant Increase? (Yes / No)
NO_X	0	21.67	21.67	25	No
VOC	0	2.60	2.60	25	No
CO	0	6.35	6.35	100	No
SO_X	0	4.8	4.8	40	No
PM (TPM or PT)	0	4.46	4.46	25	No
PM_{10}	0	3.59	3.59	15	No
$PM_{2.5}$	0	3.59	3.59	10	No
Lead	n/a	n/a	n/a	0.6	n/a
CO_2e	0	60,177.1	60,177.1	75,000	No

Table 8 shows that Boiler 6 alone does not trigger NSR or PSD.

Netting Discussion

The contemporaneous time period is 2019 to 2023. Projects in this period include:

- Addition of 110 MMBtu Boiler (Boiler 6)
  - Emissions taken from calculations in this memo
- Addition of Two (2) 650 hp Fire Pumps
  - Emissions taken from calculations in memo esr23008.docx
- Removal of 75 MMBtu Boiler (Boiler 3)
  - Emissions taken from Croda PTE Summary, Revision 8, dated April 16, 2022
- Addition of 90 MMBtu Boiler (Limited Term Boiler)
  - Emissions taken from calculations in memo esr21071.docx
- Removal of Spray Tower
  - Emissions taken from Croda PTE Summary, Revision 8, dated April 16, 2022
- Addition of 2.1 MW Combined Heat & Power Generator (CHP 3)
  - Emissions taken from calculations in memo mas19041.doc

The baseline period for actual emissions was based on the 2019 Annual Air Emission Inventory and Emissions Statement Report.

Calculation of the Baseline CO_2e is as follows:

$$PTE(CO_2e) = 37{,}453.8\ \frac{ton}{yr} + \left(2.46\ \frac{ton}{yr} * 25\right) + \left(0.06\ \frac{ton}{yr} * 298\right) = 37{,}533.2\ \frac{ton}{yr}$$

Calculation of CO_2e for the Limited Term Boiler is as follows:

$$PTE(CO_2e) = 51{,}731.5\ \frac{ton}{yr} + \left(0.23\ \frac{ton}{yr} * 25\right) + \left(0.64\ \frac{ton}{yr} * 298\right) = 51{,}928.0\ \frac{ton}{yr}$$

Table 9: NSR/PSD Applicability Netting Analysis
Baseline Period: 2019
(All values in TPY)

	NO_X	VOC	CO	SO_X	PM	PM_{10}	$PM_{2.5}$	CO_2e
Baseline	22.15	8.30	14.87	0.48	1.38	1.38	0.83	37,533.2
Boiler 6	21.67	2.60	6.35	4.8	4.46	3.59	3.59	60,177.1
Fire Pumps	1.88	0.043	0.59	0.67	0.06	0.06	0.06	377
Boiler 3	-47.0	-1.8	-0.6	-0.2	-2.4	-2.4	-2.4	-38,647.1
LT Boiler	15.8	1.8	16.4	0.26	2.2	2.2	2.2	51,928.0
Spray Tower		-0.2			-2.5	-2.5	-2.5	
CHP 3	3.95	5.79	2.77	0.28	2.26	2.26	2.26	14,548
Summed Changes	-3.7	8.23	25.51	5.81	4.08	3.21	3.21	88,383
Significance Level	25	25	100	40	25	15	10	75,000
Significant?	No	No	No	No	No	No	No	Yes
PTE After Changes	18.45	16.53	40.38	6.29	5.46	4.59	4.04	125,916.2

The major source threshold under the PSD permitting program is a potential to emit (PTE) of greater than or equal to 100 TPY of any criteria pollutant for which the area is in attainment of the National Ambient Air Quality Standards (NAAQS). While the evaluation of the 110 MMBtu Boiler did not exceed the threshold of any criteria pollutant, the evaluation of the 5-year contemporaneous look-back required by Delaware's dual source definition did show that the 75,000 TPY significance level and the 100,000 TPY major source threshold for CO_2e would be exceeded, triggering PSD for this pollutant. 7 DE Admin. Code 1125 Section 3.2 does not provide increment levels for CO_2e, so modeling could not be conducted. As a result, PSD is satisfied by applying Best Available Control Technology (BACT) which for CO_2e is maintaining good combustion control.

New Castle County is in non-attainment for the ozone NAAQS. The pollutants that could trigger NSR are NO_X and VOC as ozone precursors. The net emissions increases for NO_X and VOCs (including changes made during the contemporaneous period) shown in the table above do not trigger NSR for these pollutants.

Significant Impact Levels (SILs) & AERSCREEN Modeling

The effects of air contaminant emissions from the operation of the Boiler 6 on the public health, safety, and welfare were assessed using Department criteria. The criteria assume no adverse effect when the Maximum Downwind Concentration (MDC) is less than the significant impact level (SIL) for each air contaminant emitted and over each applicable averaging period. For reference the SIL is "the level of ambient impact below which the EPA considers a source to have an insignificant effect on ambient air quality." The current pollutant-specific SILs along with their respective averaging periods are summarized in Table 10 below.

Table 10: Significant Impact Levels for Pollutants of Interest

Pollutant	Averaging Time	Source	Significant Impact Level ($\mu g/m^3$)
CO	1-hour	1	2,000
	8-hour	1	500
NO_2	1-hour	2	7.5
	Annual	1	1.0
SO_2	1-hour	3	7.9
	3-hour	1	25
	24-hour	1	5
	Annual	1	1.0
PM_{10}	24-hour	1	5.0
	Annual	1	1.0
$PM_{2.5}$	24-hour	1	1.2
	Annual	1	0.3
Air Toxics	8-hour	4	TLV/100

1 – 40 CFR 51.165(b)(2)
2 – https://www.epa.gov/sites/production/files/2015-07/documents/appwno2.pdf
3 – https://www.epa.gov/sites/default/files/2015-07/documents/appwso2.pdf
4 – DNREC DAQ Internal Criteria

According to the EPA's 2018 Guidance on SILs, the EPA believes there is a valid analytical and legal basis in most cases for the permitting authority to conclude that the proposed source will not cause or contribute to a violation of a National Ambient Air Quality Standard (NAAQS) only after a permit applicant has shown through air quality modeling that the projected air quality impact from a proposed source for a particular pollutant is not significant or meaningful. In order to show that the proposed source will not have a significant or meaningful impact on air quality, the Department has elected to use these SIL values as a compliance demonstration tool.

In the case where a pollutant-specific SIL was not available, TLVs for pollutants were obtained from the *2020 TLVs and BEIs* publication from the American Conference of Governmental Industrial Hygienists (ACGIH). When compared against TLVs, the MDC must be at a level no greater than 100 times less than the published TLV in order to demonstrate that public health and safety is protected.

According to the December 19, 1980 letter by EPA's Administrator Douglas Costle to Senator Jennings Randolph:

> *"…the exemption from ambient air is available only for the atmosphere over land owned or controlled by the source and to which public access is precluded by a fence or other physical barriers."*

The Division of Air Quality's Model Application Guidance document includes the following interpretation:

> *"Based on this definition, if general public access is effectively precluded by a fence or other physical barriers, the facility is assumed to be controlled and public access effectively precluded, and the ambient air boundary can be set at where the fence line or other physical barriers are located."*

(See also the December 2, 2019, *Revised Policy on Exclusions from "Ambient Air"* by Andrew Wheeler, EPA Administrator.)

In each case, the MDC of the air contaminant is computed using AERSCREEN air dispersion modeling. AERSCREEN is EPA's recommended screening-level air quality model based on AERMOD.

AERSCREEN is an interactive command-prompt application that interfaces with MAKEMET for generating the meteorological matrix, but also interfaces with AERMAP and BPIPPRM to automate the processing of terrain and building information, and interfaces with the AERMOD model utilizing the SCREEN option to perform the modeling runs. The AERSCREEN program also includes averaging time factors for worst-case 3-hr, 8-hr, 24-hr and annual averages.

In utilizing AERSCREEN, Boiler 6 is treated as a point source. Point source variables in AERSCREEN are air contaminant emission rates (in lb/hr), stack height (in ft), stack inside diameter (in inches), stack gas exit velocity (in ft/s) or air flow rate (in acfm), plume exit temperature (in ˚F), and the urban/rural land use options. As variables such as plume exit temperature (in ˚F) and stack air flow rate (ACFM) vary depending on the fuel fired, each fuel has been evaluated separately. The variables used are shown in the Table 11 below.

Table 11: AERSCREEN Point Source Variables for Boiler 6

Parameter	Fired on No. 2 Fuel Oil	Fired on Natural Gas	Fired on NG/LFG Blend
Emission Rate (lb/hr)[1]	1	1	1
Stack Height (ft)	85	85	85
Stack Inner Diameter (in)[2]	42.48	42.48	42.48
Stack Direction	Vertical	Vertical	Vertical
Stack Cap	No	No	No
Plume Exit Temperature (˚F)	273	290	284
Stack Air Flow Rate (ACFM)	29,528	32,579	34,077
Land Use	Rural	Rural	Rural
Population Estimate	n/a	n/a	n/a
Minimum Distance to Ambient (ft)[3]	54	54	54
$MDC_{1\text{-}hr}$ ($\mu g/m^3$):	1.781	1.604	1.590

Parameter	Fired on No. 2 Fuel Oil	Fired on Natural Gas	Fired on NG/LFG Blend
$MDC_{3\text{-}hr}$ (µg/m^3):	1.781	1.604	1.590
$MDC_{8\text{-}hr}$ (µg/m^3):	1.603	1.443	1.431
$MDC_{24\text{-}hr}$ (µg/m^3):	1.068	0.9622	0.9538
MDC_{Annual} (µg/m^3):	0.1781	0.1604	0.1590

[1] – AERSCREEN was run at an emission rate of 1 lb/hr, and this result used to compute a value for each contaminant.

Using the MDC values computed for 1 lb/hr, the MDC values for each pollutant were computed and compared to the applicable Significant Impact Level (SIL). The results for the Boiler 6 fired on No. 2 Fuel oil are shown in Table 12, the results when fired on Natural Gas are shown in Table 13, and the results when fired on Natural Gas/Landfill Gas Blend are shown in Table 14.

Table 12: Comparison of Calculated MDC Values versus Significant Impact Levels For Boiler 6 Fired on No. 2 Fuel Oil

Pollutant	Emission Rate (lb/hr)	Averaging Period	MDC (µg/m^3)[1]	SIL (µg/m^3)	MDC<SIL?
CO	6.6[2]	1-hour	11.8	2,000	Yes
		8-hour	10.6	500	Yes
NO_X	11.0[2]	1-hour	19.6	7.5	No
		Annual	2.0	1	No
SO_2	0.17	1-Hour	0.3	7.8	Yes
		3-Hour	0.3	25	Yes
		24-Hour	0.2	5	Yes
		Annual	0.03	1	Yes
PM_{10}	2	24-Hour	2.1	5	Yes
$PM_{2.5}$	2	24-Hour	2.1	1.2	No
		Annual	0.4	0.2	No

[1] – Sample Calculation: (MDC @ 1 lb/hr) * (Emission Rate)
[2] – Values used are based on controlled emissions

Table 13: Comparison of Calculated MDC Values versus Significant Impact Levels For Boiler 6 Fired on Natural Gas

Pollutant	Emission Rate (lb/hr)	Averaging Period	MDC (µg/m^3)[1]	SIL (µg/m^3)	MDC<SIL?
CO	0.407[2]	1-hour	0.7	2,000	Yes
		8-hour	0.6	500	Yes
NO_X	1.21[2]	1-hour	1.9	7.5	Yes
		Annual	0.2	1	Yes
SO_2	0.065	1-Hour	0.1	7.8	Yes
		3-Hour	0.1	25	Yes
		24-Hour	0.06	5	Yes
		Annual	0.01	1	Yes
PM_{10}	0.820	24-Hour	0.8	5	Yes

Pollutant	Emission Rate (lb/hr)	Averaging Period	MDC (μg/m³)[1]	SIL (μg/m³)	MDC<SIL?
$PM_{2.5}$	0.820	24-Hour	0.8	1.2	Yes
		Annual	0.1	0.2	Yes

[1] – Sample Calculation: (MDC @ 1 lb/hr) * (Emission Rate)
[2] – Values used are based on controlled emissions

Table 14: Comparison of Calculated MDC Values versus Significant Impact Levels For Boiler 6 Fired on NG/LFG Blend

Pollutant	Emission Rate (lb/hr)	Averaging Period	MDC (μg/m³)[1]	SIL (μg/m³)	MDC<SIL?
CO	0.411[2]	1-hour	0.7	2,000	Yes
		8-hour	0.6	500	Yes
NO_X	3.721[2]	1-hour	5.9	7.5	Yes
		Annual	0.6	1	Yes
SO_2	1.096	1-Hour	1.7	7.8	Yes
		3-Hour	1.7	25	Yes
		24-Hour	1.0	5	Yes
		Annual	0.2	1	Yes
PM_{10}	0.685	24-Hour	0.7	5	Yes
$PM_{2.5}$	0.685	24-Hour	0.7	1.2	Yes
		Annual	0.1	0.2	Yes

[1] – Sample Calculation: (MDC @ 1 lb/hr) * (Emission Rate)
[2] – Values used are based on controlled emissions

The calculated MDC values for operation on natural gas, and the natural gas/landfill gas blend are all below the SIL values, and no further review is necessary. For operation on oil, the calculated values for CO, SO_2, and PM_{10} were below the SIL values, and no further review is necessary. However, for NO_X and $PM_{2.5}$ an assessment needs to be performed to determine if the calculated MDCs, when added to background concentrations, exceed the NAAQS standards for these pollutants. The results of these assessments are shown in Table 15.

Table 15: Comparison of Calculated MDC & Background Values versus NAAQS Values For Boiler 6 fired on No. 2 Fuel Oil

Pollutant	Averaging Period	MDC (μg/m³)	Background Concentration (μg/m³)	MDC + Background (μg/m³)	NAAQS (μg/m³)	Total < NAAQS?
NO_X	1-hour	19.6	66	85.6	188	Yes
	Annual	2.0	10.3	12.3	99.6	Yes
$PM_{2.5}$	24-Hour	2.1	19.0	21.1	35	Yes
	Annual	0.4	7.8	8.2	12	Yes

The comparisons show that these NO_X and $PM_{2.5}$ values, when added to the background values, do not exceed the NAAQS limits. This is interesting since early work by the Company regarding Boiler 6 suggested that the boiler would not pass AERSCREEN modeling, and therefore AERMOD modeling was performed. Upon reviewing drafts of this work, the Department requested that the AERMOD modeling also take into account the cumulative impact of the other emissions units in the immediate vicinity, specifically Boiler 5, CHP 1, CHP 2, and CHP 3.

The "Air Dispersion Modeling Report for Boiler 6", prepared for the Company by Montrose Environmental and included in the application packet, was reviewed. The report considers the contributions from Boiler 5, Boiler 6, CHP 1, CHP 2, and CHP 3 as requested. The model utilizes inputs and assumptions that the Division of Air Quality considers appropriate for the location and sources modeled.

