Table of Contents for Bellefield Boiler Plant SIP Package
RACT 2 Case-by-Case Evaluation
Installation Permit No. 0047-I003

Pennsylvania Department of Environmental Protection
Bureau of Air Quality

RACT SIP COMPLETENESS CHECKLIST

TO BE FILLED IN BY REGIONAL STAFF AND SUBMITTED TO CENTRAL OFFICE

Facility Name: Bellefield Boiler Pland

RACT Plan Approval/Permit Number: Installation Permit No. 0047-I003

Plan Approval/Permit Issuance Date: April 14, 2020

TECHNICAL MATERIALS

Included	Not Included	Not Applicable	
☒	☐	☐	**Identification of all regulated (NOx and VOC) pollutants affected by the RACT plan (Review memo and RACT Permit)**
☒	☐	☐	**Quantification of the changes in plan allowable emissions from the affected sources as a result of RACT implementation. (Review Memo)**
☐	☐	☒	**Rationale as to why applicable CTG or ACT regulation is not RACT for the facility. (Review Memo)**
☐	☐	☒	**Demonstration that the NAAQS, PSD increment, reasonable further progress demonstration, and visibility, as applicable, are protected if the plan is approved and implemented. (Review Memo)**
☐	☐	☒	**In the event of actual emission increase as a result of RACT SIP revision: Modeling information to support the proposed revision, including input data, output data, model used, ambient monitoring data used, meteorological data used, justification for use of offsite data (where used), modes of models used, assumptions, and other information relevant to the determination of adequacy of the modeling analysis. (Review Memo)**
☐	☐	☒	**Include evidence, where necessary that emission limitations are based on continuous emission reduction technology. (Review Memo)**
☒	☐	☐	**State in RACT PA/OP that expiration date shown in PA or OP is for state purposes. Either use the statement below or redact the expiration date on the permit.** **(Sample: The expiration date shown in this permit is for state purposes. For federal enforcement purposes the conditions of this operating permit which pertain to the implementation of RACT regulations shall remain in effect as part of the State Implementation Plan (SIP) until replaced pursuant to 40 CFR 51 and approved by the U.S. Environmental Protection Agency (EPA). The operating permit shall become enforceable by the U.S. EPA upon its approval of the above as a revision to the SIP.) (RACT Permit)**
☐	☐	☒	**Include evidence that the State has the necessary legal authority under State law to adopt and implement the RACT plan. (Reference of PA's Air Pollution Control Act (January 8, 1960, P.L. 2119, as amended and 25 PA Code Chapter 127 (NSR), and 25 PA Code Chapter 129 §§129.91 – 95 in RACT PA/OP). (Review memo or more likely operating permit)**

(Back)

☒	☐	☐	**State that independent technical and economic justification for RACT determination by the Department was performed. As long as you reviewed the companies proposal you may agree with it but that must be stated. (Review memo)**
☐	☐	☒	**Confidential Business Information excluded, highlighted or marked. Please also redact all checks from the application. (Review Memo, RACT Permit, RACT Plan by the company)**
☒	☐	☐	**Adequate compliance demonstration, monitoring, recordkeeping, work practice standards, and reporting requirements. (Review memo and RACT Permit)**

ADMINISTRATIVE DOCUMENTS

Attached	Not Attached	Not Applicable	
☒	☐	☐	**Signed copy of final RACT Plan Approval/Operating Permit.**
☒	☐	☐	**Redacted copy of the RACT Plan Approval/Operating Permit. Reviewer should be able to read the redacted text. (We can do electronically if the PA/OP is uploaded in AIMS or available in pdf format). Make sure that the expiration date of the operating permit is redacted. SIPs do not expire.**
☒	☐	☐	**Signed Technical Support Document or Review Memorandum. The review memo should contain a discussion about previous case by case RACT determinations so that requirements can be compared**
☒	☐	☐	**Public Notice evidence: Include a copy of the actual published notice of the public hearing as it appeared in the local newspaper(s). The newspaper page must be included to show the date of publication. The notice must specifically identify by title and number each RACT regulation adopted or amended. A signed affidavit showing the dates of publication and the newspaper clipping is best. Next best is a copy of the newspaper clippings from all days the article was published. An email showing that the newspaper article was purchased is acceptable unless the EPA receives comments during their comment period stating that there is no proof of publication. The newspaper notice must say that the case by case requirements will be submitted to the EPA as an amendment to the SIP**
☒	☐	☐	**A separate formal certification duly signed indicating that public hearings were held. If no public hearings were held the review memo should state that.**
☒	☐	☐	**Public hearing minutes: This document must include certification that the hearing was held in accordance with the information in the public notice. It must also list the RACT regulations that were adopted, the date and place of the public hearing, and name and affiliation of each commenter. If there were no comments made during the notice period or at the hearing, please indicate that in the review memo.**
☒	☐	☐	**Comment and Response Document: A compilation of EPA, company, and public comments and Department's responses to these comments.**
☒	☐	☐	**Copy of RACT proposal, amendments, and other written correspondence between the Department and the facility.**

ALLEGHENY COUNTY HEALTH DEPARTMENT

AIR QUALITY PROGRAM
301 39th Street, Bldg. #7
Pittsburgh, PA 15201-1811

Reasonable Available Control Technology INSTALLATION PERMIT

Issued To:	**Bellefield Boiler Plant** **654 South Neville Street** **Pittsburgh, PA 15213-4080**	**ACHD Permit#:**	**0047-I003**
		Date of Issuance:	April 14, 2020
		Expiration Date:	~~(See Section III.12)~~

Issued By: Digitally signed by JoAnn Truchan, PE Date: 2020.04.15 15:45:55 -04'00'

JoAnn Truchan, P.E.
Section Chief, Engineering

Prepared By: Hafeez Ajenifuja Digitally signed by Hafeez Ajenifuja Date: 2020.04.15 16:19:18 -04'00'

Hafeez Ajenifuja
Air Quality Engineer

V. EMISSION UNIT LEVEL TERMS AND CONDITIONS

Pages 2 through 16 have been redacted.

A. NO_X Limits: Natural Gas Only Boilers 1, 5 & 8a

1. Restrictions:

~~a. The permittee shall continue to meet the conditions of the current Title V Operating Permit #0047 not otherwise affected by the revisions in this permit. [§2102.04.b.5; §2105.06.d]~~

~~b. Natural gas combustion from each boiler 1 and 5 shall not exceed the maximum potential usage of 70,476 scf in any one-hour period and 617.37 mmscf in any consecutive twelve-month period, based on a natural gas heat content of 1,050 Btu/scf. [§2103.12.h.1]~~

~~c. NO_X emissions from the following sources shall not exceed the limitations in Table V-A-1 below: [25 pa code §129.97(g)(1); §2102.04.b.5; §2105.06.d]~~

~~**TABLE V-A-1: NO_X Emission Limitations**~~

~~Process~~	~~Maximum Heat Input Capacity MMBtu/hr~~	~~Emission Limit** lbs/MMBtu~~	~~Hourly Emission Limit (lb/hr)~~	~~Annual Emission Limit (tons/year)*~~
~~Boiler 1~~	~~74~~	~~0.10~~	~~7.4~~	~~32.4~~
~~Boiler 5~~	~~74~~	~~0.10~~	~~7.4~~	~~32.4~~

~~*A year is defined as any consecutive 12-month period.~~
~~**Based on the PADEP presumptive RACT limit in 25 PA. Code, Chapter 129.97(g)(1)(i)).~~

d. NO_X emissions from boiler 8a shall not exceed the limitations in Table V-A-2 below: [25 Pa code §129.99; §2102.04.b.5; §2105.06.d]

TABLE V-A-2: NO_X Emission Limitations

Process	Maximum Heat Input Capacity MMBtu/hr	Emission Limit** lbs/MMBtu	Hourly Emission Limit (lb/hr)	Annual Emission Limit (tons/year)*
Boiler 8a, (Rental Package Boiler)	87	0.055	4.79	20.98

*A year is defined as any consecutive 12-month period.

2. Testing Requirements:

a. The permittee shall perform nitrogen oxides emissions testing while combusting natural gas on boilers no. 1 & 5 once every five years to demonstrate compliance with the emission limitations in condition V.A.1.c. Such testing shall be conducted in accordance with applicable U.S. EPA test methods 7 through 7E or other test methods approved by the Department, §2108.02 and Site Level Condition IV.14. [§2103.12.h.1; §2108.02; §2105.06.d; 25 Pa Code §129.99; 25 Pa Code §129.100]

~~b.~~ ~~The Department reserves the right to require additional emissions testing sufficient to assure compliance with the terms and conditions of this permit. Such testing shall be performed in accordance with Article XXI §2108.02. [§2103.12.h.1]~~

3. Monitoring Requirements

~~a.~~ ~~The permittee shall monitor and inspect the boilers weekly to insure the physical integrity of the boilers and associated equipment and to make sure the boilers are being operated and maintained properly. Steam load and natural gas usage shall be monitored and recorded to fulfill the recording requirements of V.A.4.a below. [§2105.06; §2103.12.i]~~

b. The permittee shall provide Department approved instrumentation to monitor the oxygen content, CO and NO_X of the boilers exhaust on a monthly basis during operation. The oxygen content of the flue gas shall be monitored to within 3% of the measured value and be recorded to the nearest 0.1%, to ensure that the subject boilers are being operated and maintained properly. The instrumentation shall be maintained in good working condition at all times and be easily accessible. [§2103.12.i; §2105.06; 25 Pa Code §129.100]

4. Record Keeping Requirements:

a. The permittee shall keep and maintain the following data for the boilers: [§2105.06; §2103.12.j; §2103.12.h.1; 25 Pa Code §129.100]:

1) Type and amount of fuel combusted (MMscf of natural gas/day and monthly total natural gas combusted);
2) Steam load (lbs/hr, lbs/day; average daily steam load for each month);
3) Cold starts (date, time and duration of each occurrence);
4) Total operating hours, (hours/day, monthly and 12-month); and
5) Records of operation, maintenance, inspection, calibration and/or replacement of combustion equipment (e.g. burner replacement, flame pattern adjustments, and air-to-fuel ratios).

~~b.~~ ~~The permittee shall record all instances of non-compliance with the conditions of this permit upon occurrence along with corrective action taken to restore compliance. [§2105.06; §2103.12.j; §2103.12.h.1]~~

c. All records required under this section shall be maintained by the permittee for a period of five years following the date of such record. These records shall be made available to the Department upon request for inspection and/or copying. [§2105.06; §2103.12.j.2; §2103.12.h.1; 25 Pa Code §129.100(i)]

5. Reporting Requirements:

a. The permittee shall submit semi-annual reports to the Department in accordance with General Condition III.15. The reports shall contain all required information for the time period of the report: [§2105.06; §2103.12.k.1; 25 Pa Code §129.100]

1) Type and amount of fuel combusted (Monthly and 12-month);
2) Steam load (average daily steam load for each month);
3) Cold starts (date, time and duration of each occurrence);
4) Total operating hours.

~~b. The permittee shall report instances of non-compliance as required to be recorded by V.A.4.b. [§2103.12.k]~~

~~c. Reporting instances of non-compliance does not relieve the permittee of the requirement to report breakdowns in accordance with Site Level Condition IV.8, if appropriate. [§2103.12.k]~~

~~**6. Work Practice Standard:**~~

~~None except as provided elsewhere.~~

~~**7. Additional Requirements:**~~

~~None except as provided elsewhere.~~

B. NO_X Limits: Natural Gas Boiler 3, 6 & 7 & No.2 Fuel Oil for Emergencies.

1. Restrictions:

~~a. The permittee shall continue to meet the conditions of the current Title V Operating Permit #0047not otherwise affected by the revisions in this RACT permit. [§2102.04.b.5; §2105.06.d]~~

b. The annual capacity factor for Boiler 3 shall not exceed 50% during any consecutive twelve-month period. The annual average heat input to the natural gas burner in Boiler No.3 shall not exceed 64 MMbtu/hr or 560,640 MMbtu/yr, based on a natural gas heat content of 1,050 BTU/ft^3. Bellefield shall determine compliance with this condition by maintaining records of natural gas use for the burner. (2105.06.d; §2103.12.h.1; 25 Pa Code §129.99)

~~c. Natural gas combustion from boilers 3 and 7 shall not exceed the maximum potential usage in condition V.B.1.g, Table V-B-1 based on a natural gas heat content of 1,050 Btu/scf. [§2103.12.h.1]~~

d. Boiler no. 7 annual capacity factor shall not exceed 39% during any consecutive twelve-month period when firing natural gas. [§2105.06.d; 25 Pa Code §129.99]

e. Boiler no.7 shall be equipped with low NO_X burners that meet the emission limitation in condition V.B.1.f below. [§2105.06.d; 25 Pa Code §129.99]

f. The permittee shall not operate boiler No. 7 unless a NO_X Continuous Emission Monitoring (CEM) system is present at all times and properly operated and maintained according to 40 CFR 60, Subpart Db [§2105.06.d; §2103.12.a.2.B; 25 Pa Code §123.51; 25 Pa Code §129.99]

g. NO_X Emissions from the following sources when firing Natural Gas shall not exceed the limitations in Table V-B-1 below: [25 Pa code §129.99; §2102.04.b.5; §2105.06.d; §2103.12.h.1; §60.44b(a)(1)]

TABLE V-B-1: NO_X Emission Limitations Firing Natural Gas

Process	Maximum Heat Input Capacity MMBtu/hr	Natural Gas*** Usage	Emission Limit lbs/MMBtu	Hourly Emission Limit (lb/hr)	Annual Emission Limit (tons/year)*
Boiler 3**	128	121,905 Scf/hr 533.94 MMcf/yr	0.20	25.60	56.06
Boiler 7**	188	179,048 Scf/hr 609 MMscf/yr	0.14	26.32	44.74

*A year is defined as any consecutive 12-month period.
**Based on a case-by-case and 2012 stack test and 2014 CEM test for boiler 7 when combust natural gas
****Based on NG heating content of 1050 Btu/scf

~~h. Natural gas combustion from boiler 6 shall not exceed the maximum potential usage of 170,467 scf in any-one-hour period and 1,494 mmscf in any consecutive twelve-month period, based on a natural gas heat content of 1,050 Btu/scf. [§2103.12.h.1]~~

~~i.~~ ~~NO_X emissions from boiler 6 shall not exceed the limitations in Table V-B-2 below: [25 Pa code §129.97(g)(1); §2102.04.b.5; §2105.06.d]~~

~~TABLE V-B-2: NO_X Emission Limitations Firing Natural Gas~~

~~Process~~	~~Maximum Heat Input Capacity MMBtu/hr~~	~~Emission Limit lbs/MMBtu**~~	~~Hourly Emission Limit (lb/hr)~~	~~Annual Emission Limit (tons/year)*~~
~~Boiler 6~~	~~179~~	~~0.10~~	~~17.90~~	~~78.40~~

~~*A year is defined as any consecutive 12-month period.~~
~~**Based on the PADEP presumptive RACT limit in 25 PA. Code, Chapter 129.97(g)(1)(i)).~~

~~j.~~ ~~The maximum allowable fuel oil usage, which is based on the annual capacity factor of 4.91% for Boilers Nos. 3, 6 & 7 during any consecutive twelve-month period shall not exceed the limits shown in Table V-B-3 below, when firing No. 2 fuel oil. [25 Pa Code §129.97(c); §2105.06.d]~~

~~k.~~ ~~All fuel oil combusted shall meet current ASTM specifications for no. 2 fuel oil and have a maximum sulfur content of 0.05% by weight at all times [§60.42b(j)(2); §2105.06.d]~~

~~l.~~ ~~Boiler no. 3, 6 & 7 annual capacity factor shall not exceed 4.91% during any consecutive twelve-month period when firing No. 2 fuel oil. [25 Pa Code §129.97(c)(7); §2105.06.d]~~

~~m.~~ ~~NO_X Emissions from the following sources when firing No. 2 fuel oil for emergencies shall not exceed the limitations in Table V-B-2 below: [25 Pa code §129.97(c); §2102.04.b.5; §2105.06.d; §2103.12.h.1]~~

~~TABLE V-B-3: NO_X Emission Limitations Firing Fuel Oil~~

~~Process~~	~~Maximum Heat Input Capacity MMBtu/hr~~	~~No. 2 Fuel Oil Usage~~	~~Emission Limit lbs/MMBtu~~	~~Hourly Emission Limit (lb/hr)~~	~~Annual Emission Limit (tons/year)*~~
~~Boiler 3~~	~~119~~	~~850 gal/hr~~ ~~365,500 gal/yr~~	~~0.63~~	~~74.97~~	~~16.12~~
~~Boiler 6**~~	~~179~~	~~1,280 gal/hr~~ ~~550,400 gal/yr~~	~~0.28~~	~~50.12~~	~~10.78~~
~~Boiler 7~~	~~188~~	~~1,340 gal/hr~~ ~~567,200 gal/yr~~	~~0.20~~	~~37.60~~	~~8.08~~

~~*A year is defined as any consecutive 12-month period.~~

2. Testing Requirements:

a. The permittee shall perform nitrogen oxides emissions testing while combusting natural gas on boiler no. 3 & 6 once every five years to demonstrate compliance with the emission limitations in condition V.B.1.g and V.B.1.i. Such testing shall be conducted in accordance with applicable U.S. EPA test methods 7 through 7E or other test methods approved by the Department, Article XXI §2108.02 and Site Level Condition IV.14. [25 Pa Code §129.99; 25 Pa Code §129.100; §2103.12.h.1; §2108.02; 25§2105.06.d]

b. The permittee shall perform Relative Accuracy Test Audits (RATA) of the boiler no. 7 NO_X CEMS as specified in 25 PA Code §§139.101 - 139.111 to determine compliance with the boiler

7 emission limitations in condition V.B.1.f. [§2108.03; §2105.06.d; 25 Pa Code §129.99; 25 Pa Code §129.100]

~~c.~~ ~~The Department reserves the right to require additional emissions testing sufficient to assure compliance with the terms and conditions of this permit. Such testing shall be performed in accordance with Article XXI §2108.02. [§2103.12.h.1]~~

3. Monitoring Requirements

~~a.~~ ~~The permittee shall monitor and inspect the boilers weekly to insure the physical integrity of the boilers and associated equipment and to make sure the boilers are being operated and maintained properly. Steam load and natural gas usage shall be monitored and recorded to fulfill the recording requirements of V.B.4.a below. [§2105.06; §2103.12.i]~~

b. The permittee shall provide Department approved instrumentation to monitor the oxygen content, CO and NO_X of the boilers exhaust on a monthly basis during operation. The oxygen content of the flue gas shall be monitored to within 3% of the measured value and be recorded to the nearest 0.1%, to ensure that the subject boilers are being operated and maintained properly. The instrumentation shall be maintained in good working condition at all times and be easily accessible. [§2103.12.i; §2105.06; 25 PA Code §129.100]

4. Record Keeping Requirements:

a. The permittee shall keep and maintain the following data for the boilers: [§2105.06; §2103.12.j; §2103.12.h.1; 25 Pa Code §129.100]
   1) Type and amount of fuel combusted (MMscf of natural gas/day and monthly total natural gas combusted);
   2) Steam load (lbs/hr, lbs/day; average daily steam load for each month);
   3) Cold starts (date, time and duration of each occurrence);
   4) Total operating hours, (hours/day, monthly and 12-month);
   5) Records of operation, maintenance, inspection, calibration and/or replacement of combustion equipment (e.g. burner replacement, flame pattern adjustments, and air-to-fuel ratios); and

~~b.~~ ~~The permittee shall record all instances of non-compliance with the conditions of this permit upon occurrence along with corrective action taken to restore compliance. [§2105.06; §2103.12.j; §2103.12.h.1]~~

~~c.~~ ~~All records required under this section shall be maintained by the permittee for a period of five years following the date of such record. These records shall be made available to the Department upon request for inspection and/or copying. [§2105.06; §2103.12.j.2; §2103.12.h.1; 25 Pa Code §129.100(i)]~~

~~**5. Reporting Requirements:**~~

~~a.~~ ~~The permittee shall submit semi-annual reports to the Department in accordance with General Condition III.15. The reports shall contain all required information for the time period of the report: [§2105.06; §2103.12.k.1]~~

   ~~1) Type and amount of fuel combusted (Monthly and 12-month);~~
   ~~2) Steam load (average daily steam load for each month);~~

~~3) Cold starts (date, time and duration of each occurrence);~~
~~4) Total operating hours.~~

~~b. Report instances of non-compliance as required to be recorded by V.B.4.b. [§2103.12.k]~~

~~c. Reporting instances of non-compliance does not relieve the permittee of the requirement to report breakdowns in accordance with Site Level Condition IV.8, if appropriate. [§2103.12.k]~~

~~**6. Work Practice Standard:**~~

~~None except as provided elsewhere.~~

~~**7. Additional Requirements:**~~

~~None except as provided elsewhere.~~

Pages 24 through 26 have been redacted.

ALLEGHENY COUNTY HEALTH DEPARTMENT
AIR QUALITY PROGRAM

April 14, 2020

SUBJECT: **Reasonable Available Control Technology (RACT II) Determination**
Bellefield Boiler Plant
4400 Forbes Avenue, Pittsburgh
Pittsburgh, PA 15213-4080
Allegheny County

Installation Permit No. 0047-I003

TO: JoAnn Truchan, P.E.
Section Chief, Engineering

FROM: Hafeez Ajenifuja
Air Quality Engineer

I. Executive Summary

Bellefield Boiler Plant is defined as a major source of NO_X emissions and was subjected to a Reasonable Available Control Technology II (RACT II) review by the Allegheny County Health Department (ACHD) required for the 1997 and 2008 Ozone National Ambient Air Quality Standard (NAAQS). The findings of the review established that technically and financially feasible RACT would result in the following emissions changes, summarized below.