The report considers the following operating scenarios:

- Scenario 1
  Boilers 5 and 6 operating at 100% load on 90% LFG / 10% NG
  CHP 1, 2 & 3 operating at 100% load on LFG

- Scenario 2
  Boilers 5 and 6 operating at 100% load on NG only
  CHP 1, 2 & 3 operating at 100% load on LFG

- Scenario 3
  Boilers 5 and 6 operating at 100% load on No. 2 Fuel Oil only
  CHP 1, 2 & 3 operating at 100% load on LFG

The Company evaluated 3 operating scenarios, and the modeled concentrations, when added to the appropriate background concentrations, were below the NAAQS values. Summaries of the emissions compared to the NAAQS values for each operating scenario are shown in Tables 16, 17 and 18.

Table 16: Modeled Emissions Compared to NAAQS Values for Scenario 1
Boilers 5 and 6 operating at 100% load on 90% LFG / 10% NG
CHP 1, 2 & 3 operating at 100% load on LFG

Pollutant	Model Rank	Averaging Period	Modeled Concentrations (μg/m^3)	Background Concentration (μg/m^3)	Total Impacts (μg/m^3)	Does Site Exceed NAAQS?	NAAQS (μg/m^3)	% of NAAQS
PM_{10}	H6H	24-Hour	4.31	41	45.31	No	150	30%
$PM_{2.5}$	H8H	24-Hour	2.50	32.9	35*	No	35	100%
	H1H	Annual	0.34	8.8	9.14	No	12	76%
SO_2	H4H	1-Hour	47.10	22	69.10	No	196	35%
	H2H	3-Hour	45.69	2.7	48.39	No	1,300	4%
CO	H2H	1-Hour	448.05	1.9	449.95	No	40,000	1%
	H2H	8-Hour	325.62	1.5	327.12	No	10,000	3%
NO_2	H8H	1-Hour	113.64	66	179.64	No	188	96%
	H1H	Annual	4.68	10.3	14.98	No	100	15%

* - EPA rounding rule, see note 6 in https://www.epa.gov/pm-pollution/timeline-particulate-matter-pm-national-ambient-air-quality-standards-naaqs

Table 17: Modeled Emissions Compared to NAAQS Values for Scenario 2
Boilers 5 and 6 operating at 100% load on NG only
CHP 1, 2 & 3 operating at 100% load on LFG

Pollutant	Model Rank	Averaging Period	Modeled Concentrations ($\mu g/m^3$)	Background Concentration ($\mu g/m^3$)	Total Impacts ($\mu g/m^3$)	Does Site Exceed NAAQS?	NAAQS ($\mu g/m^3$)	% of NAAQS
PM_{10}	H6H	24-Hour	4.41	41	45.41	No	150	30%
$PM_{2.5}$	H8H	24-Hour	2.54	32.9	35*	No	35	100%
	H1H	Annual	0.35	8.8	9.15	No	12	76%
SO_2	H4H	1-Hour	47.73	22	69.73	No	196	36%
	H2H	3-Hour	46.77	2.7	49.47	No	1,300	4%
CO	H2H	1-Hour	448.11	1.9	450.01	No	40,000	1%
	H2H	8-Hour	326.38	1.5	327.88	No	10,000	3%
NO_2	H8H	1-Hour	113.66	66	179.66	No	188	96%
	H1H	Annual	4.69	10.3	14.99	No	100	15%

* - EPA rounding rule, see note 6 in https://www.epa.gov/pm-pollution/timeline-particulate-matter-pm-national-ambient-air-quality-standards-naaqs

Table 18: Modeled Emissions Compared to NAAQS Values for Scenario 3
Boilers 5 and 6 operating at 100% load on No. 2 Fuel Oil only
CHP 1, 2 & 3 operating at 100% load on LFG

Pollutant	Model Rank	Averaging Period	Modeled Concentrations ($\mu g/m^3$)	Background Concentration ($\mu g/m^3$)	Total Impacts ($\mu g/m^3$)	Does Site Exceed NAAQS?	NAAQS ($\mu g/m^3$)	% of NAAQS
PM_{10}	H6H	24-Hour	3.25	41	44.25	No	150	29%
$PM_{2.5}$	H8H	24-Hour	2.17	32.9	35*	No	35	99%
	H1H	Annual	0.36	8.8	9.16	No	12	76%
SO_2	H4H	1-Hour	43.11	22	65.11	No	196	33%
	H2H	3-Hour	39.79	2.7	42.49	No	1,300	3%
CO	H2H	1-Hour	451.64	1.9	453.54	No	40,000	1%
	H2H	8-Hour	331.42	1.5	332.92	No	10,000	3%
NO_2	H8H	1-Hour	116.46	66	182.46	No	188	97%
	H1H	Annual	4.90	10.3	15.20	No	100	15%

* - EPA rounding rule, see note 6 in https://www.epa.gov/pm-pollution/timeline-particulate-matter-pm-national-ambient-air-quality-standards-naaqs

Lastly, as there are no Significant Impact Levels (SIL) established for Air Toxics, an evaluation was performed on Volatile Organic Compound (VOC) emissions. The VOC pollutant group does not have an assigned TLV, nor is there a single compound which was identified as a primary concern. Therefore, in this case the TLV for benzene was used as a worst-case. This is shown in Table 19.

Table 19: TLV:MDC Evaluation of VOC Emissions

Pollutant	TLV_{TWA} (mg/m³)	Emission Rate (lb/hr)	$MDC_{8\text{-}hr}$ (µg/m³)[1]	TLV:MDC
VOC (No. 2 Fuel Oil)	1.60	0.437	0.701	2,282
VOC (NG)	1.60	1.2	1.732	924
VOC (NG/LFG Blend)	1.60	0.33	0.472	3,390

[1] – Sample Calculation: ($MDC_{8\text{-}hr}$ @ 1 lb/hr) * (Emission Rate)

When calculated via AERSCREEN at 54 feet from the equipment, criteria pollutants are shown to be below the SILs or NAAQs, as shown in Tables 12, 13, 14 15. For air toxics, VOC emissions are shown in Table 19 to yield TLV:MDC ratios above the 100:1 requirement for the protection of public health, safety, and welfare.

REGULATORY REVIEW

✓ 7 DE Admin. Code 1102:	Permits
✓ 7 DE Admin. Code 1104:	Particulate Emissions from Fuel Burning Equipment
✓ 7 DE Admin. Code 1108:	Sulfur Dioxide Emissions from Fuel Burning Equipment
× 7 DE Admin. Code 1112:	Control of Nitrogen Oxides Emissions
✓ 7 DE Admin. Code 1114:	Visible Emissions
✓ 7 DE Admin. Code 1119:	Control of Odorous Air Contaminants
✓ 7 DE Admin. Code 1120:	New Source Performance Standards
× 7 DE Admin. Code 1124:	Control of Volatile Organic Compound Emissions
✓ 7 DE Admin. Code 1125:	Requirements for Preconstruction Review
× 7 DE Admin. Code 1130:	Title V State Operating Permit Program
× 7 DE Admin. Code 1138:	Emission Standards for Hazardous Air Pollutants for Source Categories
✓ 40 CFR Part 60 Subpart Db:	Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units
✓ 40 CFR Part 60 Subpart WWW:	Standards of Performance for Municipal Solid Waste Landfills That Commenced Construction, Reconstruction, or Modification on or After May 30, 1991, but Before July 18, 2014
✓ 40 CFR 60.8:	Performance Tests
✓ 40 CFR 60.13:	Monitoring Requirements
✓ Appendix F of 40 CFR Part 60	Quality Assurance Procedures
✓ 40 CFR Part 63 Subpart JJJJJJ:	National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources
✓ 40 CFR 63.7:	Performance Testing Requirements
✓ 40 CFR 63.8:	Monitoring Requirements
✓ 40 CFR 63.9:	Notification Requirements
× 40 CFR 64:	Compliance Assurance Monitoring
✓Other Considerations	

7 DE Admin. Code 1102: Permits

7 DE Admin. Code 1102 Section 2.1 states, "…no person shall initiate construction, install, alter or initiate operation of any equipment or facility or air contaminant control device which will emit or

prevent the emission of an air contaminant prior to receiving approval of his application from the Department…"

The equipment described in the application is not exempted in 2.2, and so 7 DE Admin. Code 1102 is applicable.

7 DE Admin. Code 1104: Particulate Emissions from Fuel Burning Equipment

7 DE Admin. Code 1104 Section 1.2 states, "The provisions of this Regulation shall not apply where the heat input capacity of the equipment is less than 1,000,000 BTU per hour."

As the heat input capacity of Boiler 6 is approximately 110 million Btu per hour (MMBtu/hr), the provisions of this regulation apply.

7 DE Admin. Code 1104 Section 2.1 states, "No person shall cause or allow the emission of particulate matter in excess of 0.3 pound per million BTU heat input, maximum two-hour average, from any fuel burning equipment."

$$\frac{2\ \frac{lb}{hr}\ PM}{110\ \frac{MMBtu}{hr}} = 0.018\ \frac{lb\ PM}{MMBtu}\ when\ fired\ on\ No.2\ Fuel\ Oil$$

$$\frac{0.82\ \frac{lb}{hr}\ PM}{110\ \frac{MMBtu}{hr}} = 0.0075\ \frac{lb\ PM}{MMBtu}\ when\ fired\ on\ Natural\ Gas$$

$$\frac{0.69\ \frac{lb}{hr}\ PM}{110\ \frac{MMBtu}{hr}} = 0.0063\ \frac{lb\ PM}{MMBtu}\ when\ fired\ on\ NG\ LFG\ Blend$$

Boiler 6 complies with the 0.3 pounds per million BTU heat input limit of Section 2.1. The requirement in Section 2.1 will be streamlined with stricter requirements in 40 CFR Part 60 Subpart Db § 60.43b(h)(1) and 40 CFR Part 63 Subpart JJJJJJ §63.11201(a). Section 2.1 will be referenced as a streamlined condition.

7 DE Admin. Code 1108: Sulfur Dioxide Emissions from Fuel Burning Equipment

7 DE Admin. Code 1108 Section 2.3 states, "On and after July 1, 2016, no person shall offer for sale, sell, deliver, or purchase any fuel having a sulfur content greater than the limits specified in 2.3.1 through 2.3.3 of this regulation, when such fuel is intended for use in any fuel burning equipment in Delaware, and no person shall use any fuel having a sulfur content greater than the limits specified in 2.3.1 through 2.3.3 of this regulation in any fuel burning equipment in Delaware."

7 DE Admin. Code 1108 Section 2.3.1 states, "For a distillate fuel, except as provided for in 2.4 of this regulation, 15 ppm by weight;"

7 DE Admin Code 1108 Section 4.2 states, "Sulfur concentrations of residual fuels and distillate fuels shall be determined by the following method:

4.2.1 The standard ASTM method D2622-10 "Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-Ray Fluorescence Spectrometry," or

4.2.2 Any alternative method specified in Title 40, Code of Federal Regulations, Part 80, Section 580 (July 2012 edition), or

4.2.3 Any alternative method approved by the Department and the EPA."

7 DE Admin Code 1108 Section 5.1 through 5.1.4.3 state, "Three (3) months after this revision of this regulation becomes effective, any person subject to 2.0 of this regulation, when selling or delivering any fuel oil to be used in Delaware (i.e., the transferor), shall provide to the person receiving the fuel oil (i.e., the transferee) an electronic or paper record that contains the following information:

5.1.1 Name, address and telephone number of the transferor.

5.1.2 Name, address and telephone number of the transferee, and the address where the fuel oil is delivered.

5.1.3 The volume of fuel being sold or delivered, and the date of sale or delivery.

5.1.4 The type of fuel, and the sulfur content of the fuel as a delivered product, determined pursuant to 4.3, 4.4, or 4.5 of this regulation, as applicable, and expressed as one of the following:

5.1.4.1 The actual sulfur content in ppm or percent (%) by weight, or

5.1.4.2 A statement that certifies the sulfur content of the shipment is equal to or below the applicable limit specified in 2.0 of this regulation, or

5.1.4.3 Except for a sale or delivery to an ultimate consumer, a product code or product description that identifies the sulfur content of the shipment as equal to or below the applicable limit specified in 2.0 of this regulation, provided such code or description is standardized throughout the distribution system in which it is used, and each downstream party is given sufficient information to know its full meaning."

7 DE Admin. Code 1108 Section 5.4 states, "For any transferee subject to requirements of a permit issued pursuant to 7 DE Admin. Code 1102, the records established pursuant to 5.1 of this regulation shall be maintained by the transferee for a minimum period of two (2) years from the date the record was generated."

Sections 2.3 and 2.3.1 set limits on the sulfur content of the fuel oil used by Boiler 6, Section 4.2 defines the testing method to be used, while Section 5.4 requires recordkeeping of the information that Section 5.1 requires the seller or deliverer to provide to the Company. These requirements have been added to the permit.

7 DE Admin. Code 1112: Control of Nitrogen Oxides Emissions

7 DE Admin. Code 1112 Section 1.0 states, "Except, as provided in 4.0 of this regulation, the provisions of this regulation are applicable to major stationary sources of nitrogen oxides (NO_x)."

While the Company is a major source of nitrogen oxides, Section 1.0 is referring to a major stationary source in terms of the described equipment. In the case of Boiler 6, the Company has opted to take an enforceable limit on the hours of operation on No. 2 Fuel Oil to ensure that nitrogen oxide emissions fall below the major source threshold. Boiler 6 is therefore not a major source of nitrogen oxides, and Regulation 1112 is not applicable.

7 DE Admin. Code 1114: Visible Emissions

7 DE Admin. Code 1114 Section 2.0 states, "No person shall cause or allow the emission of visible air contaminants or smoke from a stationary or mobile source, the shade or appearance of which is greater than 20% opacity for an aggregate of more than three minutes in any one hour or more than 15 minutes in any 24 hour period."

This condition is applicable to the described equipment and has been included in the permit.

7 DE Admin. Code 1119: Control of Odorous Air Contaminants

7 DE Admin. Code 1119 Section 2.0 states, "No person shall cause or allow the emission of an odorous air contaminant such as to cause a condition of air pollution."

This condition has been included as a state enforceable condition of the permit.

7 DE Admin. Code 1120: New Source Performance Standards

7 DE Admin. Code 1120 Section 26, entitled *Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units* states, "The provisions of Subpart Db – Standards of Performance for New Stationary Sources, Industrial-Commercial-Institutional Steam Generating Units, of Part 60, Title 40 of the Code of Federal Regulations, as published in the Federal Register on November 25, 1986, are hereby adopted by reference."

As Boiler 6 is subject to 40 CFR Part 60 Subpart Db, Section 26 is applicable to the boiler.

7 DE Admin. Code 1120 Sections 1.2.1 through 1.2.1.5 state, "Any person subject to the provisions of this regulation shall furnish the Secretary written notification as follows:

1.2.1.1 A notification of the anticipated date of initial startup of an applicable source not more than 60 days nor less than 30 days prior to such date.

1.2.1.2 A notification of the actual date of initial startup of an applicable source within 15 days after such date.

1.2.1.3 A notification of the date construction or reconstruction of an applicable source is commenced postmarked no later than 30 days after such date. This requirement shall not apply in the case of mass-produced facilities, which are purchased in completed form.