Table 1 Technically and Financially Feasible Control Options Summary for NO_X

Unit ID	Emissions Unit	Financially Feasible Control Option	Current PTE RACT I, NOx TPY	RACT Reduction	Revised NO_X PTE	Annualized Control Cost ($/yr)	Cost Effectiveness ($/ton NO_X removed)
B001	Boiler 1	Presumptive	376	343.60	32.40	$0	$0
B003	Boiler 3	case-by-case (when combusting NG)	242	169.82	72.18	$226,000	$8,100
B005	Boiler 5	Presumptive	261	228.60	32.40	$0	$0
B006	Boiler 6, Package Boiler	Presumptive	191	101.82	89.18	$0	$0
B007	Boiler 7, Package Boiler	case-by-case (when combusting NG)	65	12.18	52.82	$489,000	$18,300
B008a	Boiler 8a, Package Boiler	case-by-case	0	0	20.98	$0	$0
Total			**1135**	**843.84**	**299.96**	**$935,000**	**$26,400**

These findings are based on the following documents:

- RACT analysis performed by ERG (0047-2015-02-17ract.pdf)
- RACT analysis performed by Bellefield Boiler Plant (0047r2015-01-30.pdf)
- BACT analysis performed by Bellefield Boiler Plant (see Application for Permit No. 0047-I003 dated 6/30/2017

II. Regulatory Basis

ACHD requested all major sources of NO_X (potential emissions of 100 tons per year or greater) and all major sources of VOC (potential emissions of 50 tons per year or greater) to reevaluate NO_X and/or VOC RACT for incorporation into Allegheny County's portion of the PA SIP. This document is the result of ACHD's determination of RACT for Bellefield Boiler Plant based on the materials submitted by the subject source and other relevant information.

III. Facility Description

Bellefield Boiler Plant is a captive steam generation facility located on S. Neville Street in the Oakland section of Pittsburgh, PA and it supplies steam for heating to institutional sites in that area. The plant is composed of six (6) boilers emitting from one stack. All the boilers fire natural gas as their primary fuel.

The boilers have the capacity to fire no. 2 fuel oil with sulfur content of 0.05% (500 ppm) at times of emergency, including natural gas curtailment and natural gas supply interruption, and during maintenance, periodic testing and startups except for boilers 1, 5 and 8a, which do not have the capability to fire fuel oil. Boilers 3, 6 and 7 emergency fuel oil usage will be based on an annual capacity factor of 4.91%. The facility also has two (2) oil fired emergency generators rated at 771 hp (5.4 MMbtu/hr) each. On December 19th, 1996 the facility entered into a consent decree with the Department to meet RACT I obligations under RACT Order No. 248.

Table 2	**Facility Sources Subject to Case-by-Case RACT II and Their Existing RACT I Limits**				
Source ID	**Description**	**Rating**	**NO_X PTE (TPY)**	**NO_X Presumptive Limit (RACT II)**	**NO_X Limit (RACT I)**
B003	Boiler 3	128 MMBtu/hr	167.80	0.10 lb/MMBtu	0.63 lb/MMBtu
B007	Boiler 7	188 MMBtu/hr	38	0.10 lb/MMBtu	0.20 lb/MMBtu

Table 3	Facility Sources Subject to the Presumptive RACT II per PA Code 129.97				
Source ID	**Description**	**Rating**	**NO_X PTE (TPY)**	**NO_X Presumptive Limit (RACT II)**	**NO_X Limit (RACT I)**
B001	Boiler 1-Uncontrolled	74 MMBtu/hr	32.40	0.10 lb/MMBtu	0.92 lb/MMBtu
B005	Boiler 5-Uncontrolled	74 MMBtu/hr	32.40	0.10 lb/MMBtu	0.59 lb/MMBtu
B006	Boiler 6, Package Boiler- Controlled	179 MMBtu/hr	78.40	0.10 lb/MMBtu	0.28 lb/MMBtu
B008a	Boiler 8a, (Rental Package Boiler)	87 MMBtu/hr	20.98	0.10 lb/MMBtu	NA
EG 1 & 2	Two (2) Emergency Generators	771 hp (5.4MMBtuhr), each	The permittee shall install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices.		

IV. RACT Determination

Bellefield Boiler Plant conducted stack testing on Boilers B-001, B-005 and B-006 in November 2016, with the boilers burning only natural gas. The stack testing indicated that these boilers could comply with the PADEP presumptive NO_X RACT limit of 0.10 lb/MMBtu. Therefore, BBP proposes that these three boilers have RACT II limits based on the presumptive RACT limit. No further analysis is required.

Boiler 8a NO_X in the Title V operating permit is restricted to 0.055 lb/MMBtu limits, which is more stringent than the presumptive RACT II of 0.10lb/MMBtu. Therefore, no further analysis is warranted.

The following table 4 below shows all possible NO_X control options:

Table 4 – NO_X Control Options

Category	Control Option
Combustion Optimization	Reduced air preheat (RAP)
	Combustion Optimization or Tune-up
	Low Excess Air (LEA)
Staged Combustion	Air Staging
	Fuel Staging
	Fuel Reburning
Additions To Combustion, Air or Fuel	Flue Gas Recirculation (FGR)
	Water / Steam Injection (WSI)
	Fuel Induced Recirculation (FIR)
Low-NO_x Burning	Low-NO_x Burner (LNB)
Post Combustion Control	Selective Catalytic Reduction (SCR)
	Selective Non-Catalytic Reduction (SNCR)

The potential Technically Feasible Control Options for Bellefield Boiler that were evaluated are detailed in Table 5 below.

Table 5	Technically Feasible NO_X Control Cost Comparisons		
Control Option		B003	B007
Low NOx Burners With Flue Gas Recirculation	tpy NO_X Removed	50	
	Cost	$226,000	
	$/ton	8,100	
Selective Catalytic Reduction + FGR	tpy NO_X Removed		93
	Cost		489,000
	$/ton		18,300

It was determined that SCR, LNB, and FGR are technically feasible for controlling boiler NO_X emissions for boilers No. 3 and 7. Tune-ups are considered technically feasible for boilers No. 3 and 7.

The cost proposal and installation of LNB + FGR in Boiler B-003 would cost $8,100 per ton of NO_X removed which is not economically infeasible. An annual tune-up is determined to be NOx RACT for Boiler B-003.

Boiler B-007 is already equipped with a low- NO_X burner with the capability of meeting a NO_X emission limit of 0.14 lb/MMBtu. The next technologically feasible control option is FGR + SCR and based on the costs shown in Table 5 ($18,300 tons/ NO_X removed) above, FGR + SCR is not a cost-effective technological option. However, the proposed NO_X RACT emission limits for Boiler B-007 is 0.14 lb/MMBtu, based on Boiler 7 CEM Relative Accuracy Test Audit (RATA), dated March 2, 2013 through February 28, 2014.

A number of the control options identified are not technically feasible for controlling NO_X from the boilers. This section presents the rationale explaining why each control option is not, technically feasible.

(a) Reduced Air Preheat
RAP is limited to stokers equipped with combustion air preheaters.[1] It is assumed Boilers No. 3 and 7 do not have air preheaters. Therefore, RAP is removed from further consideration.

(b) LEA

Boiler No. 3 was constructed in 1977. It was originally designed as coal-fired stoker chain-grate boilers and later retrofitted with natural gas burners. The boiler was originally designed to operate using relatively high excess air to ensure the coal was completely burned. The high amount of excess air was inherent in the original design; at the time it was considered an appropriate approach for enhancing complete combustion. Achieving low excess air conditions would require a fundamental redesign of each boiler. Therefore, LEA is considered technically infeasible for controlling NO_X emissions.

(c) Air Staging / Fuel Staging

The ICI ACT states that staged burner flame lengths tend to be longer than those of conventional burners. There is the possibility that flame impingement can occur on the furnace walls, resulting in tube failure and corrosion. Additionally, staged burners are often wider and longer than conventional burners, requiring significant modifications to existing water-walls and windboxes.[2]

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[1] Alternative Control Techniques (ACT) Document – NO_x Emissions from Industrial/ Commercial/ Institutional (ICI) Boilers (EPA-453/R-94-022). http://www.epa.gov/ttncatc1/dir1/icboiler.pdf, accessed January 12, 2015.
[2] Alternative Control Techniques (ACT) Document – NO_x Emissions from Industrial/ Commercial/ Institutional (ICI) Boilers (EPA-453/R-94-022). http://www.epa.gov/ttncatc1/dir1/icboiler.pdf, accessed January 12, 2015.

Although, specific information on boilers No. 3 and 7 internal sizes was not reviewed, it is expected that an older boiler would have these issues. Therefore, air staging and fuel staging are considered technically infeasible for controlling NO_X emissions.

(d) Fuel Re-burn

Reburning has been chiefly developed and applied in coal-fired boilers. Typically, natural gas is introduced downstream of the primary combustion chamber to create a secondary combustion zone. Natural gas is an attractive re-burn fuel because it is nitrogen-free. Boilers No.1 and No.5 are natural gas fired. Boilers No. 3 and 7 only burn fuel oil during emergencies, maintenance, and periodic testing.

Furthermore, it is likely boilers No. 3 and 7 do not have enough height nor residence time to create partial and then final combustion zones. Therefore, fuel re-burn is considered technically infeasible for controlling NO_X emissions.

(e) WSI

WSI has severe operational drawbacks, namely: reduced thermal efficiency, reduced steam production, and increased equipment corrosion. For these reasons, WSI has been primarily used on gas turbines where the reduction in thermal efficiency is much less than on a steam boiler. Therefore, WSI is considered technically infeasible for controlling NO_X emissions.

(f) FIR

EPA's RBLC (RACT-BACT-LAER Clearinghouse) shows only a single industrial sized natural gas-fired boiler equipped with a FIR for NO_X control over the last 10 years[3], and there is not enough information to further review this control technology for boilers 3 and 7. Therefore, FIR is removed from further consideration.

(g) SNCR

The appropriate SNCR temperature window is approximately 1600 to 2000°F. The exhaust temperature for boiler ranges from 275 to 500°F, which is much lower than the needed temperature of 1600 to 2000°F. Lower temperatures reduce the reaction rates and unreacted ammonia may slip through and be emitted from the stack. Therefore, SNCR is considered technically infeasible for controlling NO_X emissions.

V. <u>RACT Summary</u>

The RACT II limits listed in the Table 1 of this document above supersede the relevant conditions of Plan Approval Order and Agreement #248 (RACT I), issued December 19, 1996, when firing natural gas.

As shown in the Table 6 below, the proposed NOx emission rates for Boiler Nos. 1 through 7 are more stringent than the RACT I limit. The proposed limit for Boiler No. 8a is unchanged, and below the presumptive RACT limit. The draft RACT II IP3 will implement the NOx RACT II limits for each boiler. It also contains testing, monitoring, recordkeeping and reporting requirements for the NOx RACT II limits, and supersedes all of the 2001 NOx RACT I requirements. Upon approval of these emission limits, a complete Title V Operating Permit

[3] The following RBLC Codes were included in the search: 12.310 (Fuel Combustion; Industrial-Size Boilers/Furnaces size 100-250 MMBtu/hr; Natural Gas) and 13.310 (Fuel Combustion; Industrial-Size Boilers/Furnaces <100 and MMBtu/hr; Natural Gas.

renewal will be issued to incorporate all the existing applicable requirements along with the updated RACT II provisions for each boiler.

Table 6: RACT I vs. RACT II NOx Emission Limits

Unit Description	Equipment Status Since RACT I Order	RACT I NOx Emission Limit (lb/MMBtu) When Firing NG	RACT II NOx Emission Limit (lb/MMBtu) When Firing NG
Boiler B - 001	Active – Remains on Site	0.92	0.10
Boiler B-002	Shut Down	0.47	NA
Boiler B-003	Active – Remains on Site	0.63	0.20
Boiler B-004	Shut Down	0.47	NA
Boiler B-005	Active – Remains on Site	0.59	0.10
Boiler B-006	Active – Remains on Site	0.29	0.10
Boiler B-007	Active – Remains on Site	0.20	0.14
Boiler B-008a	Active – Remains on Site	0.055	0.055

Table 7: RACT II Emission Reduction Summary

Based on the findings in this RACT analysis, the Bellefield Boiler Plant facility emissions can be summarized as follows:

Table 7: NO_X Emission Summary

Boiler	Current PTE RACT I, NOx TPY	Revised PTE RACT II, NOx TPY (includes additional TPY when burning No. 2 fuel oil as applicable)	RACT Reduction
1	376	32.40	
3	242	56.06 + 16.12	
5	261	32.40	
6	191	78.40+10.78	
7	65	44.74 + 8.08	
8a	0	20.98	
Plant Total	**1,135**	**299.96**	**843.84**

As shown in Table 7 above, the new RACT II conditions reduce 843.03 tpy of NO_X from the Bellefield Boiler Plant facility.

VI. New and Revised RACT II IP Permit Conditions

1. Permit No. 0047-I003 Condition V.A.1.c:
2. Permit No. 0047-I003 Condition V.A.1.d
3. Permit No. 0047-I003 Condition V.B.1.f
4. Permit No. 0047-I003 Condition V.B.1.g
5. Permit No. 0047-I003 Condition V.B.1.i
6. Permit No. 0047-I003 Condition V.B.1.j
7. Permit No. 0047-I003 Condition V.C.1: The permittee shall install, maintain and operate the emergency generators in accordance with the manufacturer's specifications and with good operating practices. [25 PA Code §129.96 (c); 25 PA Code §129.99]

ALLEGHENY COUNTY HEALTH DEPARTMENT
Air Quality Program

SUMMARY OF PUBLIC COMMENTS AND DEPARTMENT RESPONSES ON THE PROPOSED ISSUANCE OF BELLEFIELD BOILER PLANT INSTALLATION PERMIT NO. 0047-I003

[Notice of the opportunity for public comment appeared in the legal section of the Pittsburgh Post-Gazette on December 19, 2019. The public comment period ended on January 22, 2020]

1. **<u>Comment:</u>** The Department should reconcile discrepancies in information in Table 1 and Table 5 of the Review Memorandum: The information regarding RACT emissions reductions and revised Potential to Emit (PTE) are inconsistent. On Table 1, the Department sets forth a total RACT reduction of 662.22 tpy (Table 5 states a RACT reduction of 623.23 tpy). On Table 1, the Department sets forth a revised PTE of 264.90 tpy (Table 5 states a total RACT reduction of 299.97 tpy). In addition, the Department provides little information on how these numbers were calculated, making it difficult to reconcile the discrepancies. Additional contextual information and actual calculations would provide meaningful information for the public. (1 Commenter)

   <u>Response:</u> The Department has revised Table 5 (currently Table 7) to reflect the total NO_X RACT reduction of 843.84 tons/year. The initial 264.90 tons/year in Table 1 of the draft Technical Support Document is the new total RACT NO_X emissions for boilers 1, 3, 5, 6, 7 and 8a when combusting Natural gas. The Tables 1 and 7 revised NO_X limit of 299.97 tons per year is the total NO_X limit for the entire facility and includes limits (16.12 tpy, 10.78 tpy, and 8.1 tpy) from boilers 3, 6 and 7 when combusting fuel oil during emergency period. Section IV of the Technical Support Document (TSD) highlights how the new NO_X RACT limit was calculated.

2. **<u>Comment:</u>** ACHD must evaluate all technically feasible control options for Boilers 3 and 7: In its RACT determination, ACHD found that five of the seven sources, specifically Boilers 1, 5, 6, and 8a and Emergency Generators 1 and 2 are subject to RACT requirements established by 25 Pa. Code §129.97. It appears from the TSD that ACHD evaluated only one control option for the remaining two sources, Boiler 3 and Boiler 7. Specifically, for Boiler 3 ACHD evaluated the cost-effectiveness of the "Low NO_X Burners with Flue Gas Recirculation" control option. For Boiler 7, ACHD evaluated the cost-effectiveness of the "Selective Catalytic Reduction + FGR" control option but not the cost-effectiveness of the seven other identified control options for both Boiler 3 and Boiler 7. It is not clear why ACHD identified eight potential control options for each boiler but only evaluated one such control option for each boiler in terms of cost-effectiveness. If any of the other identified control options are technically-feasible for Boilers 3 and 7, ACHD must evaluate whether such control options satisfy Article XXI's definition of RACT. If ACHD determines that any such control option is RACT for either (or both) Boiler 3 and Boiler 7, the Facility must be required to implement it. (1 Commenter)

   <u>Response:</u> Table 4 is a generic table for the Technically Feasible NO_X Cost Control options that should only include any technically feasible cost control for a source. The Department only evaluated one control option for Boiler 3 and Boiler 7 because there are no other technically feasible control options for the two (2) boilers due to the age and original design of the boiler as a coal-fired stoker boiler. The Department has revised the table to only include the technically feasible control options. See response to comments #14, #15 and #16 below.

3. **Comment:** It is not clear that ACHD considered all of the factors required by Article XXI's definition of "RACT" in making its determinations for Boilers 3 and 7. Specifically, it does not appear that ACHD considered the necessity of obtaining emission reductions, the social and economic impact of such reductions, the economic impact of reductions on any party other than the Facility's operator, or other means for attaining and maintaining the 2008 NAAQS for ozone. ACHD's RACT analysis for Boilers 3 and 7 should incorporate all of the factors in Article XXI's definition of "RACT", and its RACT determination for the Facility should be revised based on that re-analysis, if necessary. (1 Commenter)

   Response: Pursuant to 44 FR 53762; September 17, 1979, RACT is defined as the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility. RACT for a particular source is determined on a case-by-case basis, considering the technological and economic circumstances of the individual source. In addition, the facility has made all attempts to attain and maintain the 2008 NAAQS for ozone considering all available technological and economic feasibility. The NAAQS, as well as the presumptive RACT limits already incorporate those "social and economic" impacts on the community at large, as defined in Article XXI.

4. **Comment:** TSD, Section III, Facility Description: The 2nd to last sentence in the first paragraph should be revised as follows: "Boilers 3, 6, and 7 emergency fuel oil usage will be based on an annual capacity factor of 4.91%~~, which is 430 hours/year~~". See comment #7 below for details (1 Commenter)

   Response: The Department made the requested change.

5. **Comment:** TSD, Table 3: For Boiler 8a, ACHD's should note in either the label or footnote that Boiler 8a is a rental boiler. (See comment #8 below for details). (1 Commenter)

   Response: The Department has made the requested change.

6. **Comment:** TSD, Section IV: Please correct typo "Plant" in 1st sentence of first paragraph. (1 Commenter)

   Response: The Department made the requested change.

7. **Comment:** Section II, Facility Description: The 2nd last sentence in the first paragraph should be revised as follows: "Boilers 3, 6, and 7 emergency fuel usage will be based on annual capacity factor of 4.91%~~, which is 430 hours/year~~". This sentence and condition V.B.1.g. on Page 20 sets a limit on the number of hours Boilers 3, 6, and 7 may operate while combusting fuel oil in any 12-month period. The commenter requests that these limits be deleted. Instead of the number of hours, they request to add annual fuel usage restrictions for ensuring compliance with the annual fuel oil emission limits. The hours of operation were determined based on the assumption that the boilers would be operating on fuel oil at the annual capacity of 4.91% for all of those hours. In actuality, the boilers are operated at partial loads to match steam demand, and an operating hours restriction, in addition to the fuel usage restriction, limits boilers operating flexibility. Therefore, consistent with US EPA guidance in their White Paper on Streamlining Title V Permits, the commenter requests that the annual operating hours restrictions be deleted and replaced with an annual fuel oil combustion restriction. (1 Commenter)

   Response: The Department made the requested change.

8. **<u>Comment:</u>** Table II-1 Emission Unit Identification: In the last row, please add a note indicating "**Rental** Package Boiler" for B-008a. Boiler 8a is a rental package boiler, and the Supervising Committee would like to retain the flexibility to have the boiler on-site intermittently, as needed. Any boiler they rent would continue to comply with all of the permit conditions. (1 Commenter)

   <u>Response:</u> The Department made the requested change.

9. **<u>Comment:</u>** Condition V.A.1.d, Table V-A-2, NO_X Emission Limitations: please add a note indicating "Rental" Boiler 8a in the table. (1 Commenter)

   <u>Response:</u> The Department made the requested change.

10. **<u>Comment:</u>** Condition V.B.1.g., please revise as follows: "**The maximum allowable fuel oil usage, which is based on the annual capacity factor of 4.91% for** ~~The permittee shall not operate or allow to be operated~~ Boiler Nos. 3, 6, and 7 ~~for more than 430 hours~~ during any consecutive twelve-month period **shall not exceed the limits shown in Table V-B-2 below**, when firing No. 2 fuel oil [25 PA Code §129.96(c); §2105.06.d]" (1 Commenter)

    <u>Response:</u> The Department made the requested change.

11. **<u>Comment:</u>** EPA has previously SIP approved RACT I for Bellefield Boiler in 2001 (40 CFR 52.2063 (c)(177)(i)(B)(3)). ACHD must clearly identify those RACT I units, cross-index them with the current units at Bellefield Boiler and indicate which units have shutdown, been modified or remain. As required under the Clean Air Act §110(l), ACHD must provide an evaluation and comparison of the RACT II vs. RACT I requirements to ensure that there is no backsliding. Further, if the RACT I requirements still apply, ACHD should clearly state this in their review memo and ensure that the redacted permit provided for the SIP revision includes those applicable RACT I provisions. If, instead, the RACT I provisions are being superseded by RACT II, ACHD should clearly indicate this. (1 Commenter)

    <u>Response:</u> The Table below shows a comparison of the previously SIP-approved RACT I NO_X emission limits for Bellefield Boilers in 2001 (40 CFR 52.2063 (c)(177)(i)(B)(3)), and the proposed RACT II requirements. This NO_X RACT II emission limits supersede RACT I limit for the active boilers that remain on-site, when firing natural gas.

    As shown in the Table 1 below, the proposed NO_X emission rates for Boiler Nos. 1 through 7 are more stringent than the RACT I limit. The proposed limit for Boiler No. 8a is unchanged, and below the presumptive RACT limit. Therefore, no backsliding would occur.

    The draft RACT II IP3 will implement the NO_X RACT II limits for each boiler. It also contains testing, monitoring, recordkeeping and reporting requirements for the NOx RACT II limits, and supersedes all of the 2001 NO_X RACT I requirements. Upon approval of these emission limits, a complete Title V Operating Permit renewal will be issued to incorporate all the existing applicable requirements along with the updated RACT II provisions for each boiler.

Table 1: RACT I vs. RACT II NO_X Emission Limits

Unit Description	Equipment Status Since RACT I Order	RACT I NO_X Emission Limit (lb/MMBtu) When Firing NG	RACT II NO_X Emission Limit (lb/MMBtu) When Firing NG
Boiler B - 001	Active – Remains on site	0.92	0.10
Boiler B-002	Shut Down	0.47	NA
Boiler B-003	Active – Remains on site	0.63	0.20
Boiler B-004	Shut Down	0.47	NA
Boiler B-005	Active – Remains on site	0.59	0.10
Boiler B-006	Active – Remains on site	0.29	0.10
Boiler B-007	Active – Remains on site	0.20	0.14
Boiler B-008a	Active – Remains on site	0.055	0.055

12. **Comment:** Boiler 3 was restricted to an annual average heat input when burning natural gas to no more than 64 MMBtu/hr or 560,640 MMBtu/yr based on a natural gas heat content of 1,028 BTU/ft^3. The current draft IP does not specify such a restriction and the ACHD review memo does not explain why the lifting of this restriction is not backsliding under CAA §110(l). Boiler 7, which was also subject to 40 CFR Part 60 Subpart Db at the time of the RACT I approval, was required, as part of the RACT I approval, to meet all recordkeeping and reporting requirements of that Subpart. These include specific requirements for data that establishes the relationship between NO_X emissions and operations of the affected unit. ACHD must clearly indicate that these recordkeeping and reporting requirements continue to apply to Boiler 7. The RACT I requirements for all the boilers at Bellefield Boiler without CEMs (at the time, Boilers 1 through 6) including stack testing every 5 years. Boiler 7, required to install and operate a NO_X CEM, was required to maintain the CEM in accordance with 40 CFR Part 60 Subpart Db. The current IP for Bellefield Boiler only requires once every 5-year stack testing for boilers 1, 3, 5, and 6. Unless otherwise explained and justified, stack testing must be required for Boiler 8a for determination of RACT II compliance. In any case, ACHD must specify a compliance assessment method for Boiler 8a. (1 Commenter)

    Response: Condition V.B.1.b of the Draft Installation Permit (ACHD # 0047-I003) set a limit on Boiler No. 3's annual capacity factor to be restricted to 50% during any consecutive 12-month period, which is equivalent to the annual fuel usage limit. Boiler No. 3 will also continue to be restricted to an annual average heat input when burning natural gas to no more than 64 MMBtu/hr or 560,640 MMBtu/yr based on a natural gas heat content of 1,028 BTU/ft3. The existing annual fuel usage restriction of 560,640 MMBtu/yr and the annual average heat input capacity of Boiler No. 3 to not exceed 64 MMBtu/hr has been included in the RACT IP3.

    Boiler Nos. 7 and 8a are subject to the New Source Performance Standards (NSPS) in 40 CFR Part 60 Subpart Db and it has been referenced in the RACT II IP3 as it was in RACT I. The boilers will continue to be required to meet all restrictions, testing, recordkeeping and reporting requirements of that Subpart. These NSPS requirements are in Bellefield Boiler Plant's Title V Operating Permit

(ACHD Permit #0047, dated December 18, 2013), and will be incorporated into the upcoming renewal Title V permit. Boiler Nos. 7 and 8a are both required to operate NO_X CEMS (Title V Operating Permit Conditions V.E.3.a. and V.F.3.d.). The CEMS would also be used as the compliance basis for the NO_X RACT II limits. Upon approval of the RACT II NO_X emission limits, a complete Title V Operating Permit renewal will be issued to incorporate all the existing applicable requirements along with the updated RACT II provisions for each boiler.

13. **Comment:** Table 1 indicates that Boilers 3 and 7 are subject to case by case RACT II requirements while Boiler 8a is "no change." Please explain what "no change" means as it appears that RACT II requirements are applicable to this boiler. Further, if ACHD is determining that that Boiler 8a's NO_X emission restriction of 0.055 lbs/MMBtu is RACT II, this should be clearly stated and including in the IP.

    Response: Boiler 8a is subject to RACT II provisions with a NO_X emission limit of 0.055 lb/MMBtu, which is more stringent than the PADEP presumptive NO_X RACT emission rate of 0.10 lb NO_X /MMBtu (25 PA Code Chapter 129.97 (g)(1)(i)). The Technical Support Document (TSD) will be updated to clearly indicate that Boiler 8a's limit of 0.055 lb/MMBtu will meet the RACT II presumptive requirements. Therefore, the 0.055-lb/MMBtu limit incorporated into the Installation Permit remains unchanged.

14. **Comment:** There are currently Flue Gas Recirculation (FGR) controls on Boiler 6, low-NO_X burners (LNB) on Boiler 7 and LNB with the option for FGR on Boiler 8a. These controls are technically feasible for Boiler 3. However, the case by case RACT II evaluation for economic feasibility on Boiler 3 should include the consideration of LNB or FGR alone, and not just in combination. The current ACHD evaluation concludes that LNB with FGR (and also FGR with Selective Catalytic Reduction, SCR) is determined to be economically infeasible.

    Response: The NO_X RACT analysis in the Application for Permit No. 0047-I003, dated 6/30/2017, explains that installation of a low-NO_X burner (LNB) alone is not technically feasible. This is because Boiler 3, installed in 1977, was originally a coal-fired stoker boiler. The stoker chain grate was covered up in 2009, and the supplemental gas burners were then used as primary burners. The boiler was not designed as a gas-fired boiler, and it is not possible to control in-leakage of excess air. (LNB's rely on low excess air, staged combustion, and reduced combustion temperatures to reduce NO_X formation). Boiler 3 has ducts that can recirculate a portion of exhaust gases back to the combustion zone. This ductwork, which can function as flue gas recirculation (FGR), has been sealed off and is not currently in use. The operators report that it does not work very well. The LNB vendor included a cost to rehabilitate this FGR ductwork with his LNB cost estimate and guarantee. (Canon Boiler Works, Inc., Budgetary Cost Proposal, April 4, 2017) The LNB vendor was unwilling to provide a cost estimate and performance guarantee for an LNB unless the FGR was also rehabilitated to reduce some of the excess air. The LNB vendor was also unwilling to provide any NO_X reduction performance estimates for the FGR ductwork alone. Therefore, given the age and the original design of this boiler as a coal-fired stoker boiler, standalone implementation of either an LNB or FGR were considered technically infeasible.

15. **Comment:** For which boilers are the control options in Table 4 reflected? Each of these should be discussed and evaluated for Boilers 3, 7, and 8a (and perhaps Boiler 6), for which Bellefield is seeking a case-by-case RACT II determination.

    Response: Table 4 summarizes the technically feasible NO_X control options for Boilers 3 and 7. Section IV of the Technical Support Document (TSD) has been expanded to include the control options that were evaluated to determine technical feasibility for Boilers Nos. 3 and 7. However, it was determined that SCR, LNB, and FGR are technically feasible for controlling NO_X emissions for boilers No. 3 and 7. See response to comment #14 above and detailed information and evaluation of these options are in the case-by-case NO_X RACT analyses for Boilers 3 and 7 in the following documents, which are part of the Installation Permit application record.

- RACT analysis performed by ERG/ACHD Technical support document (0047-2015-02-17ract.pdf)
- RACT analysis performed by Bellefield Boiler Plant (0047r2015-01-30.pdf)
- BVACT analysis performed by Bellefield Boiler Plant (see Application for Permit No. 0047-I003 dated 6/30/2017)

Boilers 1, 5, 6 and 8a are subject to PA DEP NO_X presumptive RACT limits of 0.10 lbs/MMBtu when firing natural gas. Therefore, no further analysis is warranted.

16. **Comment:** ACHD proposes a NO_X RACT emission limit of 0.14 lb/MMBtu for Boiler 7 when burning natural gas based on a 2013/2014 CEM Relative Accuracy Test Audit (RATA). The RACT evaluation is a technical and economic feasibility analysis. Compliance information may be used as part of that analysis but is insufficient alone. ACHD's RACT II evaluation must discuss how NO_X emissions can be feasibly minimized when Boiler 7 is operating with its required LNB and potentially other NO_X controls.

    Response: The case-by-case NO_X RACT analyses for Boiler 7, in which all feasible NO_X controls are evaluated, are in the documents listed in the Response to Comment #15 above. Boiler 7 is equipped with an LNB. The original performance guarantee for this burner was 0.20 lb/MMBtu. Other technically feasible control options were eliminated as economically infeasible (see the ERG/ACHD Technical Support Document). With optimization of the existing LNB it was found that NO_X emissions could be lowered from 0.20 lb/MMBtu to 0.14 lb/MMBtu. Therefore, 0.14 lb/MMBtu was proposed as RACT. The test data referenced were provided to demonstrate that the existing LNB could comply with this lower NO_X emission rate. The Department has revised Section V of the Technical Support Document.

17. **Comment:** The presumptive RACT II requirements at 25 Pa Code §129.97(c)(7) do not apply to Boilers 3, 6, and 7 because they burn both natural gas and No. 2 fuel oil, which results in an annual capacity for each boiler greater than 5%. Therefore, it appears that a case-by-case RACT II determination is needed for these boilers (including Boiler 6) when burning fuel oil. The annual capacity factors applicable to Boiler 3 appear to conflict. For example, Boiler 3 is limited to no more than 50% annual capacity factor (because natural gas is not specified) in condition B.1.b but the same boiler when burning No. 2 fuel oil is limited to no more than 4.91% annual capacity factor in condition B.1.i. Please clarify the capacity or operating hours restrictions for all boilers. The NO_X emission limits proposed for Boiler 3, 6, and 7 are carry-overs from RACT I and are much higher than the presumptive NO_X limit of 0.12 lbs NO_X /MMBtu in 25 Pa Code §129.97(g)(1)(ii). For the case by case RACT II evaluation, ACHD must discuss and explain why these RACT I NO_X emission limitations are justified as RACT II.

    Response: Boilers 3, 6 and 7 have both natural gas and oil burners. There are separate burners for each fuel. In Boiler 3, the fuel oil burners have a slightly lower design heat input capacity (119 MMBtu/hr) than do the natural gas burners (128 MMBtu/hr). Natural gas and fuel oil are not mixed together and are not combusted at the same time. BBP's Title V Permit (ACHD Permit #0047) restricts oil combustion in these oil burners to periods of "emergency, including gas curtailment and gas supply interruption, and during maintenance, periodic testing and startups," not to exceed 500 hours per year. (Conditions V.B.1.g. and V.B.1.i.; V.D.1.g and V.D.1.k.; and V.E.1.e and V.E.1.j.)

Since oil can only be used for testing and when natural gas is not available, the separate oil burners in each of the three boilers are a “distillate-oil-fired combustion unit.” EPA appears to concur with this interpretation by referring to the presumptive NO_X RACT limit of 0.12 lb NO_X /MMBtu for these oil-fired burners in 25 PA Code Chapter 129.97(g)(1)(ii).

The RACT II Installation Permit would further restrict use of the emergency back-up oil in the oil burners to an annual capacity factor of less than five percent, equivalent to a restriction on fuel oil operations to no more than 430 hours annually in each of the three boilers. With this restriction, each boiler’s “distillate-oil-fired combustion unit” would qualify for the emission limit exemption in 25 PA Code Chapter 129.97(c)(7). 25 PA Code Chapter 129.97(c)(7) states that presumptive RACT for a fuel-burning unit with an annual capacity factor of less than five percent is to operate the source in accordance with the manufacturer’s specifications and with good operating practices. The oil burners in each boiler would continue to be operated on fuel oil only during emergencies (e.g. natural gas curtailment, gas supply interruption), maintenance (which cannot exceed 48 hours per year), and periodic testing and startups. NO_X RACT II would be met with good operating practices.

The Department has revised Condition V.B.1.b to read “Boiler no. 3 annual capacity factor shall not exceed 50% during any consecutive twelve-month period, when firing natural gas”

18. **Comment:** ACHD should double-check the figures in Table 1 as it appears that the current and revised PTE for Boiler 8a do not reflect the current limits in the draft installation permit. The RACT II potential emissions summary in Table 5 appears to be a comparison between current and post-RACT PTEs. As part of the RACT I and RACT II comparison, it is appropriate for ACHD to make a similar comparison between those PTEs. Including only those boilers that still remain at Bellefield Boiler, it appears that the RACT I plant-wide PTE was 1,135 TPY NO_X while the RACT II plant-wide PTE is 299.96 TPY NO_X. If accurate, ACHD may use the table below to indicate where the NO_X emission reductions are expected to occur.

    Response: The total for Boiler 8a in Table 1 of the RACT II Determination Review Memorandum is 20.98 tons per year, rather than 20.90 tons per year. The Department has revised Table 5 (currently Table 7) of the TSD to include the RACT I and RACT II comparison table.

Boiler	RACT I, NOx TPY	Boiler	RACT II, NO_X TPY (includes additional TPY when burning No. 2 fuel oil as applicable)
1	376	1	32.40
3	242	3	56.06 + 16.12
5	261	5	32.40
6	191	6	78.40+10.78
7	65	7	44.74 + 8.08
8a	0	8a	20.98
Plant Total	**1135**		**299.96**

19. **Comment:** ACHD should double check the figures in Tables V-B-1 and V-B-2 as it appears the maximum capacity identified for Boiler 3 is not the same in both tables. If the maximum capacity factor for Boiler 3 is different depending on whether natural gas or No. 2 fuel oil is used, please explain this in the review memo.

    Response: Tables V-B-1 and V-B-2 in the Draft Installation Permit are correct. Boiler 3 has one set of burners dedicated to natural gas combustion, and a separate set of burners for oil combustion (as an emergency back-up fuel only). The design heat input rate for the natural gas burners is 128 MBtu/hr. The design heat input rate for the oil burners is less, 119 MMBtu/hr. This has been clarified in the review memo.

List of Commenters

Name	Affiliation
Joseph Otis Minott, Esq. Christopher D. Ahlers, Esq.	Clean Air Council
John K. Baillie Senior Attorney	Group Against Smog & Pollution
Disha Shah, P.E.	CDM Smith Inc.
Cynthia H. Stahl, PhD. Air Protection Division	US EPA Region III

AIR QUALITY PROGRAM
301 39th Street, Bldg. #7
Pittsburgh, PA 15201-1811

Reasonable Available Control Technology INSTALLATION PERMIT

Issued To:	**Bellefield Boiler Plant** **654 South Neville Street** **Pittsburgh, PA 15213-4080**	**ACHD Permit#:**	**0047-I003**
		Date of Issuance:	------
		Expiration Date:	(See Section III.12)

Issued By:	_______________ **JoAnn Truchan, P.E.** **Section Chief, Engineering**	**Prepared By:**	_______________ **Hafeez Ajenifuja** **Air Quality Engineer**

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AMENDMENTS:

DATE	*SECTION(S)*

I. CONTACT INFORMATION

Facility Location:	**Bellefield Boiler Plant** 654 South Neville Street Pittsburgh, PA 15213-4080
Permittee/Owner:	**Supervising Committee of the Bellefield Boiler Plant** 4400 Forbes Avenue Pittsburgh, PA 15213-4080
Permittee/Operator: **(if not Owner)**	Same As Owner
Responsible Official:	**Kevin D. Hiles**
Title:	Chairman
Company:	Supervising Committee of the Bellefield Boiler Plant
Address:	4400 Forbes Avenue Pittsburgh, PA 15213-4080
Telephone Number:	412-622-3351
Fax Number:	412-622-3388
Facility Contact:	**Anthony Young**
Title:	Chairman, Operating Committee
Telephone Number:	412-578-2495
Fax Number:	412-622-3388
E-mail Address:	**youngt@carnegiemuseums.org**

AGENCY ADDRESSES:

ACHD Contact:	**Chief Engineer** **Allegheny County Health Department** Air Quality Program 301 39th Street, Building #7 Pittsburgh, PA 15201-1811
EPA Contact:	**Enforcement Programs Section (3AP12)** **USEPA Region III** 1650 Arch Street Philadelphia, PA 19103-2029

II. FACILITY DESCRIPTION

FACILITY DESCRIPTION

The Bellefield Boiler Plant is a captive steam generation facility located on South Neville Street in the Oakland section of Pittsburgh, PA and it supplies steam for heating to institutional sites in that area. The plant is composed of six (6) boilers emitting from one stack. All of the boilers fire natural gas as their primary fuel. The boilers have the capacity to fire no. 2 fuel oil with sulfur content of 0.05% (500 ppm) at times of emergency, including natural gas curtailment and natural gas supply interruption, and during maintenance, periodic testing and startups with the exception of boilers 1, 5 and 8a, which do not have the capability to fire fuel oil. Boilers 3, 6 and 7 emergency fuel oil usage will be based on an annual capacity factor of 4.91%, which is 430 hours/year. The facility also has two (2) oil fired emergency generators rated at 771 hp (5.4 MMbtu/hr) each.

The facility is a major source of nitrogen oxides (NO_X) and carbon monoxide emissions (CO), a minor source of particulate matter (PM), particulate matter < 10 microns in diameter. (PM_{10}), sulfur oxide (SO_X), volatile organic compounds (VOCs) and hazardous air pollutants (HAPs) as defined in section 2101.20 of Article XXI.

INSTALLATION DESCRIPTION

This installation permit is for inclusion of physical and operational conditions for subject facility pursuant to Reasonable Available Control Technology (RACT II) in section 2105.06 of Article XXI. There are no new units being added to the facility as part of this permitting action.

The emission units regulated by this permit are summarized in Table II-1:

TABLE II-1: Emission Unit Identification

I.D.	SOURCE DESCRIPTION	CONTROL DEVICE(S)	MAXIMUM CAPACITY	FUEL/RAW MATERIAL	STACK I.D.
B001	Boiler 1	None	74 MMBtu/Hr	Natural Gas	S002
B003	Boiler 3	None	119 (fuel oil); 128 (natural gas) MMBtu/Hr	Natural Gas/ No. 2 Fuel Oil	S002
B005	Boiler 5	None	74 MMBtu/Hr	Natural Gas	S002
B006	Boiler 6, Package Boiler	Flue Gas Recirculation	179 MMBtu/Hr	Natural Gas/ No. 2 Fuel Oil	S002
B007	Boiler 7, Package Boiler	Low NO_X Burners	188 MMBtu/Hr	Natural Gas/ No. 2 Fuel Oil	S002
B008a	Boiler 8a, Package Boiler	Low NO_X Burners with Optional Flue Gas Recirculation	87 MMBtu/Hr	Natural Gas	S002

DECLARATION OF POLICY

Pollution prevention is recognized as the preferred strategy (over pollution control) for reducing risk to air resources. Accordingly, pollution prevention measures should be integrated into air pollution control programs wherever possible, and the adoption by sources of cost-effective compliance strategies, incorporating pollution prevention, is encouraged. The Department will give expedited consideration to any permit modification request based on pollution prevention principles.

The permittee is subject to the terms and conditions set forth below. These terms and conditions constitute provisions of *Allegheny County Health Department Rules and Regulations, Article XXI Air Pollution Control*. The subject equipment has been conditionally approved for operation. The equipment shall be operated in conformity with the plans, specifications, conditions, and instructions which are part of your application, and may be periodically inspected for compliance by the Department. In the event that the terms and conditions of this permit or the applicable provisions of Article XXI conflict with the application for this permit, these terms and conditions and the applicable provisions of Article XXI shall prevail. Additionally, nothing in this permit relieves the permittee from the obligation to comply with all applicable Federal, State and Local laws and regulations.

III. GENERAL CONDITIONS

1. Prohibition of Air Pollution (§2101.11)

It shall be a violation of this permit to fail to comply with, or to cause or assist in the violation of, any requirement of this permit, or any order or permit issued pursuant to authority granted by Article XXI. The permittee shall not willfully, negligently, or through the failure to provide and operate necessary control equipment or to take necessary precautions, operate any source of air contaminants in such manner that emissions from such source:

a. Exceed the amounts permitted by this permit or by any order or permit issued pursuant to Article XXI;
b. Cause an exceedance of the ambient air quality standards established by Article XXI §2101.10; or
c. May reasonably be anticipated to endanger the public health, safety, or welfare.

2. Nuisances (§2101.13)

Any violation of any requirement of this Permit shall constitute a nuisance.

3. Definitions (§2101.20)

a. Except as specifically provided in this permit, terms used retain the meaning accorded them under the applicable provisions and requirements of Article XXI or the applicable federal or state regulation. Whenever used in this permit, or in any action taken pursuant to this permit, the words and phrases shall have the meanings stated, unless the context clearly indicates otherwise.

b. Unless specified otherwise in this permit or in the applicable regulation, the term "*year*" shall mean any twelve (12) consecutive months.