1.2.1.4 A notification of any physical or operational change to an existing facility, which may increase the emission rate of any air pollutant to which a standard applies, unless that change is specifically exempted under an applicable provision. This notice shall be postmarked 60 days or as soon as practicable before the change is commenced and shall include information describing the precise nature of the change, present and proposed emission control systems, productive capacity of the facility before and after the change, and the expected completion date of the change. The Secretary may request additional relevant information subsequent to this notice.

1.2.1.5 A notification of the date upon which demonstration of the continuous monitoring system performances commences. Notification shall be postmarked not less than 30 days prior to such date."

7 DE Admin. Code 1120 Section 1.2.2 states, "Any owner or operator subject to the provisions of 1.0 of this regulation shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an applicable source; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative."

7 DE Admin. Code 1120 Sections 1.2.3 through 1.2.3.2 state, "Each owner or operator required to install a continuous monitoring system shall submit a written report of excess emissions (as defined in applicable provisions) to the Secretary for every calendar quarter. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter and shall include the following information:

1.2.3.1 The magnitude of excessive emissions, any conversion factor or factors used, and the date and time of commencement and completion of each time period of excess emissions.

1.2.3.2 Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the applicable source. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted."

7 DE Admin. Code 1120 Section 1.2.2 states, "Any owner or operator subject to the provisions of 1.0 of this regulation shall maintain a file of all measurements including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by 1.0 of this regulation recorded in a permanent form suitable for inspection. The file shall be retained for at least two years following the date of such measurements, maintenance, reports, and records."

7 DE Admin. Code 1120 Sections 1.3.2 through 1.3.2.2 state, "All continuous monitoring systems and monitoring devices shall be installed and operational prior to conducting performance tests under 1.4 of this regulation. Verification of operational status shall, as minimum, consist of the following:

1.3.2.1 Completion of the conditioning period specified by applicable requirements.

1.3.2.2 For monitoring devices referenced in applicable provisions of this regulation, completion of the manufacturer's written requirements or recommendations for checking the operation or calibration of the device."

7 DE Admin. Code 1120 Sections 1.3.3 through 1.3.3.4 state, "During any performance tests required under 1.4 of this regulation or within 30 days thereafter and at such other times as may be required by the Secretary, the person responsible for any applicable source shall conduct continuous monitoring system performance evaluations and furnish the Secretary within 60 days thereof a written report of the results of such tests. These continuous monitoring system performance evaluations shall be conducted in accordance with the following specifications and procedures:

1.3.3.1 Continuous monitoring systems for measuring opacity of emissions shall comply with Performance Specification 1.
1.3.3.2 Continuous monitoring systems for measuring nitrogen oxides emissions shall comply with Performance Specification 2.
1.3.3.3 [Omitted as it is not applicable]
1.3.3.4 Continuous monitoring systems for measuring the oxygen content or carbon dioxide content of effluent gases shall comply with Performance Specification 3."

7 DE Admin. Code 1120 Section 1.3.4 states, "Performance specifications of 1.0 of this regulation are synonymous with those set forth in Appendix B, 40 CFR 60, dated July 1, 1982, which are hereby adopted by reference with the word substitution "Secretary" for "Administrator"."

7 DE Admin. Code 1120 Section 1.3.5 states, "Calibration checks and zero and span adjustments and reporting of data on all continuous monitoring equipment shall be in accordance with methods approved by the Department. Such methods shall as a minimum, comply with Subsection 60.13(d) in 40 CFR 60, dated July 1, 1982, which is hereby adopted by reference with the word substitution "Secretary" for "Administrator"."

7 DE Admin. Code 1120 Section 1.3.9 states, "All continuous monitoring systems or monitoring devices shall be installed such that representative measurements of emissions or process parameters from the applicable source are obtained. Additional procedures for location of continuous monitoring systems contained in the applicable Performance Specifications of this regulation shall be used."

7 DE Admin. Code 1120 Section 1.3.10 states, "Owners or operators of all continuous monitoring systems for measuring opacity shall reduce all data to 15-second averages. Consecutive 15-second averages, each less than the applicable standard may be recorded cumulatively. The 15-second averages in excess of the applicable standard shall be recorded for the time of occurrence. Any such averages in excess of the applicable standard shall be reported to the Department as excess emissions."

7 DE Admin. Code 1120 Section 1.3.11 states, "For systems other than opacity, one-hour averages shall be computed from four or more data points, equally spaced over each one-hour period. Data recorded during periods of system breakdown, repairs, calibration checks, and zero and span adjustments shall not be included in the data averages computed under 1.0 of this regulation. An arithmetic or integrated average of all data may be used. The data output of all continuous monitoring systems may be recorded in reduced or nonreduced form (e.g., ppm pollutant and percent O_2 or lb/million BTU of pollutant). All excess emissions shall be converted into units of standard using the applicable conversion procedures specified in applicable provisions of this regulation. After conversion into units of the standard, the data may be rounded to the same number of significant digits used in applicable provisions of this regulation to specify the applicable standard (e.g., rounded to the nearest 1% opacity)."

7 DE Admin. Code 1120 Section 1.4.1 states, "Within 60 days after achieving the maximum production rate at which the applicable source will be operated, but not later than 180 days after initial startup of such facility and at such other times as may be required by the Secretary, the person responsible for such source shall conduct performance test or tests and furnish the Secretary a written report of the results of such performance test or tests. The Department may

conduct or contract for the conduct of a performance test whenever it concludes that such test is necessary to determine compliance."

7 DE Admin. Code 1120 Section 1.4.2 states, "Performance tests shall be conducted and data reduced in accordance with the test methods and procedures contained in each applicable provision unless the Secretary (1) specifies or approves, in specific cases, the use of a reference method with minor changes in methodology, (2) approves the use of an equivalent method, (3) approves the use of an alternative method the results of which he has determined to be adequate for indicating whether a specific source is in compliance, or (4) waives the requirement for performance tests because the owner or operator of a source has demonstrated by other means to the Secretary's satisfaction that the applicable source is in compliance with the standard."

7 DE Admin. Code 1120 Section 1.4.3 states, "Performance tests shall be conducted on representative performance of the applicable source. The Secretary may specify additional operating conditions to be tested. The person responsible for the applicable source shall make available to the Department a record of those operating parameters, which the Secretary determines appropriate to establish representative performance of the source. Operations during period of startup, shutdown, and malfunction shall not constitute representative conditions of performance tests unless otherwise specified in the applicable standard. The person responsible for an applicable source shall provide the Secretary 30 days prior notice of the performance test to afford the Secretary the opportunity to have an observer present."

7 DE Admin. Code 1120 Sections 1.4.4 through 1.4.4.4 state, "The person responsible for an applicable source shall provide or cause to be provided, performance testing facilities as follows:

1.4.4.1 Sampling ports adequate for test methods applicable to such facility.
1.4.4.2 Safe sampling platform or platforms.
1.4.4.3 Safe access to sampling platform or platforms.
1.4.4.4 Utilities for sampling and testing equipment."

7 DE Admin. Code 1120 Section 1.4.5 states, "Each performance test shall consist of three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standards. For the purpose of determining compliance, the arithmetic mean of results of the three runs shall apply."

7 DE Admin. Code 1120 Section 1.5.1 states, "Compliance with standards in the regulation, other than opacity standards, shall be determined only by performance test established by 1.4 of this regulation."

7 DE Admin. Code 1120 Section 1.5.2 states, "Compliance with standards in this regulation shall be determined by Reference Methods 1 through 12 and 15 through 25 set forth in Appendix A, 40 CFR Part 60, revised July 1, 1982, which are hereby adopted by reference. Where the person responsible for the applicable source can provide evidence acceptable to the Secretary that the presence of uncombined water is the only reason for failure to meet the opacity standard such failure shall not be a violation of the standard."

7 DE Admin. Code 1120 Section 1.5.3 states, "Compliance with opacity standards in this regulation shall be determined by conducting observations at consecutive 15-second intervals for a period of not less than one hour except that the observations may be discontinued whenever a violation of the applicable standard is recorded. The results of continuous monitoring by transmissometer

which indicate that the opacity at the time visual observations were made was not in excess of the standard are probative but not conclusive evidence of the actual opacity of an emission, provided that the source shall meet the burden of proving that the instrument used meets, at the time of the alleged violation, Performance Specification 1, has been properly maintained and calibrated and that the resulting data have not been tampered with in any way.

The additional procedures, qualifications and testing to be used for visually determining the opacity of emissions shall be those specified in Section 2 and 3 (except for Section 2.5 and the second sentence of Section 2.4) of Reference Method 9 set forth in Appendix A, 40 CFR Part 60, revised July 1, 1982, which are hereby adopted by reference."

7 DE Admin. Code 1120 Section 1.5.4 states, "The opacity standards set forth in this regulation shall apply at all times including periods of startup and shutdown unless the emissions during startup and shutdown are governed by an operation permit."

7 DE Admin. Code 1120 Section 1.5.5 states, "At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any applicable source including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Secretary which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source."

7 DE Admin. Code 1120 Section 1.6 states, "Circumvention. No owner or operator subject to the provisions of 1.0 of this regulation shall build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission, which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous dilutants to achieve compliance with an opacity standard or with a standard, which is based on the concentration of a pollutant in the gases discharged to the atmosphere."

The sections listed above will be incorporated into the permit.

7 DE Admin. Code 1120 Section 2.1 states, "Applicability. Except as provided in 9.0 and 11.0 of this regulation, the provisions of 2.0 of this regulation are applicable to any fuel burning equipment of more than 250 million BTU per hour heat input, which is the applicable source. Any change to existing fuel burning equipment to accommodate the use of combustible fuels other than fossil fuels as defined herein shall not bring that equipment under the applicability of 2.0 of this regulation."

As Boiler 6 is rated at 110 MMBtu/hr, the provision of Section 2.0 do not apply. Section 9.0 pertains to Electric Utility Steam Generating Units, and Section 11.0 pertains to Petroleum Refineries, so these do not apply.

7 DE Admin. Code 1124: Control of Volatile Organic Compound Emissions

7 DE Admin. Code 1124 is not applicable to the described equipment as it does not emit more than 15 pounds of volatile organic compounds (VOC) per day.

7 DE Admin. Code 1125: Requirements for Preconstruction Review

7 DE Admin. Code 1125 Section 2.1 states, "Applicability – The provisions of Section 2.0 of this regulation shall apply to any person responsible for any proposed new major stationary source or any proposed major modification."

While the facility is a major source for NO_X, the Company has opted to take an enforceable limit on the number of hours of operation while firing No. 2 Fuel Oil to avoid the 110 MMBtu boiler being classified as a major source for NO_X. Given the dual source definition used in Delaware, an NSR/PSD Applicability Netting Analysis has been performed. Details of this analysis can be found in the New Source Review (NSR) / Prevention of Significant Deterioration (PSD) section beginning on Page 9 of this memorandum.

New Castle County is in non-attainment for the ozone NAAQS. The pollutants that could trigger NSR are NO_X and VOC as ozone precursors. The net emissions increases for NO_X and VOCs (including changes made during the contemporaneous period) shown in Table 9 do not trigger NSR for these pollutants. Therefore, Section 2 is not applicable to the described equipment.

7 DE Admin. Code 1125 Section 3.1 states, "Definitions – For the purposes of Section 3.0 of this regulation:

"Major Stationary Source" means:

- Any of the following stationary sources of air pollutants which emits or has the potential to emit, 100 tons per year or more of any pollutant subject to regulation under the CAA: Fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input, coal cleaning plants (with thermal dryers), kraft pulp mills, 25ortland cement plants, primary zinc smelters, iron and steel mill plants, primary aluminum ore reduction plants, primary copper smelters, municipal incinerators capable of charging more than 250 tons of refuse per day, hydrofluoric, sulfuric, and nitric acid plants, petroleum refineries, lime plants, phosphate rock processing plants, coke oven batteries, sulfur recovery plants, carbon black plants (furnace process), primary lead smelters, fuel conversion plants, sintering plants, secondary metal production plants, chemical process plants, fossil fuel boilers (or combinations thereof) totaling more than 250 million British thermal units per hour heat input, petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels, taconite ore processing plants, glass fiber processing plants; and charcoal production plants;
- Notwithstanding the stationary source size specified in the above paragraph, any stationary source which emits, or has the potential to emit, 250 tons per year or more of any air pollutant subject to regulation under the CAA; or
- Any physical change that would occur at a stationary source not otherwise qualifying under the preceding paragraph as a major stationary source, if the change would constitute a major stationary source by itself.

A major stationary source that is major for volatile organic compounds or nitrogen oxides shall be considered major for ozone."

While the facility is a major source for NO_X, the 110 MMBtu boiler does not meet the definition of a Major Stationary Source shown in 7 DE Admin. Code 1125 Section 3.1. Given the dual source definition used in Delaware, an NSR/PSD Applicability Netting Analysis has been performed. Details of this analysis can be found in the New Source Review (NSR) / Prevention of Significant Deterioration (PSD) section beginning on Page 9 of this memorandum.

Section 3 was found to only be applicable to CO_2e. Section 3.2 does not provide increment levels for CO_2e, so modeling could not be conducted. PSD is satisfied by applying Best Available Control Technology (BACT) which for CO_2e is maintaining good combustion control.

7 DE Admin. Code 1125 Section 4.4 states in part, "has a potential to emit of equal to or greater than five tons per year of volatile organic compounds (VOC's) or, nitrogen oxides (NOx), or sulfur dioxide (SO2) or sulfur trioxide (SO3) or both [also termed sulfur oxides (SOx)] or, fine particulate matter (PM2.5), or, the potential to emit of equal to or greater than five tons per year, in the aggregate, of any of the hazardous air pollutants (HAP's) listed in Section 112(b) of the federal Clean Air Act."

The described equipment does have the potential to emit greater than 5 tons per year of NO_X. Therefore, Section 4 is applicable to the described equipment. In compliance with Section 4.3.1.2, the Company has submitted as part of the application an MNSR and BACT Analysis for the 110 MMBtu boiler.

The MNSR and BACT Analysis has proposed the use of the following technologies as BACT:

- The use of low nitrogen fuels
- The use of low-excess air firing
- Installation of flue gas recirculation (FGR)
- Installation of an ultra-low NO_X burner (u-LNB)

The Department finds the use of these technologies as BACT acceptable for use with the 110 MMBtu boiler.

7 DE Admin. Code 1130: Title V State Operating Permit Program

7 DE Admin. Code 1130 Sections 3.1 through 3.1.5 state, "Covered Sources. Except as exempted from the requirement to obtain a permit under 3.2 of this regulation and elsewhere herein, the following sources are subject to the permitting requirements under this regulation:

3.1.1 Any major source;
3.1.2 Any source, including an area source, subject to a standard, limitation, or other requirement under Section 111 (Standards of Performance for New Stationary Sources) of the Act;
3.1.3 Any source, including an area source, subject to a standard or other requirement under section 112 (National Emissions Standards for Hazardous Air Pollutants) of the Act, except that a source is not required to obtain a permit solely because it is subject to regulations or requirements under section 112(r) of the Act;
3.1.4 Any affected source; and
3.1.5 Any source that is subject to applicable requirements."

The source (facility) is a major source and currently holds a Title V permit. The 110 MMBtu boiler does trigger Section 3.1.2, but is subsequently exempted by Section 3.2.1. The construction permit will be issued as a Federally Enforceable Regulation 1102 permit, and upon construction of the boiler, the terms will be incorporated into the Title V permit pursuant to 7 DE Admin. Code 1130 Section 7.4.1.5.