4. **Certification (§2102.01)**

Any report or compliance certification submitted under this permit shall contain written certification by a responsible official as to truth, accuracy, and completeness. This certification and any other certification required under this permit shall be signed by a responsible official of the source, and shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

5. **Operation and Maintenance (§2105.03)**

All air pollution control equipment required by this permit or Article XXI, and all equivalent compliance techniques that have been approved by the Department, shall be properly installed, maintained, and operated consistent with good air pollution control practice.

6. **Conditions (§2102.03.c)**

It shall be a violation of this permit giving rise to the remedies provided by Article XXI §2109.02, for any person to fail to comply with any terms or conditions set forth in this permit.

7. **Transfers (§2102.03.e)**

This permit shall not be transferable from one person to another, except in accordance with Article XXI §2102.03.e and in cases of change-in-ownership which are documented to the satisfaction of the Department, and shall be valid only for the specific sources and equipment for which this permit was issued. The transfer of permits in the case of change-in-ownership may be made consistent with the administrative permit amendment procedure of Article XXI §2103.14.b.

8. **Effect (§2102.03.g)**

Issuance of this permit shall not in any manner relieve any person of the duty to fully comply with the requirements of Article XXI or any other provision of law, nor shall it in any manner preclude or affect the right of the Department to initiate any enforcement action whatsoever for violations of Article XXI or this Permit, whether occurring before or after the issuance of such permit. Further, the issuance of this permit shall not be a defense to any nuisance action, nor shall such permit be construed as a certificate of compliance with the requirements of Article XXI or this Permit.

9. **General Requirements (§2102.04.a)**

It shall be a violation of this Permit giving rise to the remedies set forth in Article XXI §2109 for any person to install, modify, replace, reconstruct, or reactivate any source or air pollution control equipment to which this Permit applies unless either:

a. The Department has first issued an Installation Permit for such source or equipment; or

b. Such action is solely a reactivation of a source with a current Operating Permit, which is approved under §2103.13 of Article XXI.

10. **Conditions (§2102.04.e)**

Further, the initiation of installation, modification, replacement, reconstruction, or reactivation under this

Installation Permit and any reactivation plan shall be deemed acceptance by the source of all terms and conditions specified by the Department in this permit and plan.

11. Revocation (§2102.04.f)

c. The Department may, at any time, revoke this Installation Permit if it finds that:
   1) Any statement made in the permit application is not true, or that material information has not been disclosed in the application;
   2) The source is not being installed, modified, replaced, reconstructed, or reactivated in the manner indicated by this permit or applicable reactivation plan;
   3) Air contaminants will not be controlled to the degree indicated by this permit;
   4) Any term or condition of this permit has not been complied with;
   5) The Department has been denied lawful access to the premises or records, charts, instruments and the like as authorized by this Permit; or

d. Prior to the date on which construction of the proposed source has commenced the Department may, revoke this Installation Permit if a significantly better air pollution control technology has become available for such source, a more stringent regulation applicable to such source has been adopted, or any other change has occurred which requires a more stringent degree of control of air contaminants.

12. Term (§2102.04.g)

This Installation Permit shall expire in 18 months if construction has not commenced within such period or shall expire 18 months after such construction has been suspended, if construction is not resumed within such period. In any event, this Installation Permit shall expire upon completion of construction, except that this Installation Permit shall authorize temporary operation to facilitate shakedown of sources and air cleaning devices, to permit operations pending issuance of a related subsequent Operating Permit, or to permit the evaluation of the air contamination aspects of the source. Such temporary operation period shall be valid for a limited time, not to exceed 180 days, but may be extended for additional limited periods, each not to exceed 120 days, except that no temporary operation shall be authorized or extended which may circumvent the requirements of this Permit.

13. Annual Installation Permit Administrative Fee (§2102.10.c & e)

No later than 30 days after the date of issuance of this Installation Permit and on or before the last day of the month in which this permit was issued in each year thereafter, during the term of this permit until a subsequent corresponding Operating Permit or amended Operating Permit is properly applied for, the owner or operator of such source shall pay to the Department, in addition to all other applicable emission and administration fees, an Annual Installation Permit Administration Fee in an amount of $750.

14. Severability Requirement (§2103.12.l)

The provisions of this permit are severable, and if any provision of this permit is determined to by a court of competent jurisdiction to be invalid or unenforceable, such a determination will not affect the remaining provisions of this permit.

15. Reporting Requirements (§2103.12.k)

a. The permittee shall submit reports of any required monitoring at least every six (6) months. All instances of deviations from permit requirements must be clearly identified in such reports. All required reports must be certified by the Responsible Official.

b. Prompt reporting of deviations from permit requirements is required, including those attributable to upset conditions as defined in this permit and Article XXI §2108.01.c, the probable cause of such deviations, and any corrective actions or preventive measures taken.

c. All reports submitted to the Department shall comply with the certification requirements of General Condition III.4 above.

d. Semiannual reports required by this permit shall be submitted to the Department as follows:

1) One semiannual report is due by April 30 of each year for the time period beginning October 1 of the previous year through March 31 of that same year.
2) One semiannual report is due by October 31 of each year for the time period beginning April 1 and ending September 30 of that same year.
3) The next semiannual report shall be due April 30, 2020 for the time period beginning on the issuance date of this permit through March 31, 2020.

e. Reports may be emailed to the Department at aqreports@alleghenycounty.us in lieu of mailing a hard copy.

16. Minor Installation Permit Modifications (§2102.10.d)

Modifications to this Installation Permit may be applied for but only upon submission of an application with a fee in the amount of $300 and where:

a. No reassessment of any control technology determination is required; and
b. No reassessment of any ambient air quality impact is required.

17. Violations (§2104.06)

The violation of any emission standard established by this Permit shall be a violation of this Permit giving rise to the remedies provided by Article §2109.02.

18. Other Requirements Not Affected (§2105.02)

Compliance with the requirements of this permit shall not in any manner relieve any person from the duty to fully comply with any other applicable federal, state, or county statute, rule, regulation, or the like, including, but not limited to, any applicable NSPSs, NESHAPs, MACTs, or Generally Achievable Control Technology standards now or hereafter established by the EPA, and any applicable requirement of BACT or LAER as provided by Article XXI, any condition contained in this Installation Permit and/or any additional or more stringent requirements contained in an order issued to such person pursuant to Part I of Article XXI.

19. Other Rights and Remedies Preserved (§2109.02.b)

Nothing in this permit shall be construed as impairing any right or remedy now existing or hereafter created in equity, common law or statutory law with respect to air pollution, nor shall any court be deprived of such jurisdiction for the reason that such air pollution constitutes a violation of this permit

20. Penalties, Fines, and Interest (§2109.07.a)

A source that fails to pay any fee required under this Permit or article XXI when due shall pay a civil penalty of 50% of the fee amount, plus interest on the fee amount computed in accordance with of Article XXI §2109.06.a.4 from the date the fee was required to be paid. In addition, the source may have its permit revoked.

21. Appeals (§2109.10)

In accordance with State Law and County regulations and ordinances, any person aggrieved by an order or other final action of the Department issued pursuant to Article XXI shall have the right to appeal the action to the Director in accordance with the applicable County regulations and ordinances.

IV. SITE LEVEL TERMS AND CONDITIONS

1. Reporting of Upset Conditions (§2103.12.k.2)

The permittee shall promptly report all deviations from permit requirements, including those attributable to upset conditions as defined in Article XXI §2108.01.c, the probable cause of such deviations, and any corrective actions or preventive measures taken.

2. Visible Emissions (§2104.01.a)

Except as provided for by Article XXI §2108.01.d pertaining to a cold start, no person shall operate, or allow to be operated, any source in such manner that the opacity of visible emissions from a flue or process fugitive emissions from such source, excluding uncombined water:

a. Equal or exceed an opacity of 20% for a period or periods aggregating more than three (3) minutes in any sixty (60) minute period; or,
b. Equal or exceed an opacity of 60% at any time.

3. Odor Emissions (§2104.04) (County-only enforceable)

No person shall operate, or allow to be operated, any source in such manner that emissions of malodorous matter from such source are perceptible beyond the property line.

4. Materials Handling (§2104.05)

The permittee shall not conduct, or allow to be conducted, any materials handling operation in such manner that emissions from such operation are visible at or beyond the property line.

5. Operation and Maintenance (§2105.03)

All air pollution control equipment required by this permit or any order under Article XXI, and all equivalent compliance techniques approved by the Department, shall be properly installed, maintained, and operated consistently with good air pollution control practice.

6. Open Burning (§2105.50)

No person shall conduct, or allow to be conducted, the open burning of any material, except where the Department has issued an Open Burning Permit to such person in accordance with Article XXI §2105.50 or where the open burning is conducted solely for the purpose of non-commercial preparation of food for human consumption, recreation, light, ornament, or provision of warmth for outside workers, and in a manner which contributes a negligible amount of air contaminants.

7. Shutdown of Control Equipment (§2108.01.b)

a. In the event any air pollution control equipment is shut down for reasons other than a breakdown, the person responsible for such equipment shall report, in writing, to the Department the intent to shut down such equipment at least 24 hours prior to the planned shutdown. Notwithstanding the submission of such report, the equipment shall not be shut down until the approval of the Department is obtained; provided, however, that no such report shall be required if the source(s) served by such air pollution control equipment is also shut down at all times that such equipment is shut down.

b. The Department shall act on all requested shutdowns as promptly as possible. If the Department does not take action on such requests within ten (10) calendar days of receipt of the notice, the request shall be deemed denied, and upon request, the owner or operator of the affected source shall have a right to appeal in accordance with the provisions of Article XI.

c. The prior report required by Site Level Condition IV.7.a above shall include:

1) Identification of the specific equipment to be shut down, its location and permit number (if permitted), together with an identification of the source(s) affected;
2) The reasons for the shutdown;
3) The expected length of time that the equipment will be out of service;
4) Identification of the nature and quantity of emissions likely to occur during the shutdown;
5) Measures, including extra labor and equipment, which will be taken to minimize the length of the shutdown, the amount of air contaminants emitted, or the ambient effects of the emissions;
6) Measures which will be taken to shut down or curtail the affected source(s) or the reasons why it is impossible or impracticable to shut down or curtail the affected source(s) during the shutdown; and
7) Such other information as may be required by the Department.

8. Breakdowns (§2108.01.c)

a. In the event that any air pollution control equipment, process equipment, or other source of air contaminants breaks down in such manner as to have a substantial likelihood of causing the emission of air contaminants in violation of this permit, or of causing the emission into the open air of potentially toxic or hazardous materials, the person responsible for such equipment or source shall immediately, but in no event later than sixty (60) minutes after the commencement of the breakdown, notify the Department of such breakdown and shall, as expeditiously as possible but in no event later than seven (7) days after the original notification, provide written notice to the Department.

b. To the maximum extent possible, all oral and written notices required shall include all pertinent facts, including:

1) Identification of the specific equipment which has broken down, its location and permit number (if permitted), together with an identification of all related devices, equipment, and other sources which will be affected.
2) The nature and probable cause of the breakdown.
3) The expected length of time that the equipment will be inoperable or that the emissions will continue.
4) Identification of the specific material(s) which are being, or are likely to be emitted, together with a statement concerning its toxic qualities, including its qualities as an irritant, and its potential for causing illness, disability, or mortality.
5) The estimated quantity of each material being or likely to be emitted.
6) Measures, including extra labor and equipment, taken or to be taken to minimize the length of the breakdown, the amount of air contaminants emitted, or the ambient effects of the emissions, together with an implementation schedule.
7) Measures being taken to shut down or curtail the affected source(s) or the reasons why it is impossible or impractical to shut down the source(s), or any part thereof, during the breakdown.

c. Notices required shall be updated, in writing, as needed to advise the Department of changes in the information contained therein. In addition, any changes concerning potentially toxic or hazardous emissions shall be reported immediately. All additional information requested by the Department shall be submitted as expeditiously as practicable.

d. Unless otherwise directed by the Department, the Department shall be notified whenever the condition causing the breakdown is corrected or the equipment or other source is placed back in operation by no later than 9:00 AM on the next County business day. Within seven (7) days thereafter, written notice shall be submitted pursuant to Paragraphs a and b above.

e. Breakdown reporting shall not apply to breakdowns of air pollution control equipment which occur during the initial startup of said equipment, provided that emissions resulting from the breakdown are of the same nature and quantity as the emissions occurring prior to startup of the air pollution control equipment.

f. In no case shall the reporting of a breakdown prevent prosecution for any violation of this permit or Article XXI.

9. Cold Start (§2108.01.d)

In the event of a cold start on any fuel-burning or combustion equipment, except stationary internal combustion engines and combustion turbines used by utilities to meet peak load demands, the person responsible for such equipment shall report in writing to the Department the intent to perform such cold start at least 24 hours prior to the planned cold start. Such report shall identify the equipment and fuel(s) involved and shall include the expected time and duration of the startup. Upon written application from the person responsible for fuel-burning or combustion equipment which is routinely used to meet peak load demands and which is shown by experience not to be excessively emissive during a cold start, the Department may waive these requirements and may instead require periodic reports listing all cold starts which occurred during the report period. The Department shall make such waiver in writing, specifying such terms and conditions as are appropriate to achieve the purposes of Article XXI. Such waiver may be terminated by the Department at any time by written notice to the applicant.

10. Monitoring of Malodorous Matter Beyond Facility Boundaries (§2104.04)

The permittee shall take all reasonable action as may be necessary to prevent malodorous matter from becoming perceptible beyond facility boundaries. Further, the permittee shall perform such observations as may be deemed necessary along facility boundaries to ensure that malodorous matter beyond the facility boundary in accordance with Article XXI §2107.13 is not perceptible and record all findings and corrective action measures taken.

11. Emissions Inventory Statements (§2108.01.e & g)

a. Emissions inventory statements in accordance with §2108.01.e shall be submitted to the Department by March 15 of each year for the preceding calendar year. The Department may require more frequent submittals if the Department determines that more frequent submissions are required by the EPA or that analysis of the data on a more frequent basis is necessary to implement the requirements of Article XXI or the Clean Air Act.

b. The failure to submit any report or update within the time specified, the knowing submission of false information, or the willful failure to submit a complete report shall be a violation of this permit giving rise to the remedies provided by Article XXI §2109.02.

12. Orders (§2108.01.f)

In addition to meeting the requirements Site Level Conditions IV.7 through IV.11, inclusive, the person responsible for any source shall, upon order by the Department, report to the Department such information as the Department may require in order to assess the actual and potential contribution of the source to air quality. The order shall specify a reasonable time in which to make such a report.

13. Violations (§2108.01.g)

The failure to submit any report or update thereof required by Site Level Conditions IV.7 through IV.12 above, inclusive, within the time specified, the knowing submission of false information, or the willful failure to submit a complete report shall be a violation of this permit giving rise to the remedies provided by Article XXI §2109.02.

14. Emissions Testing (§2108.02)

a. **Orders:** No later than 60 days after achieving full production or 120 days after startup, whichever is earlier, the permittee shall conduct, or cause to be conducted, such emissions tests as are specified by the Department to demonstrate compliance with the applicable requirements of this permit and shall submit the results of such tests to the Department in writing. Upon written application setting forth all information necessary to evaluate the application, the Department may, for good cause shown, extend the time for conducting such tests beyond 120 days after startup but shall not extend the time beyond 60 days after achieving full production. Emissions testing shall comply with all applicable requirements of Article XXI, §2108.02.e.

b. **Tests by the Department:** Notwithstanding any tests conducted pursuant to this permit, the Department or another entity designated by the Department may conduct emissions testing on any source or air pollution control equipment. At the request of the Department, the permittee shall provide adequate sampling ports, safe sampling platforms and adequate utilities for the performance of such tests.

c. **Testing Requirements:** No later than 45 days prior to conducting any tests required by this permit, the person responsible for the affected source shall submit for the Department's approval a written test protocol explaining the intended testing plan, including any deviations from standard testing procedures, the proposed operating conditions of the source during the test, calibration data for specific test equipment and a demonstration that the tests will be conducted under the direct supervision of persons qualified by training and experience satisfactory to the Department to conduct such tests. In addition, at least 30 days prior to conducting such tests, the person responsible shall notify the Department in writing of the time(s) and date(s) on which the tests will be conducted and shall allow Department personnel to observe such tests, record data, provide pre-weighed filters, analyze samples in a County laboratory and to take samples for independent analysis. Test results shall be comprehensively and accurately reported in the units of measurement specified by the applicable emission limitations of this permit.

d. Test methods and procedures shall conform to the applicable reference method set forth in this permit or Article XXI Part G, or where those methods are not applicable, to an alternative sampling and testing procedure approved by the Department consistent with Article XXI §2108.02.e.2.

e. **Violations:** The failure to perform tests as required by this permit or an order of the Department, the failure to submit test results within the time specified, the knowing submission of false information, the willful failure to submit complete results, or the refusal to allow the Department, upon presentation of a search warrant, to conduct tests, shall be a violation of this permit giving rise to the remedies provided by Article XXI §2109.02.

15. Abrasive Blasting (§2105.51)

a. Except where such blasting is a part of a process requiring an operating permit, no person shall conduct or allow to be conducted, abrasive blasting or power tool cleaning of any surface, structure, or part thereof, which has a total area greater than 1,000 square feet unless such abrasive blasting complies with all applicable requirements of Article XXI §2105.51.

b. In addition to complying with all applicable provisions of §2105.51, no person shall conduct, or allow to be conducted, abrasive blasting of any surface unless such abrasive blasting also complies with all other applicable requirements of Article XXI unless such requirements are specifically addressed by §2105.51.

16. Asbestos Abatement (§2105.62, §2105.63)

In the event of removal, encasement, or encapsulation of Asbestos-Containing Material (ACM) at a facility or in the event of the demolition of any facility, the permittee shall comply with all applicable provisions of Article XXI §2105.62 and §2105.63.

17. Volatile Organic Compound Storage Tanks (§2105.12.a)

No person shall place or store, or allow to be placed or stored, a volatile organic compound having a vapor pressure of 1.5 psia or greater under actual storage conditions in any aboveground stationary storage tank having a capacity equal to or greater than 2,000 gallons but less than or equal to 40,000 gallons, unless there is in operation on such tank pressure relief valves which are set to release at the higher of 0.7 psig of pressure or 0.3 psig of vacuum or at the highest possible pressure and vacuum in accordance with State or local fire codes, National Fire Prevention Association guidelines, or other national consensus standard approved in writing by the Department. Petroleum liquid storage vessels that are used to store produced crude oil and condensate prior to lease custody transfer are exempt from these requirements.

18. Fugitive Emissions (§2105.49)

The person responsible for a source of fugitive emissions, in addition to complying with all other applicable provisions of this permit shall take all reasonable actions to prevent fugitive air contaminants from becoming airborne. Such actions may include, but are not limited to:

a. The use of asphalt, oil, water, or suitable chemicals for dust control;
b. The paving and maintenance of roadways, parking lots and the like;
c. The prompt removal of earth or other material which has been deposited by leaks from transport, erosion or other means;
d. The adoption of work or other practices to minimize emissions;
e. Enclosure of the source; and
f. The proper hooding, venting, and collection of fugitive emissions.

19. Episode Plans (§2106.02)

The permittee shall upon written request of the Department, submit a source curtailment plan, consistent with good industrial practice and safe operating procedures, designed to reduce emissions of air contaminants during air pollution episodes. Such plans shall meet the requirements of Article XXI §2106.02.

20. New Source Performance Standards (§2105.05)

a. It shall be a violation of this permit giving rise to the remedies provided by §2109.02 of Article XXI for any person to operate, or allow to be operated, any source in a manner that does not comply with all requirements of any applicable NSPS now or hereafter established by the EPA, except if such person has obtained from EPA a waiver pursuant to Section 111 or Section 129 of the Clean Air Act or is otherwise lawfully temporarily relieved of the duty to comply with such requirements.

b. Any person who operates, or allows to be operated, any source subject to any NSPS shall conduct, or cause to be conducted, such tests, measurements, monitoring and the like as is required by such standard. All notices, reports, test results and the like as are required by such standard shall be submitted to the Department in the manner and time specified by such standard. All information, data and the like which is required to be maintained by such standard shall be made available to the Department upon request for inspection and copying.

V. EMISSION UNIT LEVEL TERMS AND CONDITIONS

A. NO_x Limits: Natural Gas Only Boilers 1, 5 & 8a

1. Restrictions:

a. The permittee shall continue to meet the conditions of the current Title V Operating Permit #0047not otherwise affected by the revisions in this permit. [§2102.04.b.5; §2105.06.d]

b. Natural gas combustion from each boiler 1 and 5 shall not exceed the maximum potential usage of 70,476 scf in any one-hour period and 617.37 mmscf in any consecutive twelve-month period, based on a natural gas heat content of 1,050 Btu/scf. [§2103.12.h.1]

c. NO_X emissions from the following sources shall not exceed the limitations in Table V-A-1 below: [25 pa code §129.97(g)(1); §2102.04.b.5; §2105.06.d]

TABLE V-A-1: NO_X Emission Limitations

Process	Maximum Heat Input Capacity MMBtu/hr	Emission Limit** lbs/MMBtu	Hourly Emission Limit (lb/hr)	Annual Emission Limit (tons/year)*
Boiler 1	74	0.10	7.4	32.4
Boiler 5	74	0.10	7.4	32.4

*A year is defined as any consecutive 12-month period.
**Based on the PADEP presumptive RACT limit in 25 PA. Code, Chapter 129.97(g)(1)(i)).

d. NO_X emissions from boiler 8a shall not exceed the limitations in Table V-A-2 below: [25 pa code §129.97(g)(1); §2102.04.b.5; §2105.06.d]

TABLE V-A-2: NO_X Emission Limitations

Process	Maximum Heat Input Capacity MMBtu/hr	Emission Limit** lbs/MMBtu	Hourly Emission Limit (lb/hr)	Annual Emission Limit (tons/year)*
Boiler 8a	87	0.055	4.79	20.98

*A year is defined as any consecutive 12-month period.