7 DE Admin. Code 1138: Emission Standards for Hazardous Air Pollutants for Source Categories

The described equipment is not covered by any of the listed source categories.

40 CFR Part 60 Subpart Db: Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

§ 60.40b Paragraph (a) states, "The affected facility to which this subpart applies is each steam generating unit that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/hr))."

The 110 MMBtu boiler is being constructed after June 19, 1984, and has a heat input capacity greater than 100 MMBtu/hr. Therefore, Subpart Db is applicable.

§ 60.42b Paragraph (e) states, "Except as provided in paragraph (f) of this section, compliance with the emission limits, fuel oil sulfur limits, and/or percent reduction requirements under this section are determined on a 30-day rolling average basis."

Paragraph (f) is not applicable; therefore, compliance will be determined on a 30-day rolling average basis. However, § 60.42b Paragraph (k)(2) (below) exempts the 110 MMBTU boiler from SO_2 emissions limits as long as low sulfur fuels are utilized.

§ 60.42b Paragraph (k)(2) states, "Units firing only very low sulfur oil, gaseous fuel, a mixture of these fuels, or a mixture of these fuels with any other fuels with a potential SO_2 emission rate of 140 ng/J (0.32 lb/MMBtu) heat input or less are exempt from the SO_2 emissions limit in paragraph (k)(1) of this section."

Paragraph (k)(2) does not set an SO_2 standard for emissions. However, an emission limit of 0.32 lb/MMBtu will be added to the permit since exceeding this amount would invalidate the exemption from the emission limit of Paragraph (k)(1).

§ 60.43b Paragraph (f) states, "On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, wood, or mixtures of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. An owner or operator of an affected facility that elects to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart and is subject to a federally enforceable PM limit of 0.030 lb/MMBtu or less is exempt from the opacity standard specified in this paragraph."

The requirements of Paragraph (f) will be streamlined in the permit as they are less strict than the requirements of 7 DE Admin. Code 1114 Section 2.0. § 60.43b Paragraph (f) will be referenced as a streamlined condition.

§ 60.43b Paragraph (g) states, "The PM and opacity standards apply at all times, except during periods of startup, shutdown, or malfunction."

The requirements of Paragraph (g), in regard to opacity, are less strict than the requirements of 7 DE Admin. Code 1120 Section 1.5.4, which does require compliance during periods of startup and shutdown. Therefore, the requirements of 7 DE Admin. Code 1120 Section 1.5.4 will be added to the permit.

§ 60.43b Paragraph (h)(1) states, "Except as provided in paragraphs (h)(2), (h)(3), (h)(4), (h)(5), and (h)(6) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 13 ng/J (0.030 lb/MMBtu) heat input,"

The requirements of Paragraph (h)(1) will be added to the permit.

§ 60.44b Paragraph (h) states, "For purposes of paragraph (i) of this section, the NO_X standards under this section apply at all times including periods of startup, shutdown, or malfunction."

The startup, shutdown, or malfunction (SSM) exemptions in the 40 CFR Part 63 General Provisions were vacated in December 2008 as a result of a decision by the U.S. Court of Appeals for the District of Columbia Circuit. EPA removed SSM exemptions in the NESHAP general provisions in March 2021. EPA has also made several rulemakings with respect to SSM exemptions in State Implementation Plans (SIPs) in the past few years. On September 13, 2022, a coalition of community groups and environmental organizations petitioned EPA to remove SSM exemptions from 40 CFR Part 60 New Source Performance Standards. While EPA has not officially responded to this petition, there have been general statements made by EPA stating that SSM provisions violate the Clean Air Act. As a result, the Department has not included the SSM exemptions in the permit.

§ 60.44b Paragraph (i) states, "Except as provided under paragraph (j) of this section, compliance with the emission limits under this section is determined on a 30-day rolling average basis."

Paragraph (j) is not applicable; therefore, compliance will be determined on a 30-day rolling average basis. This has been added to the permit.

§ 60.44b Paragraph (l) and (l)(1) state, "On and after the date on which the initial performance test is completed or is required to be completed under 60.8, whichever date is first, no owner or operator of an affected facility that commenced construction after July 9, 1997 shall cause to be discharged into the atmosphere from that affected facility any gases that contain NOx (expressed as NO_2) in excess of the following limits:

(1) 86 ng/J (0.20 lb/MMBtu) heat input if the affected facility combusts coal, oil, or natural gas (or any combination of the three), alone or with any other fuels. The affected facility is

not subject to this limit if it is subject to and in compliance with a federally enforceable requirement that limits operation of the facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, and natural gas (or any combination of the three); or"

An emissions limit of 0.20 lb/MMBtu for NO_X will be added to the permit.

§ 60.45b Paragraph (j) states, "The owner or operator of an affected facility that only combusts very low sulfur oil, natural gas, or a mixture of these fuels with any other fuels not subject to an SO_2 standard is not subject to the compliance and performance testing requirements of this section if the owner or operator obtains fuel receipts as described in § 60.49b(r)."

The Company will be required to obtain fuel receipts as described in § 60.49b(r) for all fuels fired. Failure to obtain fuel receipts will immediately trigger any/all applicable SO_2 emissions standards and performance testing requirements. This requirement will be added to the permit.

§ 60.46b Paragraph (a) states, "The PM emission standards and opacity limits under § 60.43b apply at all times except during periods of startup, shutdown, or malfunction. The NO_X emission standards under § 60.44b apply at all times."

The startup, shutdown, or malfunction (SSM) exemptions in the 40 CFR Part 63 General Provisions were vacated in December 2008 as a result of a decision by the U.S. Court of Appeals for the District of Columbia Circuit. EPA removed SSM exemptions in the NESHAP general provisions in March 2021. EPA has also made several rulemakings with respect to SSM exemptions in State Implementation Plans (SIPs) in the past few years. On September 13, 2022, a coalition of community groups and environmental organizations petitioned EPA to remove SSM exemptions from 40 CFR Part 60 New Source Performance Standards. While EPA has not officially responded to this petition, there have been general statements made by EPA stating that SSM provisions violate the Clean Air Act. As a result, the Department has not included the SSM exemptions in the permit.

§ 60.46b Paragraph (b) states, "Compliance with the PM emission standards under § 60.43b shall be determined through performance testing as described in paragraph (d) of this section, except as provided in paragraph (i) of this section."

§ 60.46b Paragraph (c) states, "Compliance with the NO_X emission standards under § 60.44b shall be determined through performance testing under paragraph (e) or (f), or under paragraphs (g) and (h) of this section, as applicable."

§ 60.46b Paragraphs (d) through (d)(2)(ii) state, "To determine compliance with the PM emission limits and opacity limits under § 60.43b, the owner or operator of an affected facility shall conduct an initial performance test as required under § 60.8, and shall conduct subsequent performance tests as requested by the Administrator, using the following procedures and reference methods:

(i) Method 5 of appendix A of this part shall be used at affected facilities without wet flue gas desulfurization (FGD) systems; and

(ii) Method 17 of appendix A-6 of this part may be used at facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160 °C (320 °F). The procedures of sections 8.1 and 11.1 of Method 5B of appendix A-3 of this part may be used in Method 17 of appendix A-6 of this part only if it is used after a wet FGD system. Do not use Method 17 of appendix A-6 of this part after wet FGD systems if the effluent is saturated or laden with water droplets."

The requirements of Paragraphs (b), (c) and (d) will be added to the permit.

§ 60.46b Paragraphs (e) through (e)(1) state, "To determine compliance with the emission limits for NO_X required under § 60.44b, the owner or operator of an affected facility shall conduct the performance test as required under § 60.8 using the continuous system for monitoring NO_X under § 60.48(b).

(1) For the initial compliance test, NO_X from the steam generating unit are monitored for 30 successive steam generating unit operating days and the 30-day average emission rate is used to determine compliance with the NO_X emission standards under § 60.44b. The 30-day average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 30-day test period."

The Company will be required to conduct a performance evaluation for NO_X as required by § 60.46b(e) and § 60.46b(e)(1).

§ 60.47b Paragraph (f) states, "The owner or operator of an affected facility that combusts very low sulfur oil or is demonstrating compliance under § 60.45b(k) is not subject to the emission monitoring requirements under paragraph (a) of this section if the owner or operator maintains fuel records as described in § 60.49b(r)."

The Company will be required to maintain fuel receipts as described in § 60.49b(r) for all fuels fired. Failure to maintain fuel receipts will immediately trigger any/all applicable SO_2 emissions emission monitoring requirements. This requirement will be added to the permit.

§ 60.48b Paragraph (a) states, "Except as provided in paragraph (j) of this section, the owner or operator of an affected facility subject to the opacity standard under § 60.43b shall install, calibrate, maintain, and operate a continuous opacity monitoring systems (COMS) for measuring the opacity of emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility subject to an opacity standard under § 60.43b and meeting the conditions under paragraphs (j)(1), (2), (3), (4), (5), or (6) of this section who elects not to use a COMS shall conduct a performance test using Method 9 of appendix A-4 of this part and the procedures in § 60.11 to demonstrate compliance with the applicable limit in § 60.43b by April 29, 2011, within 45 days of stopping use of an existing COMS, or within 180 days after initial startup of the facility, whichever is later, and shall comply with either paragraphs (a)(1), (a)(2), or (a)(3) of this section. The observation period for Method 9 of appendix A-4 of this part performance tests may be reduced from 3 hours to 60 minutes if all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent during the initial 60 minutes of observation."

Compliance to Paragraph (a) could potentially be exempted by Paragraph (j)(2) or (j)(7). However, the Company has chosen to install a COMS unit.

§ 60.48b Paragraphs (b) through (b)(1) state, "Except as provided under paragraphs (g), (h), and (i) of this section, the owner or operator of an affected facility subject to a NO_X standard under § 60.44b shall comply with either paragraphs (b)(1) or (b)(2) of this section.

(1) Install, calibrate, maintain, and operate CEMS for measuring NO_X and O_2 (or CO_2) emissions discharged to the atmosphere, and shall record the output of the system; or"

§ 60.48b Paragraph (c) states, "The CEMS required under paragraph (b) of this section shall be operated and data recorded during 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."

§ 60.48b Paragraph (d) states, "The 1-hour average NO_X emission rates measured by the continuous NOX monitor required by paragraph (b) of this section and required under § 60.13(h) shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the average emission rates under § 60.44b. The 1-hour averages shall be calculated using the data points required under § 60.13(h)(2)."

§ 60.48b Paragraphs (e) through (e)(2)(i) state, "The procedures under § 60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems.

(1) [Not Applicable]

(2) For affected facilities combusting coal, oil, or natural gas, the span value for NO_X is determined using one of the following procedures:

(i) Except as provided under paragraph (e)(2)(ii) of this section, NO_X span values shall be determined as follows:"

Fuel	Span Values for NO_X (ppm)
Natural Gas	500
Oil	500

§ 60.48b Paragraph (f) states, "When NO_X emission data are not obtained because of CEMS breakdowns, repairs, calibration checks and zero and span adjustments, emission data will be obtained by using standby monitoring systems, Method 7 of appendix A of this part, Method 7A of appendix A of this part, or other approved reference methods to provide emission data for a minimum of 75 percent of the operating hours in each steam generating unit operating day, in at least 22 out of 30 successive steam generating unit operating days."

The Company shall install a NO_X and O_2 (or CO_2) CEMS as required by Paragraph (b) and operated the CEMS as required by Paragraphs (c), (d), (e), and (f).

§ 60.49b Paragraphs (a) through (a)(3) state, "The owner or operator of each affected facility shall submit notification of the date of initial startup, as provided by § 60.7. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of the fuels to be combusted in the affected facility;

(2) [Not Applicable]

(3) The annual capacity factor at which the owner or operator anticipates operating the facility based on all fuels fired and based on each individual fuel fired; and"

§ 60.49b Paragraph (b) states in part, "The owner or operator of each affected facility subject to the SO_2, PM, and/or NO_X emission limits under §§ 60.42b, 60.43b, and 60.44b shall submit to the Administrator the performance test data from the initial performance test and the performance evaluation of the CEMS using the applicable performance specifications in appendix B of this part."

§ 60.49b Paragraphs (d) and (d)(1) state, "Except as provided in paragraph (d)(2) of this section, the owner or operator of an affected facility shall record and maintain records as specified in paragraph (d)(1) of this section.

(1) The owner or operator of an affected facility shall record and maintain records of the amounts of each fuel combusted during each day and calculate the annual capacity factor individually for coal, distillate oil, residual oil, natural gas, wood, and municipal-type solid waste for the 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."

§ 60.49b Paragraphs (g) through (g)(10) state, "Except as provided under paragraph (p) of this section, the owner or operator of an affected facility subject to the NO_X standards under § 60.44b shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date;
(2) The average hourly NO_X emission rates (expressed as NO_2) (ng/J or lb/MMBtu heat input) measured or predicted;
(3) The 30-day average NO_X emission rates (ng/J or lb/MMBtu heat input) calculated at the end of each steam generating unit operating day from the measured or predicted hourly nitrogen oxide emission rates for the preceding 30 steam generating unit operating days;
(4) Identification of the steam generating unit operating days when the calculated 30-day average NO_X emission rates are in excess of the NO_X emissions standards under § 60.44b, with the reasons for such excess emissions as well as a description of corrective actions taken;
(5) 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;
(6) Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data;
(7) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted;
(8) Identification of the times when the pollutant concentration exceeded full span of the CEMS;
(9) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3; and
(10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part."

§ 60.49b Paragraphs (h) through (h)(3) state, "The owner or operator of any affected facility in any category listed in paragraphs (h)(1) or (2) of this section is required to submit excess emission reports for any excess emissions that occurred during the reporting period.

(1) Any affected facility subject to the opacity standards in § 60.43b(f) or to the operating parameter monitoring requirements in § 60.13(i)(1).
(2) Any affected facility that is subject to the NO_X standard of § 60.44b, and that:
(i) Combusts natural gas, distillate oil, gasified coal, or residual oil with a nitrogen content of 0.3 weight percent or less; or
(ii) [Not Applicable]
(3) For the purpose of § 60.43b, excess emissions are defined as all 6-minute periods during which the average opacity exceeds the opacity standards under § 60.43b(f)."

§ 60.49b Paragraph (i) states, "The owner or operator of any affected facility subject to the continuous monitoring requirements for NO_X under § 60.48(b) shall submit reports containing the information recorded under paragraph (g) of this section."

The requirements of § 60.49b Paragraphs (a), (b), (d), (g), (h) and (i) will be added to the permit.

§ 60.49b Paragraph (o) states, "All records required under this section shall be maintained by the owner or operator of the affected facility for a period of 2 years following the date of such record."

This requirement will not be added to the permit as the current requirement for 5 year record retention is stricter.

§ 60.49b Paragraphs (r) through (r)(2)(iv) state, "The owner or operator of an affected facility who elects to use the fuel based compliance alternatives in § 60.42b or § 60.43b shall either:

(1) The owner or operator of an affected facility who elects to demonstrate that the affected facility combusts only very low sulfur oil, natural gas, wood, a mixture of these fuels, or any of these fuels (or a mixture of these fuels) in combination with other fuels that are known to contain an insignificant amount of sulfur in § 60.42b(j) or § 60.42b(k) shall obtain and maintain at the affected facility fuel receipts (such as a current, valid purchase contract, tariff sheet, or transportation contract) from the fuel supplier that certify that the oil meets the definition of distillate oil and gaseous fuel meets the definition of natural gas as defined in § 60.41b and the applicable sulfur limit. For the purposes of this section, the distillate oil need not meet the fuel nitrogen content specification in the definition of distillate oil. Reports shall be submitted to the Administrator certifying that only very low sulfur oil meeting this definition, natural gas, wood, and/or other fuels that are known to contain insignificant amounts of sulfur were combusted in the affected facility during the reporting period; or

(2) The owner or operator of an affected facility who elects to demonstrate compliance based on fuel analysis in § 60.42b or § 60.43b shall develop and submit a site-specific fuel analysis plan to the Administrator for review and approval no later than 60 days before the date you intend to demonstrate compliance. Each fuel analysis plan shall include a minimum initial requirement of weekly testing and each analysis report shall contain, at a minimum, the following information:

(i) The potential sulfur emissions rate of the representative fuel mixture in ng/J heat input;

(ii) The method used to determine the potential sulfur emissions rate of each constituent of the mixture. For distillate oil and natural gas a fuel receipt or tariff sheet is acceptable;

(iii) The ratio of different fuels in the mixture; and

(iv) The owner or operator can petition the Administrator to approve monthly or quarterly sampling in place of weekly sampling."

§ 60.49b Paragraph (w) states, "The reporting period for the reports required under this subpart is each 6 month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period."

The reporting requirements of § 60.49b (r) and (w) will be added to the permit.

40 CFR Part 60 Subpart WWW: Standards of Performance for Municipal Solid Waste Landfills That Commenced Construction, Reconstruction, or Modification on or After May 30, 1991, but Before July 18, 2014

§ 60.752 Paragraph (b)(2)(iii)(B) states, "A control system designed and operated to reduce NMOC by 98 weight-percent, or, when an enclosed combustion device is used for control, to either reduce NMOC by 98 weight percent or reduce the outlet NMOC concentration to less than 20 parts per million by volume, dry basis as hexane at 3 percent oxygen. The reduction efficiency or parts per million by volume shall be established by an initial performance test to be completed no later than 180 days after the initial startup of the approved control system using the test methods specified in § 60.754(d)."

Subpart WWW applies specifically to municipal solid waste landfills. These landfills are required to control the emissions that occur from the breakdown of materials contained within the landfill. This is accomplished via the use of gas wells throughout the landfill which collected the gases created, and pumps that pressurized this gas. The emissions limitations and monitoring requirements of § 60.752 Paragraph (b)(2)(iii)(B) typically would be applicable to a flare located at the landfill. However, as this gas has been collected and offered for sale to the Company for use in equipment (combined heat and power generators, boilers) at their facility, they become subject to these requirements. Therefore, the emissions limitations and monitoring requirements of § 60.752 Paragraph (b)(2)(iii)(B) will be added to the permit.

40 CFR 60.8: Performance Tests

§ 60.8 Paragraph (a) states, "Except as specified in paragraphs (a)(1),(a)(2), (a)(3), and (a)(4) of this section, within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility, or at such other times specified by this part, and at such other times as may be required by the Administrator under section 114 of the Act, the owner or operator of such facility shall conduct performance test(s) and furnish the Administrator a written report of the results of such performance test(s)."

This requirement has been included in the permit.

§ 60.8 Paragraph (d) states, "The owner or operator of an affected facility shall provide the Administrator at least 30 days prior notice of any performance test, except as specified under other subparts, to afford the Administrator the opportunity to have an observer present. If after 30 days notice for an initially scheduled performance test, there is a delay (due to operational problems, etc.) in conducting the scheduled performance test, the owner or operator of an affected facility shall notify the Administrator (or delegated State or local agency) as soon as possible of any delay in the original test date, either by providing at least 7 days prior notice of the rescheduled date of the performance test, or by arranging a rescheduled date with the Administrator (or delegated State or local agency) by mutual agreement."

This requirement has been included in the permit, but with the stricter timing of a minimum of 45 days required by 7 DE Admin. Code 1117 Section 2.2.

§ 60.8 Paragraphs (e) through (e)(4) state, "The owner or operator of an affected facility shall provide, or cause to be provided, performance testing facilities as follows:

(1) Sampling ports adequate for test methods applicable to such facility. This includes
(i) constructing the air pollution control system such that volumetric flow rates and pollutant emission rates can be accurately determined by applicable test methods and procedures and
(ii) providing a stack or duct free of cyclonic flow during performance tests, as demonstrated by applicable test methods and procedures.
(2) Safe sampling platform(s).
(3) Safe access to sampling platform(s).
(4) Utilities for sampling and testing equipment."

These requirements have been included in the permit.

§ 60.8 Paragraphs (f) through (f)(2)(vi) state, "Unless otherwise specified in the applicable subpart, each performance test shall consist of three separate runs using the applicable test method.
(1) Each run shall be conducted for the time and under the conditions specified in the applicable standard. For the purpose of determining compliance with an applicable standard, the arithmetic means of results of the three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the three runs must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances, beyond the owner or operator's control, compliance may, upon the Administrator's approval, be determined using the arithmetic mean of the results of the two other runs.
(2) Contents of report (electronic or paper submitted copy). Unless otherwise specified in a relevant standard or test method, or as otherwise approved by the Administrator in writing, the report for a performance test shall include the elements identified in paragraphs (f)(2)(i) through (vi) of this section.
(i) General identification information for the facility including a mailing address, the physical address, the owner or operator or responsible official (where applicable) and his/her email address, and the appropriate Federal Registry System (FRS) number for the facility.
(ii) Purpose of the test including the applicable regulation(s) requiring the test, the pollutant(s) and other parameters being measured, the applicable emission standard and any process parameter component, and a brief process description.
(iii) Description of the emission unit tested including fuel burned, control devices, and vent characteristics; the appropriate source classification code (SCC); the permitted maximum process rate (where applicable); and the sampling location.
(iv) Description of sampling and analysis procedures used and any modifications to standard procedures, quality assurance procedures and results, record of process operating conditions that demonstrate the applicable test conditions are met, and values for any operating parameters for which limits were being set during the test.
(v) Where a test method requires you record or report, the following shall be included: Record of preparation of standards, record of calibrations, raw data sheets for field sampling, raw data sheets for field and laboratory analyses, chain-of-custody documentation, and example calculations for reported results.
(vi) Identification of the company conducting the performance test including the primary office address, telephone number, and the contact for this test program including his/her email address."

These requirements have been included in the permit.

§ 60.8 Paragraphs (g) and (g)(1) state in part, "The performance testing shall include a test method performance audit (PA) during the performance test. The PAs consist of blind audit samples supplied by an accredited audit sample provider and analyzed during the performance test in order to provide a measure of test data bias. Gaseous audit samples are designed to audit the performance of the sampling system as well as the analytical system and must be collected by the sampling system during the compliance test just as the compliance samples are collected. If a liquid or solid audit sample is designed to audit the sampling system, it must also be collected by the sampling system during the compliance test. If multiple sampling systems or sampling trains are used during the compliance test for any of the test methods, the tester is only required to use one of the sampling systems per method to collect the audit sample. The audit sample must be analyzed by the same analyst using the same analytical reagents and analytical system and at the same time as the compliance samples. Retests are required when there is a failure to produce acceptable results for an audit sample. However, if the audit results do not affect the compliance or noncompliance status of the affected facility, the compliance authority may waive the reanalysis requirement, further audits, or retests and accept the results of the compliance test. Acceptance of the test results shall constitute a waiver of the reanalysis requirement, further audits, or retests. The compliance authority may also use the audit sample failure and the compliance test results as evidence to determine the compliance or noncompliance status of the affected facility. A blind audit sample is a sample whose value is known only to the sample provider and is not revealed to the tested facility until after they report the measured value of the audit sample. For pollutants that exist in the gas phase at ambient temperature, the audit sample shall consist of an appropriate concentration of the pollutant in air or nitrogen that can be introduced into the sampling system of the test method at or near the same entry point as a sample from the emission source. If no gas phase audit samples are available, an acceptable alternative is a sample of the pollutant in the same matrix that would be produced when the sample is recovered from the sampling system as required by the test method. For samples that exist only in a liquid or solid form at ambient temperature, the audit sample shall consist of an appropriate concentration of the pollutant in the same matrix that would be produced when the sample is recovered from the sampling system as required by the test method. An accredited audit sample provider (AASP) is an organization that has been accredited to prepare audit samples by an independent, third party accrediting body.

(1) The source owner, operator, or representative of the tested facility shall obtain an audit sample, if commercially available, from an AASP for each test method used for regulatory compliance purposes. No audit samples are required for the following test methods: Methods 3A and 3C of appendix A–3 of part 60, Methods 6C, 7E, 9, and 10 of appendix A–4 of part 60, Methods 18 and 19 of appendix A–6 of part 60, Methods 20, 22, and 25A of appendix A–7 of part 60, Methods 30A and 30B of appendix A–8 of part 60, and Methods 303, 318, 320, and 321 of appendix A of part 63 of this chapter. If multiple sources at a single facility are tested during a compliance test event, only one audit sample is required for each method used during a compliance test. The compliance authority responsible for the compliance test may waive the requirement to include an audit sample if they believe that an audit sample is not necessary. "Commercially available" means that two or more independent AASPs have blind audit samples available for purchase. If the source owner, operator, or representative cannot find an audit sample for a specific method, the owner, operator, or representative shall consult the EPA Web site at the following URL, www.epa.gov/ttn/emc, to confirm whether there is a source that can supply an audit sample for that method. If the EPA Web site does not list an available audit sample at least 60 days prior to the beginning of the compliance test, the source owner, operator, or representative shall not be required to include an audit sample as part of the quality assurance program for the compliance test.

When ordering an audit sample, the source owner, operator, or representative shall give the sample provider an estimate for the concentration of each pollutant that is emitted by the source or the estimated concentration of each pollutant based on the permitted level and the name, address, and phone number of the compliance authority. The source owner, operator, or representative shall report the results for the audit sample along with a summary of the emission test results for the audited pollutant to the compliance authority and shall report the results of the audit sample to the AASP. The source owner, operator, or representative shall make both reports at the same time and in the same manner or shall report to the compliance authority first and then report to the AASP. If the method being audited is a method that allows the samples to be analyzed in the field and the tester plans to analyze the samples in the field, the tester may analyze the audit samples prior to collecting the emission samples provided a representative of the compliance authority is present at the testing site. The tester may request and the compliance authority may grant a waiver to the requirement that a representative of the compliance authority must be present at the testing site during the field analysis of an audit sample. The source owner, operator, or representative may report the results of the audit sample to the compliance authority and report the results of the audit sample to the AASP prior to collecting any emission samples. The test protocol and final test report shall document whether an audit sample was ordered and utilized and the pass/fail results as applicable."

Paragraph (g) requires the addition of blind audit samples to the performance testing. Paragraph (g)(1) exempts opacity, NO_X, O_2, and CO_2 testing from this requirement. However, no exemption for PM testing is listed, therefore a blind audit sample for particulate matter is required if audit samples are commercially available. This requirement will be added to the permit.

§ 60.8 Paragraph (h) states, "Unless otherwise specified in the applicable subpart, each test location must be verified to be free of cyclonic flow and evaluated for the existence of emission gas stratification and the required number of sampling traverse points. If other procedures are not specified in the applicable subpart to the regulations, use the appropriate procedures in Method 1 to check for cyclonic flow and Method 7E to evaluate emission gas stratification and selection of sampling points."

This requirement has been included in the permit.

40 CFR 60.13: Monitoring Requirements

§ 60.13 Paragraph (a) states, "For the purposes of this section, all continuous monitoring systems required under applicable subparts shall be subject to the provisions of this section upon promulgation of performance specifications for continuous monitoring systems under appendix B to this part and, if the continuous monitoring system is used to demonstrate compliance with emission limits on a continuous basis, appendix F to this part, unless otherwise specified in an applicable subpart or by the Administrator. Appendix F is applicable December 4, 1987."

§ 60.13 Paragraph (b) states, "All continuous monitoring systems and monitoring devices shall be installed and operational prior to conducting performance tests under § 60.8. Verification of operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device."

§ 60.13 Paragraph (d)(1) states, "Owners and operators of a CEMS installed in accordance with the provisions of this part, must check the zero (or low level value between 0 and 20 percent of span value) and span (50 to 100 percent of span value) calibration drifts at least once each operating day in accordance with a written procedure. The zero and span must, at a minimum, be adjusted whenever either the 24-hour zero drift or the 24-hour span drift exceeds two times the limit of the applicable performance specification in appendix B of this part. The system must allow the amount of the excess zero and span drift to be recorded and quantified whenever specified. Owners and operators of a COMS installed in accordance with the provisions of this part must check the zero and upscale (span) calibration drifts at least once daily. For a particular COMS, the acceptable range of zero and upscale calibration materials is defined in the applicable version of PS–1 in appendix B of this part. For a COMS, the optical surfaces, exposed to the effluent gases, must be cleaned before performing the zero and upscale drift adjustments, except for systems using automatic zero adjustments. The optical surfaces must be cleaned when the cumulative automatic zero compensation exceeds 4 percent opacity."

§ 60.13 Paragraph (d)(2) states, "Unless otherwise approved by the Administrator, the following procedures must be followed for a COMS. Minimum procedures must include an automated method for producing a simulated zero opacity condition and an upscale opacity condition using a certified neutral density filter or other related technique to produce a known obstruction of the light beam. Such procedures must provide a system check of all active analyzer internal optics with power or curvature, all active electronic circuitry including the light source and photodetector assembly, and electronic or electro-mechanical systems and hardware and or software used during normal measurement operation."

§ 60.13 Paragraphs (e) through (e)(2) state, "Except for system breakdowns, repairs, calibration checks, and zero and span adjustments required under paragraph (d) of this section, all continuous monitoring systems shall be in continuous operation and shall meet minimum frequency of operation requirements as follows:

(1) All continuous monitoring systems referenced by paragraph (c) of this section for measuring opacity of emissions shall complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.
(2) All continuous monitoring systems referenced by paragraph (c) of this section for measuring emissions, except opacity, shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period."

§ 60.13 Paragraph (h)(1) states, "Owners or operators of all continuous monitoring systems for measurement of opacity shall reduce all data to 6-minute averages and for continuous monitoring systems other than opacity to 1-hour averages for time periods as defined in § 60.2. Six-minute opacity averages shall be calculated from 36 or more data points equally spaced over each 6-minute period."

The data reduction provisions for COMS will be streamlined with the stricter 15 second averages required by 7 DE Admin. Code 1120 Section 1.3.10.

§ 60.13 Paragraphs (h)(2) through (h)(2)(ix) state, "For continuous monitoring systems other than opacity, 1-hour averages shall be computed as follows, except that the provisions pertaining to the validation of partial operating hours are only applicable for affected facilities that are required by the applicable subpart to include partial hours in the emission calculations:

(i) Except as provided under paragraph (h)(2)(iii) of this section, for a full operating hour (any clock hour with 60 minutes of unit operation), at least four valid data points are required to calculate the hourly average, i.e., one data point in each of the 15-minute quadrants of the hour.