2. Testing Requirements:

a. The permittee shall perform nitrogen oxides emissions testing while combusting natural gas on boilers no. 1 & 5 once every five years to demonstrate compliance with the emission limitations in condition V.A.1.c. Such testing shall be conducted in accordance with applicable U.S. EPA test methods 7 through 7E or other test methods approved by the Department, §2108.02 and Site Level Condition IV.14. [§2103.12.h.1; §2108.02; §2105.06.d]

b. The Department reserves the right to require additional emissions testing sufficient to assure compliance with the terms and conditions of this permit. Such testing shall be performed in accordance with Article XXI §2108.02. [§2103.12.h.1]

3. **Monitoring Requirements**

a. The permittee shall monitor and inspect the boilers weekly to insure the physical integrity of the boilers and associated equipment and to make sure the boilers are being operated and maintained properly. Steam load and natural gas usage shall be monitored and recorded to fulfill the recording requirements of V.A.4.a below. [§2105.06; §2103.12.i]

b. The permittee shall provide Department approved instrumentation to monitor the oxygen content, CO and NO_X of the boilers exhaust on a monthly basis during operation. The oxygen content of the flue gas shall be monitored to within 3% of the measured value and be recorded to the nearest 0.1%, to ensure that the subject boilers are being operated and maintained properly. The instrumentation shall be maintained in good working condition at all times and be easily accessible. [§2103.12.i; §2105.06]

4. **Record Keeping Requirements:**

a. The permittee shall keep and maintain the following data for the boilers: [§2105.06; §2103.12.j; §2103.12.h.1]:

1) Type and amount of fuel combusted (MMscf of natural gas/day and monthly total natural gas combusted);
2) Steam load (lbs/hr, lbs/day; average daily steam load for each month);
3) Cold starts (date, time and duration of each occurrence);
4) Total operating hours, (hours/day, monthly and 12-month); and
5) Records of operation, maintenance, inspection, calibration and/or replacement of combustion equipment (e.g. burner replacement, flame pattern adjustments, and air-to-fuel ratios).

b. The permittee shall record all instances of non-compliance with the conditions of this permit upon occurrence along with corrective action taken to restore compliance. [§2105.06; §2103.12.j; §2103.12.h.1]

c. All records required under this section shall be maintained by the permittee for a period of five years following the date of such record. These records shall be made available to the Department upon request for inspection and/or copying. [§2105.06; §2103.12.j.2; §2103.12.h.1]

5. **Reporting Requirements:**

a. The permittee shall submit semi-annual reports to the Department in accordance with General Condition III.15. The reports shall contain all required information for the time period of the report: [§2105.06; §2103.12.k.1]

1) Type and amount of fuel combusted (Monthly and 12-month);
2) Steam load (average daily steam load for each month);
3) Cold starts (date, time and duration of each occurrence);
4) Total operating hours.

b. The permittee shall report instances of non-compliance as required to be recorded by V.A.4.b. [§2103.12.k]

c. Reporting instances of non-compliance does not relieve the permittee of the requirement to report breakdowns in accordance with Site Level Condition IV.8, if appropriate. [§2103.12.k]

6. Work Practice Standard:

None except as provided elsewhere.

7. Additional Requirements:

None except as provided elsewhere.

B. NO_X Limits: Natural Gas Boiler 3, 6 & 7 & No.2 Fuel Oil for Emergencies.

1. Restrictions:

a. The permittee shall continue to meet the conditions of the current Title V Operating Permit #0047not otherwise affected by the revisions in this RACT permit. [§2102.04.b.5; §2105.06.d]

b. Boiler no. 3 annual capacity factor shall not exceed 50% during any consecutive twelve-month period. [§2105.06.d]

c. Boiler no. 7 annual capacity factor shall not exceed 39% during any consecutive twelve-month period when firing natural gas. [§2105.06.d]

d. Boiler no.7 shall be equipped with low NO_X burners that meet the emission limitation in condition V.B.1.f below. [§2105.06.d]

e. The permittee shall not operate boiler No. 7 unless a NO_X Continuous Emission Monitoring (CEM) system is present at all times and properly operated and maintained according to 40 CFR 60, Subpart Db [§2105.06.d; §2103.12.a.2.B; 25 PA Code §123.51]

f. NOx Emissions from the following sources when firing Natural Gas shall not exceed the limitations in Table V-B-1 below: [25 pa code §129.97(g)(1); 25 pa code §129.97(c); 25 pa code §129.99; §2102.04.b.5; §2105.06.d; §2103.12.h.1]

TABLE V-B-1: NO_X Emission Limitations Firing Natural Gas

Process	Maximum Heat Input Capacity MMBtu/hr	Natural Gas*** Usage	Emission Limit lbs/MMBtu	Hourly Emission Limit (lb/hr)	Annual Emission Limit (tons/year)*
Boiler 3***	128	121,905 Scf/hr 533.94 MMcf/yr	0.20	25.60	56.06
Boiler 6**	179	170,476 Scf/hr 1,494 MMscf/yr	0.10	17.90	78.40
Boiler 7***	188	179,048 Scf/hr 609 MMscf/yr	0.14	26.32	44.74

*A year is defined as any consecutive 12-month period.
**Based on the PADEP presumptive RACT limit in 25 PA. Code, Chapter 129.97(g)(1)(i)).
***Based on case-by-case and 2012 stack test and 2014 CEM test for boiler 7
****Based on NG heating content 1050 Btu/scf

g. The permittee shall not operate or allow to be operated boiler no. 3, 6 & 7 for more than 430 hours during any consecutive twelve-month period when firing No. 2 fuel oil. [25 PA Code §129.96(c); §2105.06.d]

h. All fuel oil combusted shall meet current ASTM specifications for no. 2 fuel oil and have a maximum sulfur content of 0.05% by weight at all times [§2105.06.d]

i. Boiler no. 3, 6 & 7 annual capacity factor shall not exceed 4.91% during any consecutive twelve-month period when firing No. 2 fuel oil. [25 PA Code §129.96(c)(7); §2105.06.d]

j. NO_X Emissions from the following sources when firing No. 2 fuel oil for emergencies shall not exceed the limitations in Table V-B-2 below: [25 pa code §129.97(c); §2102.04.b.5; §2105.06.d; §2103.12.h.1]

TABLE V-B-2: NO_X Emission Limitations Firing Fuel Oil

Process	Maximum Heat Input Capacity MMBtu/hr	No. 2 Fuel Oil Usage	Emission Limit lbs/MMBtu	Hourly Emission Limit (lb/hr)	Annual Emission Limit (tons/year)*
Boiler 3	119	850 gal/hr 365,500 gal/yr	0.63	74.97	16.12
Boiler 6**	179	1,280 gal/hr 550,400 gal/yr	0.28	50.12	10.78
Boiler 7	188	1,340 gal/hr 567,200 gal/yr	0.20	37.60	8.08

*A year is defined as any consecutive 12-month period.

2. **Testing Requirements:**

a. The permittee shall perform nitrogen oxides emissions testing while combusting natural gas on boiler no. 3 & 6 once every five years to demonstrate compliance with the emission limitations in condition V.B.1.f. Such testing shall be conducted in accordance with applicable U.S. EPA test methods 7 through 7E or other test methods approved by the Department, Article XXI §2108.02 and Site Level Condition IV.14. [§2103.12.h.1; §2108.02; §2105.06.d]

b. The permittee shall perform Relative Accuracy Test Audits (RATA) of the boiler no. 7 NO_X CEMS as specified in 25 PA Code §§139.101 - 139.111 to determine compliance with the boiler 7 emission limitations in condition V.B.1.f. [§2108.03; §2105.06.d]

c. The Department reserves the right to require additional emissions testing sufficient to assure compliance with the terms and conditions of this permit. Such testing shall be performed in accordance with Article XXI §2108.02. [§2103.12.h.1]

3. **Monitoring Requirements**

a. The permittee shall monitor and inspect the boilers weekly to insure the physical integrity of the boilers and associated equipment and to make sure the boilers are being operated and maintained properly. Steam load and natural gas usage shall be monitored and recorded to fulfill the recording requirements of V.B.4.a below. [§2105.06; §2103.12.i]

b. The permittee shall provide Department approved instrumentation to monitor the oxygen content, CO and NO_X of the boilers exhaust on a monthly basis during operation. The oxygen content of the flue gas shall be monitored to within 3% of the measured value and be recorded to the nearest 0.1%, to ensure that the subject boilers are being operated and maintained properly. The instrumentation shall be maintained in good working condition at all times and be easily accessible. [§2103.12.i; §2105.06]

4. **Record Keeping Requirements:**

a. The permittee shall keep and maintain the following data for the boilers: [§2105.06; §2103.12.j; §2103.12.h.1];
   1) Type and amount of fuel combusted (MMscf of natural gas/day and monthly total natural gas combusted);
   2) Steam load (lbs/hr, lbs/day; average daily steam load for each month);
   3) Cold starts (date, time and duration of each occurrence);
   4) Total operating hours, (hours/day, monthly and 12-month);
   5) Records of operation, maintenance, inspection, calibration and/or replacement of combustion equipment (e.g. burner replacement, flame pattern adjustments, and air-to-fuel ratios); and

b. The permittee shall record all instances of non-compliance with the conditions of this permit upon occurrence along with corrective action taken to restore compliance. [§2105.06; §2103.12.j; §2103.12.h.1]

c. All records required under this section shall be maintained by the permittee for a period of five years following the date of such record. These records shall be made available to the Department upon request for inspection and/or copying. [§2105.06; §2103.12.j.2; §2103.12.h.1]

5. Reporting Requirements:

a. The permittee shall submit semi-annual reports to the Department in accordance with General Condition III.15. The reports shall contain all required information for the time period of the report: [§2105.06; §2103.12.k.1]

   1) Type and amount of fuel combusted (Monthly and 12-month);
   2) Steam load (average daily steam load for each month);
   3) Cold starts (date, time and duration of each occurrence);
   4) Total operating hours.

b. Report instances of non-compliance as required to be recorded by V.B.4.b. [§2103.12.k]

c. Reporting instances of non-compliance does not relieve the permittee of the requirement to report breakdowns in accordance with Site Level Condition IV.8, if appropriate. [§2103.12.k]

6. Work Practice Standard:

None except as provided elsewhere.

7. Additional Requirements:

None except as provided elsewhere.

C. Emergency Generators

Process Description: Two (2) Emergency Generators A & B
Facility ID: EG 1 & EG 2
Max. Design Rate: 771 hp (5.4 MMBtu/hr) each
Fuel: Diesel
Control Device: None

1. Restrictions:

a. The permittee shall install, maintain and operate the emergency generators in accordance with the manufacturer's specifications and with good operating practices. [§2105.03; 25 PA Code §129.97 (c)]

b. The generators shall combust only diesel fuel. All diesel fuel combusted shall have a maximum allowable sulfur content of 0.05%, by weight. [§2103.12.h]

VI. ALTERNATIVE OPERATING SCENARIOS

None except as provided elsewhere

VII. EMISSIONS LIMITATIONS SUMMARY

The following table summarizes the annual maximum potential RACT II NO_X emissions for Boilers 1 through 8a.

TABLE VII-1: Emission Limitations Summary

Pollutant	Annual Combined** Emission Limit (tons/year)*
Nitrogen Oxides (NO_X)	299.97

*A year is defined as any consecutive 12-month period.

** Combined emission limits for Boilers 3, 6 and 7 based on worst case scenario operation of boiler on natural gas and/or fuel oil.

ALLEGHENY COUNTY HEALTH DEPARTMENT
AIR QUALITY PROGRAM

December 11, 2019

SUBJECT: **Reasonable Available Control Technology (RACT II) Determination**
Bellefield Boiler Plant
4400 Forbes Avenue, Pittsburgh
Pittsburgh, PA 15213-4080
Allegheny County

Installation Permit No. 0047-I003

TO: JoAnn Truchan, P.E.
Section Chief, Engineering

FROM: Hafeez Ajenifuja
Air Quality Engineer

I. Executive Summary

Bellefield Boiler Plant is defined as a major source of NO_X emissions and was subjected to a Reasonable Available Control Technology II (RACT II) review by the Allegheny County Health Department (ACHD) required for the 1997 and 2008 Ozone National Ambient Air Quality Standard (NAAQS). The findings of the review established that technically and financially feasible RACT would result in the following emissions changes, summarized below.

Table 1 **Technically and Financially Feasible Control Options Summary for NO_X**

Unit ID	Emissions Unit	Financially Feasible Control Option	Current NO_X PTE	RACT Reduction	Revised NO_X PTE	Annualized Control Cost ($/yr)	Cost Effectiveness ($/ton NO_X removed)
B001	Boiler 1	Presumptive	298.19	265.79	32.40	$0	$0
B003	Boiler 3	case-by-case	167.80	111.74	56.06	$226,000	$8,100
B005	Boiler 5	Presumptive	195.23	162.83	32.40	$0	$0
B006	Boiler 6, Package Boiler	Presumptive	207.00	128.60	78.40	$0	$0
B007	Boiler 7, Package Boiler	case-by-case	38.0	-6.74	44.74	$489,000	$18,300
B008a	Boiler 8a, Package Boiler	No change	20.90	0	20.90	$0	$0
Total			**927.12**	**662.22**	**264.90**	**$935,000**	**$26,400**

These findings are based on the following documents:

- RACT analysis performed by ERG (0047-2015-02-17ract.pdf)
- RACT analysis performed by Bellefield Boiler Plant (0047r2015-01-30.pdf)
- BACT analysis performed by Bellefield Boiler Plant (see Application for Permit No. 0047-I003 dated 6/30/2017

II. Regulatory Basis

ACHD requested all major sources of NO_X (potential emissions of 100 tons per year or greater) and all major sources of VOC (potential emissions of 50 tons per year or greater) to reevaluate NO_X and/or VOC RACT for incorporation into Allegheny County's portion of the PA SIP. This document is the result of ACHD's determination of RACT for Bellefield Boiler Plant based on the materials submitted by the subject source and other relevant information.

III. Facility Description

Bellefield Boiler Plant is a captive steam generation facility located on S. Neville Street in the Oakland section of Pittsburgh, PA and it supplies steam for heating to institutional sites in that area. The plant is composed of six (6) boilers emitting from one stack. All the boilers fire natural gas as their primary fuel.

The boilers have the capacity to fire no. 2 fuel oil with sulfur content of 0.05% (500 ppm) at times of emergency, including natural gas curtailment and natural gas supply interruption, and during maintenance, periodic testing and startups except for boilers 1, 5 and 8a, which do not have the capability to fire fuel oil. Boilers 3, 6 and 7 emergency fuel oil usage will be based on an annual capacity factor of 4.91%, which is 430 hours/year. The facility also has two (2) oil fired emergency generators rated at 771 hp (5.4 MMbtu/hr) each. On December 19th, 1996 the facility entered into a consent decree with the Department to meet RACT I obligations under RACT Order No. 248.

Table 2	**Facility Sources Subject to Case-by-Case RACT II and Their Existing RACT I Limits**				
Source ID	**Description**	**Rating**	**NO_X PTE (TPY)**	**NO_X Presumptive Limit (RACT II)**	**NO_X Limit (RACT I)**
B003	Boiler 3	128 MMBtu/hr	167.80	0.10 lb/MMBtu	0.63 lb/MMBtu
B007	Boiler 7	188 MMBtu/hr	38	0.10 lb/MMBtu	0.20 lb/MMBtu

Table 3	**Facility Sources Subject to the Presumptive RACT II per PA Code 129.97**				
Source ID	**Description**	**Rating**	**NO_X PTE (TPY)**	**NO_X Presumptive Limit (RACT II)**	**NO_X Limit (RACT I)**
B001	Boiler 1-Uncontrolled	74 MMBtu/hr	32.40	0.10 lb/MMBtu	0.92 lb/MMBtu
B005	Boiler 5-Uncontrolled	74 MMBtu/hr	32.40	0.10 lb/MMBtu	0.59 lb/MMBtu
B006	Boiler 6, Package Boiler- Controlled	179 MMBtu/hr	78.40	0.10 lb/MMBtu	0.28 lb/MMBtu
B008a	Boiler 8a	87 MMBtu/hr	20.98	0.10 lb/MMBtu	NA
EG 1 & 2	Two (2) Emergency Generators	771 hp (5.4MMBtuhr), each	The permittee shall install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices.		

IV. RACT Determination

Bellefield Boiler Pant conducted stack testing on Boilers B-001, B-005 and B-006 in November 2016, with the boilers burning only natural gas. The stack testing indicated that these boilers could comply with the PADEP presumptive NOx RACT limit of 0.10 lb/MMBtu. Therefore, BBP proposes that these three boilers have RACT II limits based on the presumptive RACT limit. No further analysis is required.

Boiler 8a NOx in the Title V operating permit is restricted to 0.055 lb/MMBtu limit, which is more stringent than the presumptive RACT II of 0.10lb/MMBtu. Therefore, no further analysis is warranted.

The potential Technically Feasible Control Options for Bellefield Boiler that were evaluated are detailed in Table 4 below.

Table 4 Technically Feasible NO_X Control Cost Comparisons

Control Option		B003	B007	
Combustion Optimization	tpy NO_X Removed			
	Cost			
	$/ton			
Low NOx Burners With Flue Gas Recirculation	tpy NO_X Removed	50		
	Cost	$226,000		
	$/ton	8,100		
Low Excess Air	tpy NO_X Removed			
	Cost			
	$/ton			
Staged Combustion	tpy NO_X Removed			
	Cost			
	$/ton			
Selective Catalytic Reduction + FGR	tpy NO_X Removed		93	
	Cost		489,000	
	$/ton		18,300	
Selective Non-Catalytic Reduction	tpy NO_X Removed			
	Cost			
	$/ton			
Combustion / Performance Optimization	tpy NO_X Removed			
	Cost			
	$/ton			
Abide by Manufacturer Maintenance Schedule	tpy NO_X Removed			
	Cost			
	$/ton			

The cost proposal and installation of LNB + FGR in Boiler B-003 would cost $8,100 per ton of NOx removed which is not economically infeasible. An annual tune-up is determined to be NOx RACT for Boiler B-003.

Boiler B-007 is already equipped with a low-NOx burner with the capability of meeting a NOx emission limit of 0.14 lb/MMBtu. The next technologically feasible control option is FGR + SCR and based on the costs shown in Table 5 ($18,300 tons/NOx removed) above, FGR + SCR is not a cost-effective technological option. However, the proposed NOx RACT emission limits for Boiler B-007 is 0.14 lb/MMBtu, based on Boiler 7 CEM Relative Accuracy Test Audit (RATA), dated March 2, 2013 through February 28, 2014.

V. RACT Summary

Based on the findings in this RACT analysis, the Bellefield Boiler Plant facility emissions can be summarized as follows:

Table 5 RACT II Emission Reduction Summary

NO_X Potential Emissions (tpy)		
Current PTE	**RACT Reduction**	**Revised PTE**
923.20	623.23	299.97

As shown in Table 5, the new RACT II conditions reduce 623.23 tpy of NO_X from the Bellefield Boiler Plant facility.

VI. New and Revised RACT II IP Permit Conditions

1. Permit No. 0047-I003 Condition V.A.1.c:
2. Permit No. 0047-I003 Condition V.A.1.d
3. Permit No. 0047-I003 Condition V.B.1.f
4. Permit No. 0047-I003 Condition V.B.1.g
5. Permit No. 0047-I003 Condition V.B.1.i
6. Permit No. 0047-I003 Condition V.A.1.j
7. Permit No. 0047-I003 Condition V.C.1: The permittee shall install, maintain and operate the emergency generators in accordance with the manufacturer’s specifications and with good operating practices. [25 PA Code §129.96 (c); 25 PA Code §129.99]

Allegheny County Health Department

Technical Support Document (TSD)
REASONABLY AVAILABLE CONTROL TECHNOLOGY (RACT) DETERMINATION

Source Information

Source Name:	Bellefield Boiler Plant
Source Location:	4400 Forbes Avenue, Pittsburgh, PA 15213-4080
Mailing Address:	4400 Forbes Avenue, Pittsburgh, PA 15213-4080
County:	Allegheny
NAICS Code:	22133 (Steam and Air-Conditioning Supply)
Part 70 Permit No.:	0047
Major Source:	NO_x
Permit Reviewer:	Melissa Jativa

The Allegheny County Health Department (ACHD) has performed the following Reasonably Available Control Technology (RACT) analyses for a major source of NO_x relating to a steam generation facility located in Pittsburgh, Pennsylvania.

Background

Allegheny County was designated marginal nonattainment for the 2008 8-hour ozone on April 30, 2012 (published in 77 FR 30160, May 21, 2012). In order to implement the 2008 NAAQS for ozone, EPA issued a proposed rulemaking in June 2013 to provide steps and standards for states to develop and submit certain materials, dependent on each state's attainment status. Although Allegheny County is designated marginal nonattainment, Pennsylvania is also a part of the Ozone Transport Region (OTR), which must meet more stringent requirements, including submitting a RACT SIP for EPA approval. As such, Allegheny County must reevaluate the NO_x and VOC RACT in the existing RACT SIP for the eight-hour ozone NAAQS.