(ii) Except as provided under paragraph (h)(2)(iii) of this section, for a partial operating hour (any clock hour with less than 60 minutes of unit operation), at least one valid data point in each 15-minute quadrant of the hour in which the unit operates is required to calculate the hourly average.

(iii) For any operating hour in which required maintenance or quality-assurance activities are performed:

(A) If the unit operates in two or more quadrants of the hour, a minimum of two valid data points, separated by at least 15 minutes, is required to calculate the hourly average; or

(B) If the unit operates in only one quadrant of the hour, at least one valid data point is required to calculate the hourly average.

(iv) If a daily calibration error check is failed during any operating hour, all data for that hour shall be invalidated, unless a subsequent calibration error test is passed in the same hour and the requirements of paragraph (h)(2)(iii) of this section are met, based solely on valid data recorded after the successful calibration.

(v) For each full or partial operating hour, all valid data points shall be used to calculate the hourly average.

(vi) Except as provided under paragraph (h)(2)(vii) of this section, data recorded during periods of continuous monitoring system breakdown, repair, calibration checks, and zero and span adjustments shall not be included in the data averages computed under this paragraph.

(vii) Owners and operators complying with the requirements of § 60.7(f)(1) or (2) must include any data recorded during periods of monitor breakdown or malfunction in the data averages.

(viii) When specified in an applicable subpart, hourly averages for certain partial operating hours shall not be computed or included in the emission averages (e.g., hours with < 30 minutes of unit operation under § 60.47b(d)).

(ix) Either arithmetic or integrated averaging of all data may be used to calculate the hourly averages. The data may be recorded in reduced or nonreduced form (e.g., ppm pollutant and percent O2 or ng/J of pollutant)."

§ 60.13 Paragraph (h)(3) states, "All excess emissions shall be converted into units of the standard using the applicable conversion procedures specified in the applicable subpart. After conversion into units of the standard, the data may be rounded to the same number of significant digits used in the applicable subpart to specify the emission limit."

The monitoring requirements of § 60.13 listed above will be added to the permit, with § 60.13 Paragraph (h)(1) being streamlined as noted above.

Appendix F of 40 CFR Part 60: Quality Assurance Procedures

Procedure 1, Section 3 states, "Each source owner or operator must develop and implement a QC program. As a minimum, each QC program must include written procedures which should describe in detail, complete, step-by-step procedures and operations for each of the following activities:

1. Calibration of CEMS.
2. CD determination and adjustment of CEMS.
3. Preventive maintenance of CEMS (including spare parts inventory).
4. Data recording, calculations, and reporting.
5. Accuracy audit procedures including sampling and analysis methods.
6. Program of corrective action for malfunctioning CEMS.

As described in section 5.2, whenever excessive inaccuracies occur for two consecutive quarters, the source owner or operator must revise the current written procedures or modify or replace the CEMS to correct the deficiency causing the excessive inaccuracies.

These written procedures must be kept on record and available for inspection by the enforcement agency."

Boiler 6 is subject to Appendix F due to its reference in 40 CFR § 60.13(a). The requirements set forth in Section 3 will be added to the permit, and other sections of Appendix F will be included by reference only.

40 CFR Part 63 Subpart JJJJJJ: National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources

§ 63.11193 states, "Am I subject to this subpart?
You are subject to this subpart if you own or operate an industrial, commercial, or institutional boiler as defined in § 63.11237 that is located at, or is part of, an area source of hazardous air pollutants (HAP), as defined in § 63.2, except as specified in § 63.11195."

Boiler 6 is subject to this subpart as the Company is an area source of HAP, and it is not subject to any of the exemptions listed in § 63.11195.

§ 63.11194 Paragraphs (a) and (a)(2) state, "What is the affected source of this subpart?
This subpart applies to each new, reconstructed, or existing affected source as defined in paragraphs (a)(1) and (2) of this section.

(2) The affected source of this subpart is each new or reconstructed industrial, commercial, or institutional boiler within a subcategory, as listed in § 63.11200 and as defined in § 63.11237, located at an area source."

§ 63.11194 Paragraph (c) states, "An affected source is a new source if you commenced construction of the affected source after June 4, 2010, and the boiler meets the applicability criteria at the time you commence construction."

Boiler 6 is a new affected source.

§ 63.11196 Paragraph (c) states, "If you start up a new affected source after May 20, 2011, you must achieve compliance with the provisions of this subpart upon startup of your affected source."

Boiler 6 needs to comply with the provisions of this subpart upon startup.

§ 63.11200 states, "What are the subcategories of boilers?
The subcategories of boilers, as defined in § 63.11237 are:
(c) Oil."

Since the Company would like to fire Boiler 6 on No. 2 fuel oil at any time (not only during times of natural gas curtailment), it belongs to the oil subcategory of boilers.

§ 63.11201 Paragraphs (a) through (d) state, "What standards must I meet?
(a) You must comply with each emission limit specified in Table 1 to this subpart that applies to your boiler.
(b) You must comply with each work practice standard, emission reduction measure, and management practice specified in Table 2 to this subpart that applies to your boiler. An energy assessment completed on or after January 1, 2008 that meets or is amended to meet the energy assessment requirements in Table 2 to this subpart satisfies the energy assessment requirement. A facility that operates under an energy management program established through energy management systems compatible with ISO 50001, that includes the affected units, also satisfies the energy assessment requirement.
(c) You must comply with each operating limit specified in Table 3 to this subpart that applies to your boiler.
(d) These standards apply at all times the affected boiler is operating, except during periods of startup and shutdown as defined in § 63.11237, during which time you must comply only with Table 2 to this subpart."

Table 1 to Subpart JJJJJJ of Part 63 – Emission Limits (Excerpt)

If your boiler is in this subcategory…	For the following pollutants…	You must achieve less than or equal to the following emission limits, except during periods of startup and shutdown…
5. New oil-fired boilers with heat input capacity of 10 MMBtu/hr or greater that do not meet the definition of seasonal boiler or limited-use boiler	PM (Filterable)	3.0E-02 lb per MMBtu of heat input.

Table 2 to Subpart JJJJJJ of Part 63 – Work Practice Standards, Emission Reduction Measures, and Management Practices (Excerpt)

If your boiler is in this subcategory…	You must meet the following…
1. Existing or new coal-fired, new biomass-fired, or new oil-fired boilers (units with heat input capacity of 10 MMBtu/hr or greater)	Minimize the boiler's startup and shutdown periods and conduct startups and shutdowns according to the manufacturer's recommended procedures. If manufacturer's recommended procedures are not available, you must follow recommended procedures for a unit of similar design for which manufacturer's recommended procedures are available.

If your boiler is in this subcategory…	You must meet the following…
5. New oil-fired boilers with heat input capacity greater than 5 MMBtu/hr that do not meet the definition of seasonal boiler or limited-use boiler, or use an oxygen trim system that maintains an optimum air-to-fuel ratio	Conduct a tune-up of the boiler biennially as specified in § 63.11223.

Table 3 to Subpart JJJJJJ of Part 63 – Operating Limits for Boilers with Emission Limits (Excerpt)

If you demonstrate compliance with applicable emission limits using…	You must meet these operating limits except during periods of startup and shutdown…
7. Performance stack testing	For boilers that demonstrate compliance with a performance stack test, maintain the operating load of each unit such that it does not exceed 110 percent of the average operating load recorded during the most recent performance stack test.

The emission limits, work practice standards and operating limits shown above will be added to the permit, with the exception of the startup and shutdown provisions shown in § 63.11201 Paragraph (d) and Tables 1, 2, and 3 to Subpart JJJJJJ of Part 63.

The startup, shutdown, or malfunction (SSM) exemptions in the 40 CFR Part 63 General Provisions were vacated in December 2008 as a result of a decision by the U.S. Court of Appeals for the District of Columbia Circuit. EPA removed SSM exemptions in the NESHAP general provisions in March 2021. EPA has also made several rulemakings with respect to SSM exemptions in State Implementation Plans (SIPs) in the past few years. On September 13, 2022, a coalition of community groups and environmental organizations petitioned EPA to remove SSM exemptions from 40 CFR Part 60 New Source Performance Standards. While EPA has not officially responded to this petition, there have been general statements made by EPA stating that SSM provisions violate the Clean Air Act. As a result, the Department has not included the SSM exemptions in the permit.

§ 63.11205 Paragraphs (a) and (b) state, "What are my general requirements for complying with this subpart?

(a) At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require you to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

(b) You must demonstrate compliance with all applicable emission limits using performance stack testing, fuel analysis, or a continuous monitoring system (CMS), including a continuous emission monitoring system (CEMS), a continuous opacity monitoring system (COMS), or a continuous parameter monitoring system (CPMS), where applicable. You may demonstrate compliance with the applicable mercury emission limit using fuel analysis if the emission rate calculated according to § 63.11211(c) is less than the applicable emission limit. Otherwise, you must demonstrate compliance using stack testing."

(c) If you demonstrate compliance with any applicable emission limit through performance stack testing and subsequent compliance with operating limits (including the use of CPMS), with a CEMS, or with a COMS, you must develop a site-specific monitoring plan according to the requirements in paragraphs (c)(1) through (3) of this section for the use of any CEMS, COMS, or CPMS. This requirement also applies to you if you petition the EPA Administrator for alternative monitoring parameters under § 63.8(f).

(1) For each CMS required in this section (including CEMS, COMS, or CPMS), you must develop, and submit to the Administrator for approval upon request, a site-specific monitoring plan that addresses paragraphs (c)(1)(i) through (vi) of this section. You must submit this site-specific monitoring plan, if requested, at least 60 days before your initial performance evaluation of your CMS. This requirement to develop and submit a site-specific monitoring plan does not apply to affected sources with existing CEMS or COMS operated according to the performance specifications under appendix B to part 60 of this chapter and that meet the requirements of § 63.11224.

(i) Installation of the CMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (e.g., on or downstream of the last control device);

(ii) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems; and

(iii) Performance evaluation procedures and acceptance criteria (e.g., calibrations).

(iv) Ongoing operation and maintenance procedures in accordance with the general requirements of § 63.8(c)(1)(ii), (c)(3), and (c)(4)(ii);

(v) Ongoing data quality assurance procedures in accordance with the general requirements of § 63.8(d); and

(vi) Ongoing recordkeeping and reporting procedures in accordance with the general requirements of § 63.10(c) (as applicable in Table 8 to this subpart), (e)(1), and (e)(2)(i).

(2) You must conduct a performance evaluation of each CMS in accordance with your site-specific monitoring plan.

(3) You must operate and maintain the CMS in continuous operation according to the site-specific monitoring plan."

The requirements of 63.11205 Paragraphs (a) and (b) listed above will be added to the permit.

§ 63.11210 Paragraphs (a), (d), (f), (g), (j), (j)(2) and (j)(3) state, "What are my initial compliance requirements and by what date must I conduct them?

(a) You must demonstrate initial compliance with each emission limit specified in Table 1 to this subpart that applies to you by either conducting performance (stack) tests, as applicable, according to § 63.11212 and Table 4 to this subpart or, for mercury, conducting fuel analyses, as applicable, according to § 63.11213 and Table 5 to this subpart.

(d) For new or reconstructed affected boilers that have applicable emission limits, you must demonstrate initial compliance with the applicable emission limits no later than 180 days after March 21, 2011 or within 180 days after startup of the source, whichever is later, according to § 63.7(a)(2)(ix). (f) For new or reconstructed boilers that combust only ultra-low-sulfur liquid fuel as defined in § 63.11237, you are not subject to the PM emission limit in Table 1 of this subpart providing you monitor and record on a monthly basis the type of fuel combusted. If you intend to burn a fuel other than ultra-low-sulfur liquid fuel or gaseous fuels as defined in § 63.11237, you must conduct a performance test within 60 days of burning the new fuel.

(g) For new or reconstructed affected boilers that have applicable work practice standards or management practices, you are not required to complete an initial performance tune-up, but you are required to complete the applicable biennial or 5-year tune-up as specified in § 63.11223 no later than 25 months or 61 months, respectively, after the initial startup of the new or reconstructed affected source.

(j) For boilers located at existing major sources of HAP that limit their potential to emit (e.g., make a physical change or take a permit limit) such that the existing major source becomes an area source, you must comply with the applicable provisions as specified in paragraphs (j)(1) through (3) of this section.

(2) Any new or reconstructed boiler at the existing source must demonstrate compliance with subpart JJJJJJ within 180 days of the later of March 21, 2011 or startup.

(3) Notification of such changes must be submitted according to § 63.11225(g)."

The requirements of 63.11210 Paragraphs (a), (d), (f), (g) and (j) listed above will be added to the permit.

§ 63.11211 Paragraph (a) states, "How do I demonstrate initial compliance with the emission limits?

(a) For affected boilers that demonstrate compliance with any of the emission limits of this subpart through performance (stack) testing, your initial compliance requirements include conducting performance tests according to § 63.11212 and Table 4 to this subpart, conducting a fuel analysis for each type of fuel burned in your boiler according to § 63.11213 and Table 5 to this subpart, establishing operating limits according to § 63.11222, Table 6 to this subpart and paragraph (b) of this section, as applicable, and conducting CMS performance evaluations according to § 63.11224. For affected boilers that burn a single type of fuel, you are exempted from the compliance requirements of conducting a fuel analysis for each type of fuel burned in your boiler. For purposes of this subpart, boilers that use a supplemental fuel only for startup, unit shutdown, and transient flame stability purposes still qualify as affected boilers that burn a single type of fuel, and the supplemental fuel is not subject to the fuel analysis requirements under § 63.11213 and Table 5 to this subpart."

The requirements of § 63.11211 Paragraph (a) will be added to the permit.

§ 63.11212 Paragraphs (a) through (e) state, "What stack tests and procedures must I use for the performance tests?

> (a) You must conduct all performance tests according to § 63.7(c), (d), (f), and (h). You must also develop a site-specific test plan according to the requirements in § 63.7(c).
> (b) You must conduct each stack test according to the requirements in Table 4 to this subpart. Boilers that use a CEMS for carbon monoxide (CO) are exempt from the initial CO performance testing in Table 4 to this subpart and the oxygen concentration operating limit requirement specified in Table 3 to this subpart.
> (c) You must conduct performance stack tests at the representative operating load conditions while burning the type of fuel or mixture of fuels that have the highest emissions potential for each regulated pollutant, and you must demonstrate initial compliance and establish your operating limits based on these performance stack tests. For subcategories with more than one emission limit, these requirements could result in the need to conduct more than one performance stack test. Following each performance stack test and until the next performance stack test, you must comply with the operating limit for operating load conditions specified in Table 3 to this subpart.
> (d) You must conduct a minimum of three separate test runs for each performance stack test required in this section, as specified in § 63.7(e)(3) and in accordance with the provisions in Table 4 to this subpart.
> (e) To determine compliance with the emission limits, you must use the F-Factor methodology and equations in sections 12.2 and 12.3 of EPA Method 19 of appendix A-7 to part 60 of this chapter to convert the measured PM concentrations and the measured mercury concentrations that result from the performance test to pounds per million Btu heat input emission rates."
>
> The requirements of § 63.11212 Paragraphs (a) through (e) will be added to the permit.

§ 63.11214 Paragraphs (b) and (d) state, "How do I demonstrate initial compliance with the work practice standard, emission reduction measures, and management practice?

> (b) If you own or operate an existing or new biomass-fired boiler or an existing or new oil-fired boiler, you must conduct a performance tune-up according to § 63.11210(c) or (g), as applicable, and § 63.11223(b). If you own or operate an existing biomass-fired boiler or existing oil-fired boiler, you must submit a signed statement in the Notification of Compliance Status report that indicates that you conducted an initial tune-up of the boiler.
> (d) If you own or operate a boiler subject to emission limits in Table 1 of this subpart, you must minimize the boiler's startup and shutdown periods following the manufacturer's recommended procedures, if available. If manufacturer's recommended procedures are not available, you must follow recommended procedures for a unit of similar design for which manufacturer's recommended procedures are available. You must submit a signed statement in the Notification of Compliance Status report that indicates that you conducted startups and shutdowns according to the manufacturer's recommended procedures or procedures specified for a boiler of similar design if manufacturer's recommended procedures are not available."
>
> The requirements of § 63.11214 Paragraphs (b) and (d) will be added to the permit.

§ 63.11220 Paragraph (a) states, "When must I conduct subsequent performance tests or fuel analyses?

(a) If your boiler has a heat input capacity of 10 million Btu per hour or greater, you must conduct all applicable performance (stack) tests according to § 63.11212 on a triennial basis, except as specified in paragraphs (b) through (e) of this section. Triennial performance tests must be completed no more than 37 months after the previous performance test."

The requirements of § 63.11220 Paragraph (a) will be added to the permit.

§ 63.11221 Paragraphs (a) through (d) state, "Is there a minimum amount of monitoring data I must obtain?

(a) You must monitor and collect data according to this section and the site-specific monitoring plan required by § 63.11205(c).

(b) You must operate the monitoring system and collect data at all required intervals at all times the affected source is operating and compliance is required, except for periods of monitoring system malfunctions or out-of-control periods (see § 63.8(c)(7) of this part), repairs associated with monitoring system malfunctions or out-of-control periods, and required monitoring system quality assurance or quality control activities including, as applicable, calibration checks, required zero and span adjustments, and scheduled CMS maintenance as defined in your site-specific monitoring plan. A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You are required to complete monitoring system repairs in response to monitoring system malfunctions or out-of-control periods and to return the monitoring system to operation as expeditiously as practicable.

(c) You may not use data collected during periods of startup and shutdown, monitoring system malfunctions or out-of-control periods, repairs associated with monitoring system malfunctions or out-of-control periods, or required monitoring system quality assurance or quality control activities in calculations used to report emissions or operating levels. Any such periods must be reported according to the requirements in § 63.11225. You must use all the data collected during all other periods in assessing the operation of the control device and associated control system.

(d) Except for periods of monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, and required monitoring system quality assurance or quality control activities (including, as applicable, calibration checks, required zero and span adjustments, and scheduled CMS maintenance as defined in your site-specific monitoring plan), failure to collect required data is a deviation of the monitoring requirements."

The requirements of § 63.11221 Paragraphs (a) through (d) will be added to the permit.

§ 63.11222 Paragraphs (a) through (a)(2) and (b) state, "How do I demonstrate continuous compliance with the emission limits?

(a) You must demonstrate continuous compliance with each emission limit and operating limit in Tables 1 and 3 to this subpart that applies to you according to the methods specified in Table 7 to this subpart and to paragraphs (a)(1) through (4) of this section.

(1) Following the date on which the initial compliance demonstration is completed or is required to be completed under §§ 63.7 and 63.11196, whichever date comes first, you must continuously monitor the operating parameters. Operation above the established maximum, below the established minimum, or outside the allowable range of the operating limits specified in paragraph (a) of this section constitutes a

deviation from your operating limits established under this subpart, except during performance tests conducted to determine compliance with the emission and operating limits or to establish new operating limits. Operating limits are confirmed or reestablished during performance tests.

(2) If you have an applicable mercury or PM emission limit, you must keep records of the type and amount of all fuels burned in each boiler during the reporting period. If you have an applicable mercury emission limit, you must demonstrate that all fuel types and mixtures of fuels burned would result in lower emissions of mercury than the applicable emission limit (if you demonstrate compliance through fuel analysis), or result in lower fuel input of mercury than the maximum values calculated during the last performance stack test (if you demonstrate compliance through performance stack testing).

(b) You must report each instance in which you did not meet each emission limit and operating limit in Tables 1 and 3 to this subpart that apply to you. These instances are deviations from the emission limits in this subpart. These deviations must be reported according to the requirements in § 63.11225."

Table 7 to Subpart JJJJJJ of Part 63 – Demonstrating Continuous Compliance (Excerpt)

If you must meet the following operating limits…	You must demonstrate continuous compliance by …
9. Boiler operating load	a. Collecting operating load data (fuel feed rate or steam generation data) every 15 minutes; and
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average at or below the operating limit established during the performance test according to § 63.11212(c) and Table 6 to this subpart.

The requirements of § 63.11222 Paragraph (a), (b) and Table 7(9) will be added to the permit.

§ 63.11223 Paragraphs (a), (b) and (g) state, "How do I demonstrate continuous compliance with the work practice and management practice standards?

(a) For affected sources subject to the work practice standard or the management practices of a tune-up, you must conduct a performance tune-up according to paragraph (b) of this section and keep records as required in § 63.11225(c) to demonstrate continuous compliance. You must conduct the tune-up while burning the type of fuel (or fuels in the case of boilers that routinely burn two types of fuels at the same time) that provided the majority of the heat input to the boiler over the 12 months prior to the tune-up.

(b) Except as specified in paragraphs (c) through (f) of this section, you must conduct a tune-up of the boiler biennially to demonstrate continuous compliance as specified in paragraphs (b)(1) through (7) of this section. Each biennial tune-up must be conducted no more than 25 months after the previous tune-up. For a new or reconstructed boiler, the first biennial tune-up must be no later than 25 months after the initial startup of the new or reconstructed boiler.

(1) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may delay the burner inspection until the next scheduled

unit shutdown, not to exceed 36 months from the previous inspection). Units that produce electricity for sale may delay the burner inspection until the first outage, not to exceed 36 months from the previous inspection.

(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 (you may delay the inspection until the next scheduled unit shutdown, not to exceed 36 months from the previous inspection). Units that produce electricity for sale may delay the inspection until the first outage, not to exceed 36 months from the previous inspection.

(4) Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any nitrogen oxide requirement to which the unit is subject.

(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.

(6) Maintain on-site and submit, if requested by the Administrator, a report containing the information in paragraphs (b)(6)(i) through (iii) of this section.

(i) 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.

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

(iii) The type and amount of fuel used over the 12 months prior to the tune-up of the boiler, but only if the unit was physically and legally capable of using more than one type of fuel during that period. Units sharing a fuel meter may estimate the fuel use by each unit.

(7) If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 days of startup.

(g) If you own or operate a boiler subject to emission limits in Table 1 of this subpart, you must minimize the boiler's startup and shutdown periods following the manufacturer's recommended procedures, if available. If manufacturer's recommended procedures are not available, you must follow recommended procedures for a unit of similar design for which manufacturer's recommended procedures are available. You must submit a signed statement in the Notification of Compliance Status report that indicates that you conducted startups and shutdowns according to the manufacturer's recommended procedures or procedures specified for a boiler of similar design if manufacturer's recommended procedures are not available."

The requirements of § 63.11223 Paragraph (a), (b), and (g) will be added to the permit.

§ 63.11224 Paragraphs (c), and (d) state, "What are my monitoring, installation, operation, and maintenance requirements?

(c) If you demonstrate compliance with any applicable emission limit through stack testing and subsequent compliance with operating limits, you must develop a site-specific monitoring plan according to the requirements in paragraphs (c)(1) through (4) of this section. This requirement also applies to you if you petition the EPA Administrator for alternative monitoring parameters under § 63.8(f).

(1) For each CMS required in this section, you must develop, and submit to the EPA Administrator for approval upon request, a site-specific monitoring plan that addresses paragraphs (c)(1)(i) through (iii) of this section. You must submit this site-specific monitoring plan (if requested) at least 60 days before your initial performance evaluation of your CMS.

(i) Installation of the CMS sampling probe or other interface at a measurement location relative to each affected unit such that the measurement is representative of control of the exhaust emissions (e.g., on or downstream of the last control device).

(ii) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems.

(iii) Performance evaluation procedures and acceptance criteria (e.g., calibrations).

(2) In your site-specific monitoring plan, you must also address paragraphs (c)(2)(i) through (iii) of this section.

(i) Ongoing operation and maintenance procedures in accordance with the general requirements of § 63.8(c)(1), (3), and (4)(ii).

(ii) Ongoing data quality assurance procedures in accordance with the general requirements of § 63.8(d).

(iii) Ongoing recordkeeping and reporting procedures in accordance with the general requirements of § 63.10(c), (e)(1), and (e)(2)(i).

(3) You must conduct a performance evaluation of each CMS in accordance with your site-specific monitoring plan.

(4) You must operate and maintain the CMS in continuous operation according to the site-specific monitoring plan.

(d) If you have an operating limit that requires the use of a CMS, you must install, operate, and maintain each CPMS according to the procedures in paragraphs (d)(1) through (4) of this section.

(1) The CPMS must complete a minimum of one cycle of operation every 15 minutes. You must have data values from a minimum of four successive cycles of operation representing each of the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CMS calibration, quality assurance, or maintenance activities are being performed, to have a valid hour of data.

(2) You must calculate hourly arithmetic averages from each hour of CPMS data in units of the operating limit and determine the 30-day rolling average of all recorded readings, except as provided in § 63.11221(c). Calculate a 30-day rolling average from all of the hourly averages collected for the 30-day operating period using Equation 3 of this section.

$$30 - day\ average = \frac{\sum_{i=1}^{n} H_{pvi}}{n} \quad (Eq. 3)$$

Where:

Hpvi	=	the hourly parameter value for hour
n	=	the number of valid hourly parameter values collected over 30 boiler operating days

(3) For purposes of collecting data, you must operate the CPMS as specified in § 63.11221(b). For purposes of calculating data averages, you must use all the data collected during all periods in assessing compliance, except that you must exclude certain data as specified in § 63.11221(c). Periods when CPMS data are unavailable may constitute monitoring deviations as specified in § 63.11221(d).
(4) Record the results of each inspection, calibration, and validation check."

The requirements of § 63.11224 Paragraphs (c) and (d) will be added to the permit.

§ 63.11225 Paragraph (a) states, "You must submit the notifications specified in paragraphs (a)(1) through (5) of this section to the administrator.

(1) You must submit all of the notifications in §§ 63.7(b); 63.8(e) and (f); and 63.9(b) through (e), (g), and (h) that apply to you by the dates specified in those sections except as specified in paragraphs (a)(2) and (4) of this section.
(2) An Initial Notification must be submitted no later than January 20, 2014 or within 120 days after the source becomes subject to the standard.
(3) If you are required to conduct a performance stack test you must submit a Notification of Intent to conduct a performance test at least 60 days before the performance stack test is scheduled to begin.
(4) You must submit the Notification of Compliance Status no later than 120 days after the applicable compliance date specified in § 63.11196 unless you own or operate a new boiler subject only to a requirement to conduct a biennial or 5-year tune-up or you must conduct a performance stack test. If you own or operate a new boiler subject to a requirement to conduct a tune-up, you are not required to prepare and submit a Notification of Compliance Status for the tune-up. If you must conduct a performance stack test, you must submit the Notification of Compliance Status within 60 days of completing the performance stack test. You must submit the Notification of Compliance Status in accordance with paragraphs (a)(4)(i) and (vi) of this section. The Notification of Compliance Status must include the information and certification(s) of compliance in paragraphs (a)(4)(i) through (v) of this section, as applicable, and signed by a responsible official.

(i) You must submit the information required in § 63.9(h)(2), except the information listed in § 63.9(h)(2)(i)(B), (D), (E), and (F). If you conduct any performance tests or CMS performance evaluations, you must submit that data as specified in paragraph (e) of this section. If you conduct any opacity or visible emission observations, or other monitoring procedures or methods, you must submit that data to the Administrator at the appropriate address listed in § 63.13.
(vi) The notification must be submitted electronically using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (www.epa.gov/cdx). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written Notification of Compliance Status must be submitted to the Administrator at the appropriate address listed in § 63.13.

(5) If you are using data from a previously conducted emission test to serve as documentation of conformance with the emission standards and operating limits of this subpart, you must include in the Notification of Compliance Status the date of the test and a summary of the results, not a complete test report, relative to this subpart."

§ 63.11225 Paragraph (b) states, "You must prepare, by March 1 of each year, and submit to the delegated authority upon request, an annual compliance certification report for the previous calendar year containing the information specified in paragraphs (b)(1) through (4) of this section. You must submit the report by March 15 if you had any instance described by paragraph (b)(3) of this section. For boilers that are subject only to the energy assessment requirement and/or a requirement to conduct a biennial or 5-year tune-up according to § 63.11223(a) and not subject to emission limits or operating limits, you may prepare only a biennial or 5-year compliance report as specified in paragraphs (b)(1) and (2) of this section.

(1) Company name and address.

(2) Statement by a responsible official, with the official's name, title, phone number, email address, and signature, certifying the truth, accuracy and completeness of the notification and a statement of whether the source has complied with all the relevant standards and other requirements of this subpart. Your notification must include the following certification(s) of compliance, as applicable, and signed by a responsible official:

(i) "This facility complies with the requirements in § 63.11223 to conduct a biennial or 5-year tuneup, as applicable, of each boiler."

(ii) For units that do not qualify for a statutory exemption as provided in section 129(g)(1) of the Clean Air Act: "No secondary materials that are solid waste were combusted in any affected unit."

(iii) "This facility complies with the requirement in §§ 63.11214(d) and 63.11223(g) to minimize the boiler's time spent during startup and shutdown and to conduct startups and shutdowns according to the manufacturer's recommended procedures or procedures specified for a boiler of similar design if manufacturer's recommended procedures are not available."

(3) If the source experiences any deviations from the applicable requirements during the reporting period, include a description of deviations, the time periods during which the deviations occurred, and the corrective actions taken.

(4) The total fuel use by each affected boiler subject to an emission limit, for each calendar month within the reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by you or EPA through a petition process to be a non-waste under § 241.3(c), whether the fuel(s) were processed from discarded non-hazardous secondary materials within the meaning of § 241.3, and the total fuel usage amount with units of measure."

§ 63.11225 Paragraph (c) states, "You must maintain the records specified in paragraphs (c)(1) through (7) of this section.

(1) As required in § 63.10(b)(2)(xiv), you must keep a copy of each notification and report that you submitted to comply with this subpart and all documentation supporting any Initial Notification or Notification of Compliance Status that you submitted.

(2) You must keep records to document conformance with the work practices, emission reduction measures, and management practices required by § 63.11214 and § 63.11223 as specified in paragraphs (c)(2)(i) through (vi) of this section.