ACHD requested all major sources of NO_x (potential emissions of 100 tons per year or greater) and all major sources of VOC (potential emissions of 50 tons per year or greater) to reevaluate NO_x and/or VOC RACT for incorporation into Allegheny County's portion of the PA State Implementation Plan (SIP). This document is the result of ACHD's review of the RACT re-evaluations submitted by the subject source and supplemented with additional information as needed by ACHD.

RACT Summary

Bellefield Boiler Plant is a major source of NOx. The facility has operates six (6) boilers (No.1, 3, 5, 6, 7, 8a) which produce steam. NOx RACT evaluations were conducted the following tables show the result of those evaluations:

- Table S1 shows the RACT findings and net emission reductions;
- Table S2 compares the PA proposed presumptive RACT with RACT findings; and
- Table S3 below shows conditions considered by ACHD to be RACT.

Table S1. NOx RACT Findings for Bellefield Boiler Plant.

Unit Description	RACT[(a)]	NOx PTE before RACT	NOx PTE proposed RACT[(a)]	NOx PTE after RACT
Boiler No.1 74 MMBtu/hr	LNB + FGR; Annual Tune-up	298.19 tpy	48.6 tpy	11.8 tpy[(c)]
Boiler No 3 128 MMBtu/hr	LNB + FGR Annual Tune-up	167.8 tpy	56.1 tpy	10.2 tpy
Boiler No.5 74 MMBtu/hr	LNB + FGR; Annual Tune-up	191.23 tpy	58.3 tpy	11.8 tpy[(c)]
Boiler No.6 179 MMBtu/hr	LNB Annual Tune-up	207.0 tpy	117.6 tpy	28.6 tpy
Boiler No.7 188 MMBtu/hr	Meet Proposed Presumptive RACT Limits Annual Tune-up	38.0 tpy	28.8 tpy	20.6 tpy
Boiler No.8a 87 MMBtu/hr	Annual Tune-up	21.0 tpy	21.0 tpy	21.0 tpy[(c)]
Total		**923.22 tpy**	**330.4 tpy**	**104 tpy**
Emission Reduction			-	226.4 tpy

Where PTE=potential to emit; tpy=tons per year.

(a) Detailed RACT requirements are provided in Table S3.
(b) Annual emissions limits included in the operating permit issued December 18, 2013 do not define PTE before RACT; alternately, the before RACT is based on the requested emission rates for each boiler that was included in BBP's March 14, 2014 RACT submittal. The requested baseline emissions were established to reflect the emissions while burning natural gas.
(c) The technical literature shows that tune-ups reduce fuel consumption and a decrease in emissions will also be achieved, but it is difficult to predict the overall reduction in emissions that tune-ups can achieve because the pre-tune-up status is unknown.

Table S2. Comparison of PA proposed presumptive RACT and ACHD RACT findings.

Unit Description	Fuel	PA proposed presumptive RACT (lb/MMBtu)	ACHD [a] RACT (lb/MMBtu)
Boiler No.1 74 MMBtu/hr	Natural Gas	0.10	0.036[c]
Boiler No 3 128 MMBtu/hr	Natural Gas	0.10	0.036[c]
	Fuel oil [b]	0.12	
Boiler No.5 74 MMBtu/hr	Natural Gas	0.10	0.036[c]
Boiler No.6 179 MMBtu/hr	Natural Gas	0.10	0.036[c]
	Fuel oil [b]	0.12	
Boiler No.7 188 MMBtu/hr	Natural Gas	0.10	0.10[d]
	Fuel oil [b]	0.12	0.12[d]
Boiler No.8a 87 MMBtu/hr	Natural Gas	0.10	0.055

(a) Detailed RACT requirements are provided in Table S3.
(b) The Title V operating permit, issued December 18, 2013, restricts B003 operating hours when firing fuel oil to 850 gallons per hour and 500 hours per year. B006 is restricted to 1280 gallons fuel oil per hour and 640,000 gallons per year. B007 is restricted to 1340 gallons fuel oil per hour and 670,000 gallons per year.
(c) ACHD considers meeting an emission rate of 0.036 lb/MMBtu of NOx to be considered achievable with the installation of LNB + FGR; detailed analysis below shows these technologies to be cost effective.
(d) The detailed economic analysis shown in Table 5 below shows all technologically feasible control technologies to be cost-prohibitive. The affordability is impacted by the units capacity restriction (i.e., 411,720 MMBtu/hr) shown in Table 2 below. Baseline emissions of 0.14 lb/MMBtu requested by BBP are above the PA proposed presumptive RACT limits. Therefore, the RACT limits are the same as the PA proposed presumptive RACT limits (0.10 lb/MMBTU using natural gas and 0.12 lb/MMBTU using fuel oil).

Table S3. Conditions Considered to be RACT.

Unit Description	Current **and New** Permit Conditions
Boiler No.1 74 MMBtu/hr	• Burn only natural gas. • Natural gas input limited to 71,984 scf/hr and 630.58 MMscf/yr. • **NEW: Conduct tune-ups annually.** • **NEW: Install and operate LNB+FGR, NOx emissions is limited to 0.036 lb/MMBtu and 11.8 tpy.**
Boiler No 3 128 MMBtu/hr	• Burn only No.2 fuel oil with a max. sulfur content of 0.05%. • Annual average heat input of natural gas burner is limited to 64 MMBtu/hr or 560,640 MMBtu/yr. • Fuel oil input to the boiler is limited to 850 gallons/hr and/or 425,000 gallons/yr. • Limit operating hours when firing fuel oil to 500 hrs/yr. • **NEW: Conduct tune-ups annually.**[(a)] • **NEW: Install and operate LNB+FGR, NOx emissions is limited to 0.036 lb/MMBtu and 10.2 tpy.**
Boiler No.5 74 MMBtu/hr	• Burn only natural gas. • Natural gas input limited to 72,000 scf/hr and 630.72 MMscf/yr. • **NEW: Conduct tune-ups annually.** • **NEW: Install and operate LNB+FGR, NOx emissions is limited to 0.036 lb/MMBtu and 11.8 tpy.**
Boiler No.6 179 MMBtu/hr	• Burn only No.2 fuel oil with a max. sulfur content of 0.05%. • Annual average heat input of natural gas burner is limited to 174,125 scf/hr and 1,440 MMscf/yr. • Fuel oil input to the boiler is limited to 1,280 gallons/hr and 640,000 gallons/yr. • Limit operating hours when firing fuel oil to 500 hrs/yr. • **NEW: Conduct tune-ups annually.** [(a)] • **NEW: Install and operate LNB, NOx emissions is limited to 0.036 lb/MMBtu and 28.6 tpy.**
Boiler No.7 188 MMBtu/hr	• Burn only No.2 fuel oil with a max. sulfur content of 0.05%. • Annual average heat input is limited to 50% of capacity. • Natural gas input limited to 184,320 scf/hr and 372 MMscf/yr. • Fuel oil input to the boiler is limited to 1,340 gallons/hr and 670,000 gallons/yr. • Limit operating hours when firing fuel oil to 500 hrs/yr. • **NEW: Conduct tune-ups annually.** [(a)] • **NEW: Limited to the PA Presumptive RACT limits of 0.10 lb/MMBTU when combusting natural gas and 0.12 lb/MMBTU when combusting fuel oil.**
Boiler No.8a 87 MMBtu/hr	• Burn only natural gas. • **NEW: Conduct tune-ups annually.**

Where, LNB=Low NOx Burner, FGR=Flue Gas Recirculation, SCR=Selective Catalytic Reduction; MMscf=million standard cubic feet.

(a) Boilers 3, 6, and 7 currently require tune-ups every 5 years as required by the Boiler Area Source Rule, 40 CFR 63, Subpart JJJJJJ.

RACT Evaluations

RACT is "the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility." (44 FR 53761, 9/17/1979)

ACHD provided the following guidance to the major sources of NO_x and VOC in Allegheny County for performing the RACT analyses:

1. The analysis shall address all reasonably possible controls of VOCs and NO_x including changes in operation and work practices.

2. All control technology that is found to be technically infeasible must be accompanied by detailed and documented reason(s) as to why the technology is not feasible. General statements about the non-applicability of control technology to your industry will not be sufficient.

3. All changes in operation and work practices that are found not to be feasible require the same documentation as the controls in step #2 above.

4. All feasible control technology, changes in operation, work practices, etc. that are found to be cost prohibitive require a cost analysis demonstrating the cost per ton of pollutant controlled.

5. The analysis shall be done according to the procedures in EPA's OAQPS Cost Manual, EPA's cost spreadsheets are recommended where applicable. The manual and spreadsheets may be found on the CATC/RBLC web page on EPA's Technology Transfer Network (TTN) at http://www.epa.gov/ttn/catc/.

6. All data used in cost estimates, such as exhaust flow rates or the amount of ductwork used need proper documentation. If vendor quotes are used in the analysis for equipment costs, they are required to be supplied. Old analyses increased for inflation will not be acceptable. VATAVUK Air Pollution Control Cost Indexes shall be used with the aforementioned cost spreadsheets.

Each RACT analysis section is organized by the following 4 steps, which incorporate the guidance elements provided by Allegheny:

Step 1 – Identify Control Options (guidance element 1)
Step 2 – Eliminate Technically Infeasible Control Options (guidance elements 2 and 3)
Step 3 – Evaluate Control Options, including costs and emission reductions (guidance elements 4, 5, and 6)
Step 4 – Select RACT (guidance element 1)

Source/Process Description

The Bellefield Boiler Plant (BBP), located at Pittsburgh, is a captive steam generation facility. BBP is a major source of NO_x but is not a major source of VOCs. Descriptions of each source of NO_x emissions are provided in Table 1.

Table 1. NO_x Emission Units at the BBP

Unit ID	Description	Control Device	Fuel	Capacity
No.1	Boiler	None	Natural gas	74 MMBtu/hr
No.3	Boiler	None	Natural gas; No.2 fuel oil[(a)]	128 MMBtu/hr (119 MMBtu/hr oil)
No.5	Boiler	None	Natural gas	74 MMBtu/hr
No.6	Boiler	FGR[(b)]	Natural gas; No.2 fuel oil[(a)]	179 MMBtu/hr
No.7	Boiler	LNB[(b)]	Natural gas; No.2 fuel oil[(a)]	188 MMBtu/hr
EG-A & B	Emergency generators	None	Diesel	5.4 MMBtu/hr each (771 HP / 500 kW, each)
No. 8a	Boiler (rental unit)	LNB	Natural gas	87 MMBtu/hr

(a) The Title V operating permit, issued December 18, 2013, restricts operating hours when firing fuel oil to 500 hours per year.

(b) BBP RACT analysis dated March 14 2014, included vendor budgetary quotes for low-NOx burner (LNB) with flue gas recirculation (FGR) on each of boilers No.1, 3, 5, 6, and 7. BBP stopped burning coal in 2009. It is assumed that existing controls (i.e., FGR installed on boiler No.6 and LNB installed on boiler No.7) were designed to accommodate coal-firing; the combustion system has changed significantly, and those controls are no longer effective.

RACT Analyses in this Document

This source is a major source of NO_x, but is not a major source of VOCs; therefore, only NO_x RACT analyses have been conducted and are provided in this document.

RACT analyses for NOx have been conducted for boilers No.1, 3, 5, 6, 7, and 8a.

It should be noted that boilers No. 3, 6, and 7 have the ability to fire fuel oil. BBP has indicated that fuel oil is only used in the event of an emergency.[1] Permit restrictions limit fuel oil to 500 hours annually and usage only during emergencies (e.g., natural gas curtailment, gas supply interruption), maintenance (which cannot exceed 48 hour per year), and periodic testing and startups. The RACT analysis does not distinguish these boilers by fuel because natural gas is the primary fuel for all boilers.

ACHD has determined that it is not necessary to conduct a RACT evaluation for the emergency generators. This decision was made based on the relatively low potential emissions from these units. These units are subject to ACHD Article XXI Section 2105.06.d.6 which requires the equipment to be operated and maintained according to manufacturer's specification. ACHD considers it unlikely that additional controls would be technically and economically feasible for these combustion units. Each emergency generators usage is limited to 40 gallons/hour and 20,000 gallons/yr.

[1] BBP RACT analysis dated March 14 2014, includes this statement: "In addition, please note that this RACT re-evaluation does not consider NO_x from the fuel oil burning in Boilers 3, 6, and 7 because fuel oil is used only for emergency purposes."

RACT for NO_x – Boilers No.1, 3, 5, 6, 7, and 8a

BBP operates six (6) boilers (No.1, 3, 5, 6, 7, 8a). All exhaust gases exit through a common 256 foot exhaust stack No.2. In 2009, BBP formally requested that coal be deleted as an authorized fuel for boilers No.1, 3, and 5.[2] Each boiler is described briefly below:

(a) Boiler No.1 has a capacity of 74 MMBtu/hr while firing natural gas, was designed by Babcock & Wilcox and was originally installed in 1957. It was originally designed as coal and gas-fired chain grate boilers.[3]

The Title V operating permit, issued December 18, 2013, limits NO_x emissions from boiler No.1 as follows:

- Condition V.A.1.b, when natural gas is burned, to 0.92 lb/MMBtu;
- Condition V.A.1.c, restrict natural gas firing to 71,984 scf and 630.58 million standard cubic feet per year (MMscf/yr)
- Condition V.A.1.d, when natural gas is burned, to 68.08 lb/hr;
- Condition V.A.1.d, when natural gas is burned, to 298.19 tons/year; and
- Condition V.A.1.e, restricts the boiler from using any fuel other than natural gas.

(b) Boiler No.3 has a capacity of 128 MMBtu/hr while firing natural gas, was designed by Erie City and was originally installed in 1977. It was originally designed as a coal and gas-fired chain grate boiler.[4]

The Title V operating permit, issued December 18, 2013, limits NO_x emissions from boiler No.3 as follows:

- Condition V.B.1.c, independent of fuel burned, to 0.63 lb/MMBtu;
- Condition V.B.1.d, restrict natural gas firing to 64 MMBtu/hr (i.e., 50% of capacity) or 560,640 MMBtu/yr;
- Condition V.B.1.e, restrict natural gas to 124,515 scf/hr and/or 520 MMscf/yr;
- Condition V.B.1.f, restrict fuel oil to 850 gallons/hr and/or 425,000 gallons/yr;
- Condition V.B.1.f, burn only No.2 fuel oil with a max. sulfur content of 0.05%;
- Condition V.B.1.g, restricts operating hours when firing fuel oil to 500 hrs/yr;
- Condition V.B.1.k, when natural gas is burned, to 80.64 lb/hr;
- Condition V.B.1.k, when fuel oil is burned, to 74.97 lb/hr; and
- Condition V.B.1.k, independent of fuel burned to 167.80 tons/yr.

Boiler No. 3 is not subject to 40 CFR Part 63 Subpart JJJJJJ (National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers) because it is considered a gas fired boiler. However, Boiler No. 3 is capable of firing No. 2 fuel oil for emergency gas curtailment or gas interruption and therefore subject to Subpart JJJJJJ, Table 2, which requires tune-ups every 5 (five) years.

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[2] BBP – Title V Permit 0047 – Revision Request. Submitted to ACHD on February 27, 2009.
[3] Boiler No.1,3,5,6 and 7 Test Report Prepared by Air/Compliance Consultants, Inc. Testing Dates: October 13 through 17, 2008 and November 14, 2008. Submitted to ACHD on January 14, 2009.
[4] Boiler No.1,3,5,6 and 7 Test Report Prepared by Air/Compliance Consultants, Inc. Testing Dates: October 13 through 17, 2008 and November 14, 2008. Submitted to ACHD on January 14, 2009.

(c) Boiler No.5 has a capacity of 74 MMBtu/hr while firing natural gas, was designed by Erie City and was installed in 1965. It was originally designed as a coal and gas-fired chain grate boiler.[5]

The Title V operating permit, issued December 18, 2013, limits NO_x emissions from boiler No.5 as follows:
- Condition V.C.1.b, when natural gas is burned, to 0.59 lb/MMBtu;
- Condition V.C.1.c, restrict natural gas to 72,000 scf/hr and 630.72 MMscf/yr;
- Condition V.C.1.d, restrict the boiler from using any fuel other than natural gas;
- Condition V.C.1.e, when natural gas is burned, to 43.66 lb/hr; and
- Condition V.C.1.e, when natural gas is burned, to 191.23 tons/year.

(d) Boiler No.6 has a capacity of 179 MMBtu/hr while firing natural gas, was designed by Erie City/Zurn package boiler originally installed in 1965 and equipped with FGR for NOx control.

The Title V operating permit, issued December 18, 2013, limits NO_x emissions from boiler No.6 as follows:
- Condition V.D.1.d, independent of fuel burned, to 0.28 lb/MMBtu;
- Condition V.D.1.e, restrict natural gas to 174,125 scf/hr and/or 1,440 MMscf/yr;
- Condition V.D.1.f, restrict fuel oil to 1,280 gallons/hr and/or 640,000 gallons/yr;
- Condition V.D.1.f, burn only No.2 fuel oil with a max. sulfur content of 0.05%;
- Condition V.D.1.g, restricts operating hours when firing fuel oil to 500 hours per year;
- Condition V.D.1.m, independent of fuel burned, to 50.12 lb/hr; and
- Condition V.D.1.m, independent of fuel burned to 207.0 tons/year.

Boiler No. 6 is not subject to 40 CFR Part 63 Subpart JJJJJJ (National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers) because it is considered a gas fired boiler. However, Boiler No. 6 is capable of firing No. 2 fuel oil for emergency gas curtailment or gas interruption and therefore subject to Subpart JJJJJJ, Table 2, which requires tune-ups every 5 (five) years.

(e) Boiler No.7 has a capacity of 188 MMBtu/hr while firing natural gas, was designed by IBW Volcano boiler originally installed in 1994 and equipped with a LNB for NOx control. Boiler No.7 is equipped with O_2 and NO_2 Continuous Emission Monitors (CEMS).

The Title V operating permit, issued December 18, 2013, limits NO_x emissions from boiler No.7 as follows:
- Condition V.E.1.a, restricts operating hours to 4,032 hours/yr;
- Condition V.E.1.b, restrict boiler utilization to 50% of capacity during any consecutive 12-month period;
- Condition V.E.1.g, independent of fuel burned, to 0.20 lb/MMBtu;
- Condition V.E.1.h, restrict natural gas to 184,320 scf/hr and 372 MMscf/yr;
- Condition V.E.1.i, restrict fuel oil to 1,340 gallons/hr and/or 670,000 gallons/yr;
- Condition V.E.1.j, restricts operating hours when firing fuel oil to 500 hours per year;

[5] *Id*.

- Condition V.E.1.q, when natural gas is burned, to 38.0 lb/hr;
- Condition V.E.1.q, when fuel oil is burned, to 37.60 lb/hr; and
- Condition V.E.1.q, independent of fuel burned to 38.00 tons/year.

Boiler No. 7 is not subject to 40 CFR Part 63 Subpart JJJJJJ (National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers) because it is considered a gas fired boiler. However, Boiler No. 7 is capable of firing No. 2 fuel oil for emergency gas curtailment or gas interruption and therefore subject to Subpart JJJJJJ, Table 2, which requires tune-ups every 5 (five) years.

(f) Boiler No.8a has a capacity of 87 MMBtu/hr. This boiler is only permitted to combust natural gas. Boiler 8a is a placeholder in the operating permit which gives BBP permission to rent a boiler to supply steam during peak periods in the winter. BBP has committed to only renting a boiler equipped with a low-NOx burner.

The Title V operating permit, issued December 18, 2013, limits NO_x emissions from boiler No.8a as follows:

- Condition V.F.1.e, independent of fuel burned, to 0.055 lb/MMBtu at 3% O_2;
- Condition V.F.1.h, independent of fuel burned, to 4.80 lb/hr; and
- Condition V.F.1.h, independent of fuel burned to 20.90 tons/year.

As part of the RACT submittal, BBP requested emission rates for the boilers and provided annual maximum potential heat inputs for the boilers. Because the NO_x permit limits for several of the boilers were established based on burning coal and coal is no longer burned at BBP, new baseline emissions are necessary to reflect the emissions while burning natural gas. The source provided emission rates for each boiler based on the highest test results from the 2012 performance testing, increased by 50% as a worst-case assumption. These are shown in Table 2 below:

Table 2. Maximum Heat Input and Baseline NOx Emission Rates

Unit	Baseline NOx Emission Rates (lb/MMBtu)	Annual Maximum Potential Heat Input (MMBtu/year)
Boiler No. 1	0.15	648,240
Boiler No. 3	0.20	560,640
Boiler No. 5	0.18	648,240
Boiler No. 6	0.15	1,568,040
Boiler No. 7	0.14	411,720
Boiler No. 8a	0.055[(a)]	762,120

(a) BBP did not provide a baseline emission rate for Boiler No.8a. The emission rate shown is consistent with the permit limit.

<u>Step 1 – Identify Control Options</u>

ACHD reviewed BBP's RACT submittal for the six (6) boilers; consulted EPA's Alternative Control Techniques (ACT) document for Industrial/Commercial/Institutional (ICI) Boilers;[6] and

[6] Alternative Control Techniques (ACT) Document – NO_x Emissions from Industrial/ Commercial/ Institutional (ICI) Boilers (EPA-453/R-94-022). http://www.epa.gov/ttncatc1/dir1/icboiler.pdf, accessed January 23, 2015.

investigated additional resources to determine if any other ICI boiler controls have been demonstrated since 1994 when the ACT was published.

The table below presents the controls identified from the ACT. No additional control measure was identified for ICI boilers, except for combinations of controls listed below. These control measures have been organized into five groups: combustion optimization, staged combustion, additions to combustion air or fuel, low-NO_x burners, and post combustion controls.