(i) Records must identify each boiler, the date of tune-up, the procedures followed for tune-up, and the manufacturer's specifications to which the boiler was tuned.

(iv) For each boiler subject to an emission limit in Table 1 to this subpart, you must keep records of monthly fuel use by each boiler, including the type(s) of fuel and amount(s) used. For each new oil-fired boiler that meets the requirements of § 63.11210(e) or (f), you must keep records, on a monthly basis, of the type of fuel combusted.

(4) Records of the occurrence and duration of each malfunction of the boiler, or of the associated air pollution control and monitoring equipment.
(5) Records of actions taken during periods of malfunction to minimize emissions in accordance with the general duty to minimize emissions in § 63.11205(a), including corrective actions to restore the malfunctioning boiler, air pollution control, or monitoring equipment to its normal or usual manner of operation.
(6) You must keep the records of all inspection and monitoring data required by §§ 63.11221 and 63.11222, and the information identified in paragraphs (c)(6)(i) through (vi) of this section for each required inspection or monitoring.
(i) The date, place, and time of the monitoring event.
(ii) Person conducting the monitoring.
(iii) Technique or method used.
(iv) Operating conditions during the activity.
(v) Results, including the date, time, and duration of the period from the time the monitoring indicated a problem to the time that monitoring indicated proper operation.
(vi) Maintenance or corrective action taken (if applicable)."

§ 63.11225 Paragraph (d) states, "Your records must be in a form suitable and readily available for expeditious review. You must keep each record for 5 years following the date of each recorded action. You must keep each record on-site or be accessible from a central location by computer or other means that instantly provide access at the site for at least 2 years after the date of each recorded action. You may keep the records off site for the remaining 3 years."

§ 63.11225 Paragraph (e) states,
"(1) Within 60 days after the date of completing each performance test (as defined in § 63.2) required by this subpart, you must submit the results of the performance tests, including any associated fuel analyses, following the procedure specified in either paragraph (e)(1)(i) or (ii) of this section.
(i) For data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT Web site (https://www3.epa.gov/ttn/chief/ert/ert_info.html) at the time of the test, you must submit the results of the performance test to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (https://cdx.epa.gov/).) Performance test data must be submitted in a file format generated through the use of the EPA's ERT or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the EPA's ERT Web site. If you claim that some of the performance test information being submitted is confidential business information (CBI), you must submit a complete file generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT Web site, including information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAQPS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT or alternate file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph.

(ii) For data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT Web site at the time of the test, you must submit the results of the performance test to the Administrator at the appropriate address listed in § 63.13."

The requirements of § 63.11225 Paragraphs (a), (b), (c), (d), and (e) will be added to the permit.

40 CFR 63.7: Performance Testing Requirements

§ 63.7 Paragraph (a) states, "Applicability and performance test dates.

(2) Except as provided in paragraph (a)(4) of this section, if required to do performance testing by a relevant standard, and unless a waiver of performance testing is obtained under this section or the conditions of paragraph (c)(3)(ii)(B) of this section apply, the owner or operator of the affected source must perform such tests within 180 days of the compliance date for such source.

(ix) Except as provided in paragraph (a)(4) of this section, when an emission standard promulgated under this part is more stringent than the standard proposed (see § 63.6(b)(3)), the owner or operator of a new or reconstructed source subject to that standard for which construction or reconstruction is commenced between the proposal and promulgation dates of the standard shall comply with performance testing requirements within 180 days after the standard's effective date, or within 180 days after startup of the source, whichever is later. If the promulgated standard is more stringent than the proposed standard, the owner or operator may choose to demonstrate compliance with either the proposed or the promulgated standard. If the owner or operator chooses to comply with the proposed standard initially, the owner or operator shall conduct a second performance test within 3 years and 180 days after the effective date of the standard, or after startup of the source, whichever is later, to demonstrate compliance with the promulgated standard.

(3) The Administrator may require an owner or operator to conduct performance tests at the affected source at any other time when the action is authorized by section 114 of the Act."

The requirements of 40 CFR Part 63 Subpart A § 63.7 have not been added to the permit due to the requirements of 40 CFR Part 63 Subpart JJJJJJ being stricter.

§ 63.7 Paragraph (b) states, "Notification of performance test.

(1) The owner or operator of an affected source must notify the Administrator in writing of his or her intention to conduct a performance test at least 60 calendar days before the performance test is initially scheduled to begin to allow the Administrator, upon request, to review an approve the sitespecific test plan required under paragraph (c) of this section and to have an observer present during the test.

(2) In the event the owner or operator is unable to conduct the performance test on the date specified in the notification requirement specified in paragraph (b)(1) of this section due to unforeseeable circumstances beyond his or her control, the owner or operator must notify the Administrator as soon as practicable and without delay prior to the scheduled performance test date and specify the date when the performance test is rescheduled. This notification of delay in conducting the performance test shall not relieve the owner or operator of legal responsibility for compliance with any other applicable provisions of this part or with any other applicable Federal, State, or local requirement, nor will it prevent the

Administrator from implementing or enforcing this part or taking any other action under the Act."

The requirements of § 63.7 Paragraph (b) will be added to the permit.

§ 63.7 Paragraph (c) states, "Quality assurance program.

(1) The results of the quality assurance program required in this paragraph will be considered by the Administrator when he/she determines the validity of a performance test.

(2)

(i) Submission of site-specific test plan. Before conducting a required performance test, the owner or operator of an affected source shall develop and, if requested by the Administrator, shall submit a site-specific test plan to the Administrator for approval. The test plan shall include a test program summary, the test schedule, data quality objectives, and both an internal and external quality assurance (QA) program. Data quality objectives are the pretest expectations of precision, accuracy, and completeness of data.

(ii) The internal QA program shall include, at a minimum, the activities planned by routine operators and analysts to provide an assessment of test data precision; an example of internal QA is the sampling and analysis of replicate samples.

(iii) The performance testing shall include a test method performance audit (PA) during the performance test. The PAs consist of blind audit samples supplied by an accredited audit sample provider and analyzed during the performance test in order to provide a measure of test data bias. Gaseous audit samples are designed to audit the performance of the sampling system as well as the analytical system and must be collected by the sampling system during the compliance test just as the compliance samples are collected. If a liquid or solid audit sample is designed to audit the sampling system, it must also be collected by the sampling system during the compliance test. If multiple sampling systems or sampling trains are used during the compliance test for any of the test methods, the tester is only required to use one of the sampling systems per method to collect the audit sample. The audit sample must be analyzed by the same analyst using the same analytical reagents and analytical system and at the same time as the compliance samples. Retests are required when there is a failure to produce acceptable results for an audit sample. However, if the audit results do not affect the compliance or noncompliance status of the affected facility, the compliance authority may waive the reanalysis requirement, further audits, or retests and accept the results of the compliance test. Acceptance of the test results shall constitute a waiver of the reanalysis requirement, further audits, or retests. The compliance authority may also use the audit sample failure and the compliance test results as evidence to determine the compliance or noncompliance status of the affected facility. A blind audit sample is a sample whose value is known only to the sample provider and is not revealed to the tested facility until after they report the measured value of the audit sample. For pollutants that exist in the gas phase at ambient temperature, the audit sample shall consist of an appropriate concentration of the pollutant in air or nitrogen that can be introduced into the sampling system of the test method at or near the same entry point as a sample from the emission source. If no gas phase audit samples are available, an acceptable alternative is a sample of the pollutant in the same matrix that would be produced when the sample is recovered from the sampling system as required by the test method. For samples that exist only in a liquid or solid form at ambient temperature, the audit sample shall consist of an appropriate concentration of the pollutant in the same matrix that would be produced when the sample is recovered from the sampling system as required by the test method. An accredited audit sample provider (AASP) is an organization that has been accredited to prepare audit samples by an independent, third party accrediting body.

(A) The source owner, operator, or representative of the tested facility shall obtain an audit sample, if commercially available, from an AASP for each test method used for regulatory compliance purposes. No audit samples are required for the following test methods: Methods 3A and 3C of appendix A-3 of part 60 of this chapter; Methods 6C, 7E, 9, and 10 of appendix A-4 of part 60; Methods 18 and 19 of appendix A-6 of part 60; Methods 20, 22, and 25A of appendix A-7 of part 60; Methods 30A and 30B of appendix A-8 of part 60; and Methods 303, 318, 320, and 321 of appendix A of this part. If multiple sources at a single facility are tested during a compliance test event, only one audit sample is required for each method used during a compliance test. The compliance authority responsible for the compliance test may waive the requirement to include an audit sample if they believe that an audit sample is not necessary. "Commercially available" means that two or more independent AASPs have blind audit samples available for purchase. If the source owner, operator, or representative cannot find an audit sample for a specific method, the owner, operator, or representative shall consult the EPA Web site at the following URL, www.epa.gov/ttn/emc, to confirm whether there is a source that can supply an audit sample for that method. If the EPA Web site does not list an available audit sample at least 60 days prior to the beginning of the compliance test, the source owner, operator, or representative shall not be required to include an audit sample as part of the quality assurance program for the compliance test. When ordering an audit sample, the source owner, operator, or representative shall give the sample provider an estimate for the concentration of each pollutant that is emitted by the source or the estimated concentration of each pollutant based on the permitted level and the name, address, and phone number of the compliance authority. The source owner, operator, or representative shall report the results for the audit sample along with a summary of the emission test results for the audited pollutant to the compliance authority and shall report the results of the audit sample to the AASP. The source owner, operator, or representative shall make both reports at the same time and in the same manner or shall report to the compliance authority first and then report to the AASP. If the method being audited is a method that allows the samples to be analyzed in the field and the tester plans to analyze the samples in the field, the tester may analyze the audit samples prior to collecting the emission samples provided a representative of the compliance authority is present at the testing site. The tester may request, and the compliance authority may grant, a waiver to the requirement that a representative of the compliance authority must be present at the testing site during the field analysis of an audit sample. The source owner, operator, or representative may report the results of the audit sample to the compliance authority and then report the results of the audit sample to the AASP prior to collecting any emission samples. The test protocol and final test report shall document whether an audit sample was ordered and utilized and the pass/fail results as applicable.

(iv) The owner or operator of an affected source shall submit the site-specific test plan to the Administrator upon the Administrator's request at least 60 calendar days before the performance test is scheduled to take place, that is, simultaneously with the notification of intention to conduct a performance test required under paragraph (b) of this section, or on a mutually agreed upon date.

(v) The Administrator may request additional relevant information after the submittal of a site-specific test plan."

The requirements of § 63.7 Paragraph (c) will be added to the permit.

40 CFR 64: Compliance Assurance Monitoring

§ 64.2 Paragraphs (a) through (a)(3) state, "General applicability. Except for backup utility units that are exempt under paragraph (b)(2) of this section, the requirements of this part shall apply to a pollutant-specific emissions unit at a major source that is required to obtain a part 70 or 71 permit if the unit satisfies all of the following criteria:

(1) The unit is subject to an emission limitation or standard for the applicable regulated air pollutant (or a surrogate thereof), other than an emission limitation or standard that is exempt under paragraph (b)(1) of this section;

(2) The unit uses a control device to achieve compliance with any such emission limitation or standard; and

(3) The unit has potential pre-control device emissions of the applicable regulated air pollutant that are equal to or greater than 100 percent of the amount, in tons per year, required for a source to be classified as a major source. For purposes of this paragraph, "potential pre-control device emissions" shall have the same meaning as "potential to emit," as defined in § 64.1, except that emission reductions achieved by the applicable control device shall not be taken into account."

While listed as the second step, the simplest first step in evaluating CAM for the 110 MMBtu Boiler is to consider (2) above and look at the control devices used. These include ultra-low NO_X burner, flue gas recirculation, and an oxidation catalyst. The ultra-low NO_X burner and flue gas recirculation for NO_X do not fall under the definition of a control devices in 40 CFR Part 64 § 64.1 which states in part:

"For purposes of this part, a control device does not include passive control measures that act to prevent pollutants from forming, such as the use of seals, lids, or roofs to prevent the release of pollutants, use of low-polluting fuel or feedstocks, or the use of combustion or other process design features or characteristics."

In the case of the 110 MMBtu Boiler, the ultra-low NO_X burner and flue gas recirculation prevent the creation of NO_X before it forms and are therefore not applicable to CAM. The oxidation catalyst is a control device for carbon monoxide and should therefore be evaluated further.

Tables 3, 4 and 5 of this memorandum show the potential to emit (PTE) for the 110 MMBtu boiler when fired on the three allowable fuels (No. 2 fuel oil, natural gas, and natural gas / landfill gas blend). The highest uncontrolled emission rate for carbon monoxide is found for No. 2 fuel oil and a PTE of 48 tpy has been calculated. As a limit on No. 2 fuel oil use has been taken (1475 hours/yr), the highest calculated PTE would be:

$$\left(11\,\frac{lb}{hr} * 1{,}475\,\frac{hr}{yr}\right) + \left(4.1\,\frac{lb}{hr} * 7{,}285\,\frac{hr}{yr}\right) = 46{,}093.5\,\frac{lb}{yr} = 23.05\,\frac{ton}{yr}$$

As the maximum calculated PTE for carbon monoxide is less than the major source threshold of 100 ton/year, CAM is not applicable.

Other Considerations

7 DE Admin. Code 1144 Section 5.3 states, "Waste, landfill, or digester gases combusted in a generator on or after April 11, 2006 shall contain no more than ten grains total sulfur per 100 dry standard cubic feet (170 ppmv total sulfur) on a daily average. An alternative total sulfur limit for waste, landfill, or digester gases shall be allowed based upon a case-by-case determination."

7 DE Admin. Code 1144 is not applicable to the 110 MMBtu boiler, given that Regulation 1144 deals with the control of stationary generator emissions. However, the requirements of Section 5.3 are applicable to other emission units (CHP 1, CHP 2, and CHP 3) at the facility utilizing landfill gas, thus providing a regulatory basis for setting a limit on the sulfur content of this fuel, to ensure consistency across all emission units utilizing landfill gas. Therefore, the Departments is warranted in including this requirement under the provisions of 7 DE Admin. Code 1130 Section 6.1.1.

The landfill gas supplier's operating permit [**Permit: APC-2013/0005-OPERATION (Amendment 2)**] requires that the supplied landfill gas contain no greater than 150 ppm H_2S, and that measurements of the gas constituents (CH_4, O_2, H_2S, and CO_2) are recorded.

The following condition is being added for consistency with other emission units utilizing landfill gas and under the provisions of 7 DE Admin. Code 1130 Section 6.1.3.1.2. The condition will read, "The owner or operator shall require the landfill gas supplier to continually monitor fuel gas quality by analyzing for CH_4, CO_2, O_2, N_2 and sulfur via a permanently mounted gas chromatograph and/or equivalent equipment as it is delivered to the Atlas Point facility. Fuel gas quality data shall be made available to the Atlas Point facility at a minimum of once per month and upon request. The gas chromatograph and/or equivalent equipment used to analyze fuel gas quality shall be calibrated and maintained according to the manufacturer's specifications."

RECOMMENDATIONS

It is recommended that the attached Draft Permit be advertised and sent to EPA and affected states pursuant to the requirements of 7 DE Admin. Code 1102 Section 12.4 on October 29, 2023.

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pc: Dover File