Table 3. Boilers 1, 3, 5, 6, 7, and 8a – All NO_x Control Options

Category	Control Option
Combustion Optimization	Reduced air preheat (RAP)
	Combustion Optimization or Tune-up
	Low Excess Air (LEA)
Staged Combustion	Air Staging
	Fuel Staging
	Fuel Reburning
Additions To Combustion, Air or Fuel	Flue Gas Recirculation (FGR)
	Water / Steam Injection (WSI)
	Fuel Induced Recirculation (FIR)
Low-NO_x Burning	Low-NO_x Burner (LNB)
Post Combustion Control	Selective Catalytic Reduction (SCR)
	Selective Non-Catalytic Reduction (SNCR)

There are additional control techniques that could potentially be used by boilers, but these are either uncommon or not commercially demonstrated for ICI. These techniques include using oxygen instead of air, catalytic combustion, injection of oxidant, non-thermal plasma, and adsorption/absorption.

Combustion Optimization

Boiler operation can be optimized to reduce NO_x emissions by modifying boiler control settings. Sources can conduct a combustion optimization evaluation to determine the optimal settings for operating the boiler to address NO_x emissions, as well as other factors. Alternatively, sources can specifically reduce the air preheat and/or the level of excess air to reduce NO_x.

(a) Reduced air preheat

Air preheat is used to increase furnace thermal efficiency. Coal-fired stoker boilers with heat input capacities greater than 100 MMBtu/hr tend to have air preheaters. Air preheat has an adverse effect on NO_x emissions. The level of combustion air preheat has a direct effect on the temperatures in the combustion zone, which in turn, has a direct impact on the amount of thermal NO_x formed.

Available emissions data for RAP is limited, but the data shows a reduction of preheated combustion air temperature reduced NO_x by 32%.[7]

(b) Combustion Optimization or Tune-up

[7] Alternative Control Techniques (ACT) Document – NO_x Emissions from Industrial/ Commercial/ Institutional (ICI) Boilers (EPA-453/R-94-022). http://www.epa.gov/ttncatc1/dir1/icboiler.pdf, accessed January 12, 2015.

Combustion optimization involves conducting an evaluation of existing equipment (such as oxygen probes and other instrumentation, burners, dampers, tilt mechanisms. Heat transfer surfaces, and actuators) and determining if equipment needs to be cleaned or repaired. Also, combustion optimization includes conducting various tests to collect data on the boilers operation. This data is then analyzed to determine the combination of settings that result in optimal combustion with respect to NO_x and CO emissions, opacity, efficiency, and sustainable operation of the boiler (i.e., elimination of combustion operations that excessively deteriorate the boiler).

Because of the large number of control parameters, computer software is usually used to analyze the boiler data collected and aid in determining the optimal settings. Computer programs can also be used to operate the boiler, to make small adjustments to the boiler control parameters in real time to respond to changing factors (e.g. fuel characteristics, fuel flow, temperature).

Performing combustion optimization can improve the NO_x emissions by 5 to 40 percent for coal-fired boilers.[8] The actual NO_x emission rate achieved is dependent on the difference between the optimal settings and the boiler settings being used before optimization.

In a study by North Carolina State University on the effect of tune-ups on state operated boilers,[9] it was found that 1 to 5% fuel savings could be achieved. Although the effect on emissions was not reported, an emission decrease of 1 to 5% would have occurred based on the use of less fuel. However, additional NOx and CO emission reductions would be expected above those associated with efficiency improvements. It is difficult to predict the overall reduction in emissions that tune-ups can achieve because the pre-tune-up status is unknown. For these calculations, a reduction of 2% will be used where applicable.

(c) Low Excess Air (LEA)

LEA, also referred to as oxygen trim, is a burner optimization strategy in which the furnace is operated at the lowest excess air level that provides efficient, reliable, safe, and complete combustion. The reduction in excess air typically reduces NO_x emissions by 10% (in natural gas-fired units), reduces the total flue gas flow, and improves heat transfer.[10] One notable advantage of this strategy is that no significant capital expenses for new or modified hardware are required.

With LEA, incomplete combustion may occur resulting in an increase in carbon content of boiler ash, a decrease in energy efficiency, a decrease in steam temperature, and a significant increase in CO emissions when the O_2 content is less than 1%. Without a strict control system, these characteristics can also lead to slagging and corrosion, opacity concerns, and fires in air preheaters and ash hoppers.

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[8] Romero, Carlos El, Nenad Sarunac, Edward K. Levy, Combustion Optimization: Part II – Results of Fields Studies, Energy Research Center, Lehigh University.
[9] Eckerlin, Dr. Herbert M. and Eric W. Soderberg, USI Boiler Efficiency Program: A Report Summarizing the Findings and Recommendations of an Evaluation of Boilers in State Operated Facilities. Prepared for the State Energy Office, NC Department of Administration. Revised 2/25/04.
[10] Cleaver Brooks. Boiler Emission Guide - Reference Guide, 3rd Edition. Thomasville, GA: 2010. http://www.cleaverbrooks.com/uploadedFiles/Internet_Content/Reference_Center/Insights/Boiler%20Emissions%20Guide.pdf, accessed January 23, 2015.

Staged Combustion

Staged combustion relies on the reduction of the peak flame zone oxygen level to reduce formation of fuel NO_x and is achieved by delaying or staging the addition of combustion air.

(d) Air Staging

Air staging can be carried out using overfire air (OFA) or two-stage combustion. With air staged combustion, the combustion air is controlled and distributed to the combustion process to create different zones. By distributing the air and staging the combustion, the flame temperature is reduced, which reduces the NO_x created. In the first zone, the air is sparingly distributed to create an initial sub-stoichiometric, fuel rich zone. In the second zone above the first, the air is generously introduced to complete the combustion in a high excess air, low temperature zone, reducing thermal NO_x formation.

(e) Fuel Staging

Staged fuel combustion can be accomplished using burners out of service (BOOS), biasing the fuel flow to burners (a.k.a., biased firing), and fuel re-burning. These methods create different zones of fuel burning, such as fuel rich and fuel lean zones, within the furnace by shutting off fuel flow, diverting fuel from specific burners, or by controlling air and fuel injection zones. Separating the combustion zones reduces the flame temperature, thereby reducing NO_x. BOOS and biasing the fuel flow to burners cannot be conducted on boilers with only one burner because these are techniques that use multi-burners. Staged fuel combustion can achieve up to 50% NO_x reduction.

(g) Fuel Re-burn

Fuel re-burning is a staged fuel combustion technique where fuel is introduced downstream of the primary combustion chamber in a boiler to create a secondary combustion zone. However, with fuel re-burning, the NO_x formed in the primary combustion area is destroyed in the re-burn area. The fuel added can be any type of fuel but most experience is with natural gas. Emission reductions of 35 to 60% are possible.[11]

Additions to Combustion Air or Fuel

Boiler operation can be optimized to reduce NO_x emissions by injecting flue gases, water, steam, oxygen, or other materials into the combustion zone or the fuel. This controls the formation of NO_x by controlling the stoichiometric ratio of the chemicals that react to form NO_x. The addition of flue gas, water, or steam dilutes the combustion zone and reduces the combustion temperature, which in turn reduces the formation of thermal NO_x. The addition of oxygen (in place of air) in the combustion chamber essentially displaces the nitrogen available for NO_x formation.

(g) Flue Gas Recirculation (FGR)

FGR consists of recycling a portion of the flue gas back to the primary combustion zone. Injecting the inert flue gas in the primary combustion zone

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[11] Northeast States For Coordinated Air Use Management (NESCAUM), and Praveen Amar. Applicability and Feasibility of NO_x, SO_2, and PM Emissions Control Technologies for Industrial Commercial, and Institutional Boilers. November, 2008 (Revised January 2009). http://www.nescaum.org/documents/ici-boilers-20081118-final.pdf, accessed January 23, 2015.

lowers the peak flame temperatures in the primary combustion zone and thereby lowers thermal NO_x formation. In addition, the flue gas lowers the oxygen concentration in the primary combustion zone and thereby lowers thermal NO_x.

Coal-fired boilers often use FGR to control the steam temperature. Flue gas is added to the boiler through the furnace hopper or above the windbox in coal boilers. This is not an effective NO_x control. The flue gas must be introduced into the windbox to affect the thermal NO_x emissions. FGR through the windbox can only affect the thermal NO_x emission. Because coal has a significant amount of nitrogen in the fuel, much of the NO_x emissions from coal-fired boilers are from fuel NO_x; therefore, FGR is not considered an effective NO_x reduction technique for coal-fired boilers since it does not reduce fuel NO_x.

FGR reduces emissions of NO_x in a natural gas boiler by about 53 to 74%.[12]

(h) Water / Steam Injection (WSI)

While somewhat effective in oil-fired and coal-fired boilers, WSI has been utilized more effectively in natural gas-fired boilers and combustion turbines.

With this technique, water or steam is injected into the primary combustion zone to reduce the formation of thermal NO_x, but not fuel NO_x, by decreasing the peak combustion temperature. More specifically, water injection decreases the peak flame temperature by diluting the combustion gas stream and acting as a heat sink by absorbing the heat necessary to vaporize the water (latent heat of vaporization) and raise the vaporized water temperature to the combustion temperature. WSI reduces NO_x emissions by as much as 80% (in natural gas-fired units).[13]

(i) Fuel Induced Recirculation (FIR)

FIR is a combustion control used in natural gas boilers. With FIR, flue gas is recirculated and mixed with the fuel. This technique cools the flame temperature similarly to how FGR reduces the temperature and thermal NO_x. However, FIR also reduces prompt NO_x. Prompt NO_x is from the oxidation of compounds formed from reactions between atmospheric nitrogen and radicals formed in the combustion of fuel. For example, nitrogen monohydride, hydrogen cyanide, and other compounds can form during combustion and then be oxidized to nitric oxide.

Low-NO_x Burning

Low-NO_x burners emit less NO_x than conventional burners. They are usually designed to incorporate one of the combustion control techniques within the burner, such as staged combustion, flue gas recirculation, fuel induced recirculation, low excess air, or a combination of these techniques. In all cases, the NO_x emissions are controlled by lowering combustion zone temperatures to reduce the production of NO_x.

(j) Low-NO_x Burner (LNB)

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[12] Alternative Control Techniques (ACT) Document – NO_x Emissions from Industrial/ Commercial/ Institutional (ICI) Boilers (EPA-453/R-94-022). http://www.epa.gov/ttncatc1/dir1/icboiler.pdf, accessed January 12, 2015.
[13] Cleaver Brooks. Boiler Emission Guide - Reference Guide, 3rd Edition. Thomasville, GA: 2010. http://www.cleaverbrooks.com/uploadedFiles/Internet_Content/Reference_Center/Insights/Boiler%20Emissions%20Guide.pdf, accessed January 23, 2015.

LNB is a relative term that refers to a burner design in which the supplied fuel and air are staged across the burner. It is relative in the sense that a LNB in a furnace that is several decades old may have a NO_x emission rate of approximately 50 ppm, while a LNB on a new boiler may have a NO_x emission rate of less than 30 ppm.[14]

The staging results in fuel-lean and fuel-rich combustion zones in the furnace at the burner. In the fuel-lean zones, the combustion temperature is lowered, reducing the production of NO_x emissions. Both the temperature and oxygen concentrations are lowered in the fuel-rich zones. LNB technology is available from many manufacturers and applicable to all fuels. Retrofitting older boilers with newer LNB can be technically feasible but comes at a high capital cost. Low-NO_x burners achieve 32 to 71% reduction.[15]

Post Combustion Control

Post combustion control includes the addition of technologies that reduce NO_x emissions (as opposed to preventing NO_x generation). Generally, these technologies include the addition of a catalyst or reactant into the exhaust stream which chemically reduces the NO_x, allowing for removal from the gas stream.

(k) Selective Catalytic Reduction (SCR)

SCR controls NO_x emissions by promoting the conversion of NO_x into molecular nitrogen and water vapor using a catalyst. NH_3, usually diluted with air or steam, is injected into the exhaust upstream of a catalyst bed. On the catalyst surface, NH_3 reacts with NO_x to form molecular nitrogen and water with the following basic reaction pathways:

$$4NH3 + 4NO + O2 \rightarrow 4N2 + 6H2O$$
$$8NH3 + 6NO2 \rightarrow 7N2 + 12H2O$$

Depending on system design, NO_x removal of 70-90% can be achieved under optimum conditions.[16]

The catalyst serves to lower the activation energy of these reactions, which allows the NO_x conversions to take place at a lower temperature than the exhaust gas. The optimum temperatures can range from 350°F to 1,100°F but are typically designed to occur between 600°F and 750°F, depending on the catalyst.[17] Typical SCR catalysts include metal oxides (titanium oxide and vanadium), noble metals (combinations of platinum and rhodium), zeolite (alumino-silicates), and ceramics. Water vapor and elemental nitrogen are released to the atmosphere as part of the exhaust stream.

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[14] Cleaver Brooks. Boiler Emission Guide - Reference Guide, 3rd Edition. Thomasville, GA: 2010. http://www.cleaverbrooks.com/uploadedFiles/Internet_Content/Reference_Center/Insights/Boiler%20Emissions%20Guide.pdf, accessed January 23, 2015.
[15] Alternative Control Techniques (ACT) Document – NO_x Emissions from Industrial/ Commercial/ Institutional (ICI) Boilers (EPA-453/R-94-022). http://www.epa.gov/ttncatc1/dir1/icboiler.pdf, accessed January 12, 2015.
[16] The Babcock & Wilcox Company. Steam Its Generation and Use, 40th Edition. Ed. S C Stultz and J B Kitto. Barberton, Ohio: 1992
[17] California Environmental Protection Agency - Air Resources Board, and Stephanie Kato. Report to the Legislature: Gas-Fired Power Plant NO_x Emission Controls and Related Environmental Impacts. May: 2004.

Factors affecting SCR performance include space velocity (volume per hour of flue gas divided by the volume of the catalyst bed), ammonia/NO_x molar ratio, and catalyst bed temperature. Space velocity is a function of catalyst bed depth. Decreasing the space velocity (increasing catalyst bed depth) will improve NO_x removal efficiency by increasing residence time but will also cause an increase in catalyst bed pressure drop.

Reaction temperature is critical for proper SCR operation. Below the minimum temperature, reduction reactions will not proceed. At temperatures exceeding the optimal range, oxidation of ammonia will take place resulting in an increase in NO_x emissions.

SCR catalyst can be subject to deactivation by a number of mechanisms. Loss of catalyst activity can occur from thermal degradation, where the catalyst is exposed to excessive temperatures over a prolonged period of time. Catalyst deactivation can also occur due to chemical poisoning. Principal poisons include arsenic, sulfur, potassium, sodium, and calcium.

(l) Selective Non-Catalytic Reduction (SNCR)

Like SCR, SNCR operates by promoting the conversion of NO_x into molecular nitrogen and water vapor using urea or ammonia. However, unlike SCR, SNCR does not utilize a catalyst and therefore requires an exhaust of 1700-2000°F.[18]

Units with the above furnace exit temps, residence times less than 1-sec, and high levels of uncontrolled NO_x are good candidates for SNCR control. Depending on system design, NO_x removal of 30-50%.[19]

Step 2 – Eliminate Technically Infeasible Control Options

Each control option listed in Step 1 was evaluated to determine if it was a feasible control for boilers No.1, 3, 5, 6, 7, and 8a.

It was determined that SCR, LNB, and FGR are technically feasible for controlling boiler NO_x emissions for boilers No.1, 3, 5, 6, and 7. Tune-ups are considered technically feasible for boilers No. 1, 3, 5, 6, 7 and 8a.

Boiler 8a is a placeholder in the operating permit which gives BBP permission to rent a boiler to supply steam during peak periods in the winter. BBP has committed to only renting a boiler equipped with a low-NOx burner. ACHD considers FGR and SCR technically feasible for controlling boiler NO_x emissions for boiler No.8a.

These controls are economically evaluated in the next section.

A number of the control options identified are not technically feasible for controlling NO_x from the boilers. This section presents the rationale explaining why each control option is not, technically feasible.

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[18] Northeast States For Coordinated Air Use Management (NESCAUM), and Praveen Amar. Applicability and Feasibility of NO_x, SO_2, and PM Emissions Control Technologies for Industrial Commercial, and Institutional Boilers. November, 2008 (Revised January 2009). http://www.nescaum.org/documents/ici-boilers-20081118-final.pdf, accessed January 23, 2015.
[19] U.S. EPA. Air Pollution Control Technology Fact Sheet; Selective Non-Catalytic Reduction (EPA-452/F-03-031). 2003. http://www.epa.gov/ttncatc1/dir1/fsncr.pdf, accessed January 23, 2015.

(a) Reduced Air Preheat

RAP is limited to stokers equipped with combustion air preheaters.[20] It is assumed Boilers No.1, 3, 5, 6, and 7 do not have air preheaters. Therefore, RAP is removed from further consideration.

(b) LEA

Boilers No.1, 3, and 5 were constructed in 1957, 1977, and 1965, respectively. They were originally designed as coal-fired stoker chain-grate boilers and later retrofitted with natural gas burners. The boilers were originally designed to operate using relatively high excess air to ensure the coal was completely burned. The high amount of excess air was inherent in the original design; at the time it was considered an appropriate approach for enhancing complete combustion.

Achieving low excess air conditions would require a fundamental redesign of each boiler. Therefore, LEA is considered technically infeasible for controlling NO_x emissions.

(c) Air Staging / Fuel Staging

The ICI ACT states that staged burner flame lengths tend to be longer than those of conventional burners. There is the possibility that flame impingement can occur on the furnace walls, resulting in tube failure and corrosion. Additionally, staged burners are often wider and longer than conventional burners, requiring significant modifications to existing water-walls and windboxes.[21]

Although, specific information on boilers No.1, 3, 5, 6 and 7 internal sizes was not reviewed, it is expected that an older boiler would have these issues. Therefore, air staging and fuel staging are considered technically infeasible for controlling NO_x emissions. It should be noted that boiler No.6 is a packaged unit with a small combustion zone.

(d) Fuel Re-burn

Reburning has been chiefly developed and applied in coal-fired boilers. Typically, natural gas is introduced downstream of the primary combustion chamber to create a secondary combustion zone. Natural gas is an attractive re-burn fuel because it is nitrogen-free. Boilers No.1 and No.5 are natural gas-fired. Boilers No. 3, 6, and 7 only burn fuel oil during emergencies, maintenance, and periodic testing.

Furthermore, it is likely boilers No.1, 3, 5, 6, and 7 do not have enough height nor residence time to create partial and then final combustion zones. Therefore, fuel re-burn is considered technically infeasible for controlling NO_x emissions.

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[20] Alternative Control Techniques (ACT) Document – NO_x Emissions from Industrial/ Commercial/ Institutional (ICI) Boilers (EPA-453/R-94-022). http://www.epa.gov/ttncatc1/dir1/icboiler.pdf, accessed January 12, 2015.

[21] Alternative Control Techniques (ACT) Document – NO_x Emissions from Industrial/ Commercial/ Institutional (ICI) Boilers (EPA-453/R-94-022). http://www.epa.gov/ttncatc1/dir1/icboiler.pdf, accessed January 12, 2015.

(e) WSI

WSI has severe operational drawbacks, namely: reduced thermal efficiency, reduced steam production, and increased equipment corrosion. For these reasons, WSI has been primarily used on gas turbines where the reduction in thermal efficiency is much less than on a steam boiler. Therefore, WSI is considered technically infeasible for controlling NO_x emissions.

(f) FIR

EPA's RBLC (RACT-BACT-LAER Clearinghouse) shows only a single industrial sized natural gas-fired boiler equipped with an FIR for NO_x control over the last 10 years. [22] Therefore, FIR is removed from further consideration.

(h) SNCR

The appropriate SNCR temperature window is approximately 1600 to 2000°F. The exhaust temperature for boiler ranges from 275 to 500°F, which is much lower than the needed temperature of 1600 to 2000°F. Lower temperatures reduce the reaction rates and unreacted ammonia may slip through and be emitted from the stack. Therefore, SNCR is considered technically infeasible for controlling NO_x emissions.

<u>Step 3 - Evaluate Control Options</u>

Emissions and Emission Reductions

Collectively, boilers No.1, 3, 5, 6, 7, and 8a have a potential to emit (PTE) 330.4 tons/yr of NO_x based on the proposed emission limits included in BBP RACT submittals and shown in Table 2. This PTE is lower than the limits included in the Title V operating permit issued December 2013.

The emission reductions in Table 4 below are based on these proposed baseline emission limits.

The technically feasible control option with its estimated control efficiency is as follows:

[22] The following RBLC Codes were included in the search: 12.310 (Fuel Combustion; Industrial-Size Boilers/Furnaces size 100-250 MMBtu/hr; Natural Gas) and 13.310 (Fuel Combustion; Industrial-Size Boilers/Furnaces <100 and MMBtu/hr; Natural Gas.

Table 4. Boilers No. 1, 3, 5, 6, 7, and 8a – NO_x Technically Feasible Control Options

Control Type	Estimated NO_x [a] Control Efficiency	NO_x Emission Reductions (tons/yr)	Controlled NO_x Emissions (lb/MMBtu)
No.1 – LNB+FGR	76%	36.8	0.036 [b]
No.3 – LNB+FGR	82%	45.8	0.036 [b]
No.5 – LNB+FGR	80%	46.5	0.036 [b]
No.6 – LNB+FGR	76%	89.0	0.036 [b]
No.7 – LNB+FGR	74%	21.3	0.036 [b]
No.8a – LNB+FGR[c]	34%	7.07	0.036 [b]
No.1 – SCR	93%	45.4	0.010 [d]
No.3 – SCR	95%	53.3	0.010 [d]
No.5 – SCR	94%	55.1	0.010 [d]
No.6 – LNB+SCR	93%	109.8	0.010 [d]
No.7 – SCR	93%	26.8	0.010 [d]
No.8a – LNB+SCR[c]	82%	17.1	0.010 [d]
No.1 – Tune-up[e]	2%	1.0	0.15
No.3 – Tune-up[f]	-	-	-
No.5 – Tune-up[d]	2%	1.2	0.18
No.6 – Tune-up[f]	-	-	-
No.7 – Tune-up[f]	-	-	-
No.8a – Tune-up[d]	2%	0.4	0.055

(a) Control efficiencies were calculated from the permit limited PTE and the controlled NOx emission rate.
(b) Vendor guarantee exhaust concentrations were provided by BBP.
(c) Boiler No. 8a already has a LNB; therefore the cost and emission reductions are associated with adding the FGR or SCR.
(d) According to recent permit limits in the RBCL, boilers equipped with a SCR routinely achieve this emission rate.
(e) Percent reduction in fuel usage; therefore, the emissions on a MMBtu basis does not change.
(f) Tune-ups are required every 5 years by the Boiler Area Source Rule, 40 CFR 63, Subpart JJJJJJ.

Control efficiencies were calculated from: 1) the proposed limits discussed above (table 2), 2) exhaust concentrations guaranteed by the LNB and FGR vendor, [23] and 3) recent permit limits in the RBCL for a boiler equipped with a SCR.

Economic Analysis

Two boilers have existing NOx controls: specifically boiler No.6 has FGR and No.7 has LNB. It is BBP preference that these controls be replaced with new devices. BBP confirmed the rented Boiler 8a will have LNB. The RACT analysis dated March 14, 2014 included vendor budgetary quotes for LNB+FGR for each of boilers No.1, 3, 5, 6, and 7.

Using information provided by BBP and collected by ACHD, a thorough economic analysis was conducted - see Appendix A for more information. The analysis estimates the total costs associated with the NO_x control equipment, including the total capital investment of the various

[23] Vendor contacted by BBP required the installation of both a LNB and FGR to reach their guarantee of 30 ppmv (i.e., 0.036 lb/MMBtu)

components intrinsic to the complete system, the estimated annual operating costs, and the indirect annual costs. All costs, except for direct installation costs, were calculated using the methodology described in Section 6, Chapter 1 of the “EPA Air Pollution Control Cost Manual, Sixth Edition” (document # EPA 452-02-001). Direct capital cost is based on a vendor quote. Annualized costs are based on an interest rate of 7%, an equipment life of 15 years.

The basis of the cost-effectiveness, used to evaluate the control option, is the ratio of the annualized cost to the amount of NO_x (tons) removed per year. A summary of the cost determined in the analysis is provided in Table 5:

Table 5. Boilers No. No. 1, 3, 5, 6, 7, and 8a – Economic Analysis of NO_x Technically Feasible Control Options

Option	Total Capital Investment ($)	Total Annualized Cost ($/year)	Potential NO_x Removal from Add-on Control (ton/year)	Cost Effectiveness ($/ton NO_x removed)
No.1 – LNB+FGR	$725,000	$138,000	36.8	$3,700
No.3 – LNB+FGR	$725,000	$131,000	45.8	$2,900
No.5 – LNB+FGR	$725,000	$131,000	46.5	$2,800
No.6 – LNB+FGR	$725,000	$150,000	89.0	$1,700
No.7 – LNB+FGR[(a)]	$725,000	$150,000	21.3	$7,000
No.8a – LNB+FGR[(a)]	$520,000	$109,000	7.07	$15,400
No.1 – SCR	$1,089,000	$353,000	45.4	$7,800
No.3 – SCR	$1,348,000	$402,000	53.3	$7,500
No.5 – SCR	$910,000	$327,000	55.1	$5,900
No.6 –LNB+SCR	$1,341,000	$413,000	109.8	$3,800
No.7 –FGR+SCR	$1,860,000	$489,000	26.8	$18,300
No.8a – LNB+SCR[(a)]	$1,278,000	$382,000	17.1	$22,300
No.1 – Tune-up	$6,500	$2,000	1.0	$2,100
No.3 – Tune-up[(b)]	-	-	-	-
No.5 – Tune-up	$6,500	$2,000	1.2	$1,700
No.6 – Tune-up[(b)]	-	-	-	-
No.7 – Tune-up[(b)]	-	-	-	-
No.8a – Tune-up	$6,500	$2,000	0.4	$4,800

(a) High cost-effectiveness for Boilers No.7 and 8a are the result of two factors: 1) Low boiler usage and 2) Low baseline emissions. Usage (i.e. annual maximum potential heat input) and requested baseline emissions are included in Table 2 above. Low baseline emissions shrink the “Potential NOx removal from Add-on Control (ton/year) in Table 5.

(b) Tune-ups are required every 5 years by the Boiler Area Source Rule, 40 CFR 63, Subpart JJJJJJ.

Step 4 – Select RACT

Based on the costs shown in Table 5, the following are cost-effective NO_x control options:

- Installing a LNB+FGR for boilers No.1, 3, and 5;
- Installing a SCR for boiler No. 6; and
- Annual tune-up pursuant to the procedures of §2105.06.d.2 for boilers No. 1, 3, 5, 6, 7 and 8a.

Boilers No. 1 and 5:
The NOx RACT was determined for boilers No. 1 and 5 to be: 1) installation of LNB + FGR, 2) compliance with a new NO_x limit emission of 0.036 lb/MMBtu which is achievable with LNB + FGR, and 3) an annual tune-up pursuant to the provisions of §2105.06.d.2, which requires that the tune-up include, at a minimum:

- Inspection, adjustment, cleaning, or replacement of fuel-burning equipment, including the burners and moving parts necessary for proper operation as specified by the manufacturer;

- Inspection of the flame pattern or characteristics and adjustments necessary to minimize total emissions of NOx, and to the extent practicable minimize emissions of CO; and

- Inspection of the air-to-fuel ratio control system and adjustments necessary to ensure proper calibration and operation as specified by the manufacturer.

Additionally, the following records must be maintained for each adjustment conducted in the annual tune-up:

- The date of the adjustment procedure;
- The name of the service company and technicians;
- The operating rate or load after adjustment;
- The CO and NOx emission rates before and after adjustment;
- The excess oxygen rate after adjustment; and
- Other information required by the applicable operating permit.

The source may petition ACHD to reduce the frequency of the tune-ups to biennially, if there is not a significant change in the NOx and CO emission rate between subsequent years following a tune-up.

Boiler No. 3:
The NOx RACT was determined for boiler No. 3 to be 1) installation of LNB + FGR, 2) compliance with a new NO_x limit emission of 0.036 lb/MMBtu which is achievable with LNB + FGR, and 3)
an annual tune-up pursuant to the provisions of §2105.06.d.2, which requires that the tune-up include, at a minimum:

- Inspection, adjustment, cleaning, or replacement of fuel-burning equipment, including the burners and moving parts necessary for proper operation as specified by the manufacturer;

- Inspection of the flame pattern or characteristics and adjustments necessary to minimize total emissions of NOx, and to the extent practicable minimize emissions of CO; and

- Inspection of the air-to-fuel ratio control system and adjustments necessary to ensure proper calibration and operation as specified by the manufacturer.

Additionally, the following records must be maintained for each adjustment conducted in the annual tune-up:

- The date of the adjustment procedure;
- The name of the service company and technicians;
- The operating rate or load after adjustment;
- The CO and NOx emission rates before and after adjustment;
- The excess oxygen rate after adjustment; and
- Other information required by the applicable operating permit.

The source may petition ACHD to reduce the frequency of the tune-ups to biennially, if there is not a significant change in the NOx and CO emission rate between subsequent years following a tune-up.

Boiler No. 6:
The NOx RACT was determined for boiler No. 6 to be: 1) installation of SCR and LNB, 2) compliance with a new NO_x limit emission of 0.010 lb/MMBtu which is achievable with SCR, and 3) an annual tune-up pursuant to the provisions of §2105.06.d.2, which requires that the tune-up include, at a minimum:

- Inspection, adjustment, cleaning, or replacement of fuel-burning equipment, including the burners and moving parts necessary for proper operation as specified by the manufacturer;

- Inspection of the flame pattern or characteristics and adjustments necessary to minimize total emissions of NOx, and to the extent practicable minimize emissions of CO; and

- Inspection of the air-to-fuel ratio control system and adjustments necessary to ensure proper calibration and operation as specified by the manufacturer.

Additionally, the following records must be maintained for each adjustment conducted in the annual tune-up:

- The date of the adjustment procedure;
- The name of the service company and technicians;
- The operating rate or load after adjustment;
- The CO and NOx emission rates before and after adjustment;
- The excess oxygen rate after adjustment; and
- Other information required by the applicable operating permit.

The source may petition ACHD to reduce the frequency of the tune-ups to biennially, if there is not a significant change in the NOx and CO emission rate between subsequent years following a tune-up.

Boiler No. 7:

Based on the costs shown in Table 5, no technologically feasible controls are cost-effective. High cost-effectiveness is the result of two factors: 1) Low boiler usage and 2) Low baseline emissions. Usage (i.e. annual maximum potential heat input) and requested baseline emissions are included in Table 2 above. However, ACHD's RACT limits are no less stringent than those in the PA Presumptive RACT. Therefore, the RACT limits for this boiler are the same as the PA proposed presumptive RACT limits (0.10 lb/MMBTU using natural gas and 0.12 lb/MMBTU using fuel oil), and an annual tune-up pursuant to the provisions of §2105.06.d.2, which requires that the tune-up include, at a minimum:

- Inspection, adjustment, cleaning, or replacement of fuel-burning equipment, including the burners and moving parts necessary for proper operation as specified by the manufacturer;

- Inspection of the flame pattern or characteristics and adjustments necessary to minimize total emissions of NOx, and to the extent practicable minimize emissions of CO; and

- Inspection of the air-to-fuel ratio control system and adjustments necessary to ensure proper calibration and operation as specified by the manufacturer.

Additionally, the following records must be maintained for each adjustment conducted in the annual tune-up:

- The date of the adjustment procedure;
- The name of the service company and technicians;
- The operating rate or load after adjustment;
- The CO and NOx emission rates before and after adjustment;
- The excess oxygen rate after adjustment; and
- Other information required by the applicable operating permit.

The source may petition ACHD to reduce the frequency of the tune-ups to biennially, if there is not a significant change in the NOx and CO emission rate between subsequent years following a tune-up.

Boiler No. 8:
The NOx RACT was determined for boiler No. 8 to be an annual tune-up pursuant to the provisions of §2105.06.d.2, which requires that the tune-up include, at a minimum:

- Inspection, adjustment, cleaning, or replacement of fuel-burning equipment, including the burners and moving parts necessary for proper operation as specified by the manufacturer;

- Inspection of the flame pattern or characteristics and adjustments necessary to minimize total emissions of NOx, and to the extent practicable minimize emissions of CO; and

- Inspection of the air-to-fuel ratio control system and adjustments necessary to ensure proper calibration and operation as specified by the manufacturer.

Additionally, the following records must be maintained for each adjustment conducted in the annual tune-up:

- The date of the adjustment procedure;
- The name of the service company and technicians;
- The operating rate or load after adjustment;
- The CO and NOx emission rates before and after adjustment;

- The excess oxygen rate after adjustment; and
- Other information required by the applicable operating permit.

The source may petition ACHD to reduce the frequency of the tune-ups to biennially, if there is not a significant change in the NOx and CO emission rate between subsequent years following a tune-up.

EPA's RBLC determinations:
To put the selected RACT limits into a broader context, ACHD reviewed the EPA's RBLC determinations for natural gas boilers from over the last 5 years. Table 6 provides the RBLC findings. Specifically ACHD reviewed 6 RBLC Codes. RBLC code refers to the industrial sector, the boiler size, and fuel. The following RBLC codes were reviewed:

- 11.220 Utility and Large Industrial Size Boilers/Furnaces >250 MMBtu/hr; Distillate Oil,
- 11.310 Utility and Large Industrial Size Boilers/Furnaces >250 MMBtu/hr; Natural Gas,
- 12.220 Industrial Size Boilers/Furnaces between 100-250 MMBtu/hr; Distillate Oil,
- 12.310 Industrial Size Boilers/Furnaces between 100-250 MMBtu/hr; Natural Gas,
- 13.220 Commercial/Institutional Size Boiler/Furnaces <100 MMBtu/hr; Distillate Oil, and
- 13.310 Commercial/Institutional Size Boiler/Furnaces <100 MMBtu/hr; Natural Gas.

Table 6 shows that the expected emission rates for boilers equipped with either a SCR or LNB+FGR:

Table 6. EPA's RBLC Findings

Source	RBLC ID	Date of Permit Issuance	NO_x Limit (lb/MMBtu)	NO_x Control
13.31 – Gas Suwannee Mill [46 MMBtu/hr]	FL-0335	9/5/2012	0.0360	LNB+FGR
11.31 – Gas Georgia Pacific Breton, LLC [425 MMBtu/hr]	*AL-0271	6/11/2014	0.0200	LNB+FGR
13.31 – Gas St. Joseph Enegry Center, LLC [80 MMBtu/hr]	*IN-0158	12/3/2012	0.0320 (3 hours)	LNB+FGR
11.31 – Gas Iowa Fertilizer Company [472.4 MMBtu/hr]	IA-0105	10/26/2012	0.0125 (30 day rolling avg.)	LNB+FGR
11.31 – Gas Green River Soda Ash Plant [254 MMBtu/hr]	*WY-0074	11/18/2013	0.0110 (30 day rolling)	LNB+FGR
13.31 – Gas Thetford Generating Station [100 MMBtu/hr]	*MI-0410	7/25/2013	0.0500	LNB+FGR
12.31 – Gas Power County Advanced Energy Center [250 MMBtu/hr]	ID-0017	2/10/2009	0.0200	LNB+FGR
13.31 – Gas Harrah'S Operating Company, Inc. [14.34 MMBtu/hr]	NV-0049	8/20/2009	0.0353	LNB+FGR
11.31 – Gas Mgm Mirage [41.64 MMBtu/hr]	NV-0050	11/30/2009	0.0110	LNB+FGR

Table 6. EPA's RBLC Findings

Source	RBLC ID	Date of Permit Issuance	NO_x Limit (lb/MMBtu)	NO_x Control
13.31 – Gas Oregon Clean Energy Center [99 MMBtu/hr]	*OH-0352	6/18/2013	0.0200	LNB+FGR
13.31 – Gas Hess Newark Energy Center [589 MMBtu/hr]	NJ-0080	11/1/2012	0.0500	LNB+FGR
13.31 – Gas Concord Steam Corporation [76.8 MMBtu/hr]	NH-0015	2/27/2009	0.0320 (avg. 3 1-hr test runs)	LNB+FGR
13.31 – Gas Concord Steam Corporation [76.8 MMBtu/hr]	NH-0015	2/27/2009	0.0320 (avg. 3 1-hr test runs)	LNB+FGR
13.31 – Gas Harrah'S Operating Company, Inc. [16.8 MMBtu/hr]	NV-0049	8/20/2009	0.0300	LNB+FGR
13.31 – Gas Kenai Nitrogen Operations [50 MMBtu/hr]	*AK-0083	1/6/2015	0.0084 (3 hr avg. @15% O2)	SCR

SUPERVISING COMMITTEE OF THE

BELLEFIELD BOILER PLANT

4400 FORBES AVENUE

PITTSBURGH, PA 15213

(412) 622-3351

OFFICE OF THE CHAIRMAN

March 14, 2014

RECEIVED

MAR 14 2014

ALLEGHENY COUNTY HEALTH DEPT.
AIR QUALITY PROGRAM

Ms. Sandra Etzel, Chief Engineer
Allegheny County Health Department
Air Quality Program
301 39th Street
Building #7,
Pittsburgh, PA 15201

Subject: Bellefield Boiler Plant Nitrogen Oxide (NOx) Reasonably Available Control Technology (RACT) Re-Evaluation Request

Dear Ms. Etzel,

On December 6, 2013, Bellefield Boiler Plant (BBP) received a letter from the Allegheny County Health department (ACHD) requiring BBP to re-evaluate its Reasonably Available Control Technology (RACT) for its natural gas burning boilers. On December 24, 2013, BBP requested additional time to respond. On or about January 13, 2014, you extended the deadline to respond to March 14, 2014. This letter is BBP's submission in response.

Based on ACHD's requirements stated in the December 6, 2013 letter and as modified in a follow-up discussion between you and Mr. David Wagner of Reed Smith LLP, BBP's response is not a top-down RACT analysis, but instead focuses on an economic comparison of the current natural gas burners in Boilers 1, 3, 5, 6 and 7 with new low Nitrogen Oxides (NOx) burners capable of each achieving a NOx concentration of 30 ppmv. In using low-NOx Burners as the most feasible technology, our analysis compares the facility's existing burners to proposed low-NOx burners in combination with flue gas recirculation. BBP's August, 2006, NOx RACT Re-Evaluation showed that low-NOx burners and flue gas recirculation (necessary in combination to reach equipment manufacturer guarantees) are the only technically and potentially economically feasible candidate NOx control technologies for BBP's boilers.

As discussed below, BBP's NOx emission rates for each boiler are significantly lower than those contained in the NOx RACT Plan Approval and Order Upon Consent – and included in BBP's current Title V Air Operating Permit – and are based on what each boiler has been able to achieve since the facility's conversion to combustion of all natural gas. Since the conversion, each boiler has reduced NOx emissions by more than 50 percent.

In addition, please note that this RACT re-evaluation does not consider NOx from the fuel oil burning in Boilers 3, 6 and 7 because fuel oil is used only for emergency purposes.

Baseline NOx Emission Rates and Emission Factors

BPP's current boiler configuration and each boiler's potential natural gas use are summarized in Table 1.

Table 1 Current Boiler Configuration

Boiler No.	Fuel	Maximum Steam Rate (lb/hr x 10^3)	Efficiency (%) (1)	Design Natural Gas (NG) Heat Input (MMBtu/hr)	Annual Capacity Restriction	Potential NG Fuel Use (MMBtu/Year)
1	Natural Gas (NG)	68	81.4	74	100%	648,240
3	NG Primary/ Fuel Oil (FO) Backup	100	87.8	128	50%	560,640
5	NG	68	75	74	100%	648,240
6	NG Primary/ FO backup	150	84.1	179	100%	1,568,040
7	NG Primary/ FO Backup	150	80.2	188	25%	411,720

(1) Boiler efficiency = energy content of steam / energy content of fuel. Efficiencies for Boiler Nos. 1-5 are calculated from: Optimal Technologies, January 19, 1996, NOx Emission Testing. Efficiencies for Boiler Nos. 6 and 7 are from vendor specification. Oil efficiency for Boiler No. 6 is 87.48 percent. Oil efficiency for Boiler No. 7 is 83.42 percent. Oil efficiency for Boiler No. 3 is 85.2 Energy content of steam = 1,005.5 Btu/lb steam percent (from acceptance test data).

BBP conducted stack testing in October and November of 2012 with the boilers burning only natural gas. The test report is included in Attachment A. Based upon the test results the NOx emission rates were shown to be much lower than the limits in the current Title V permit. Table 2 compares the NOx emission rates and emission factors in the Title V permit to the emission rates and emission factors from the 2012 testing. Table 2 also shows the proposed revised maximum potential Baseline NOx emission rate for each boiler.

Table 2 Summary of NOx Emission Rates and Emission Factors from the 2012 Testing and the 2013-Issued Title V Permit Renewal

Boiler	October/November 2012 Test Results - Highest Result				Proposed Baseline NOx Emission Factor (1) (lb/MMBtu)	Title V Permit Current NOx RACT Emission Rate (lb/Hr)	Title V Permit Current NOx RACT Emission Rate (lb/MMBTU)
	O2%	NOx Concentration (ppmv)	NOx Emission Rate (lb/hr)	NOx Test Emission Factor (lb/MMBTU)			
1	6.66	65.6	6.7	0.10	0.15	68.08	0.92
3	7.05	84.1	10.48	0.13	0.20	80.64	0.63
5	7.40	72.6	6.67	0.12	0.18	43.66	0.59
6	1.87	86.5	9.86	0.10	0.15	50.12	0.28
7(2)	8.95	70	7.93	0.09	0.13	38.0	0.20

Note: The title V permit application was submitted before this testing campaign was initiated.

(1) The proposed Baseline Emission Factor includes a 50% safety factor above the test results.

(2) BBP Boiler No. 7 NOx CEMS Data March 2, 2013 through February 28, 2014

Low NOx Burners and Flue Gas Recirculation

On February 13, 2014, BBP received a budgetary quote from Mr. Dan Rice of Rice and Associates for the installation of a COEN burner with flue gas recirculation on each of Boilers 1, 3, 5, 6 and 7. Boiler 8a was excluded from the quote and is not included in this analysis because it is a temporary boiler not owned by BBP. When it is brought on-site, it is equipped with low-NOx burners. The budgetary quote is included in Attachment B of this letter and the equipment capital costs are summarized in Table 3. This summary only includes the capital cost of the equipment and does not include installation, demolition, operation, and maintenance costs. These other costs are addressed in the economic feasibility section below.

Table 3 Summary of Equipment Capital Costs for the Installation of Natural Gas Low NOx Burners

Equipment	Boiler 1	Boiler 3	Boiler 5	Boiler 6	Boiler 7
VariFlame Burner	$90,000	$90,000	$90,000	$100,000	$100,000
Windbox	$35,000	$35,000	$35,000	$40,000	$40,000
Fuel Trains-	$80,000	$80,000	$80,000	$100,000	$100,000
Force Draft Fans	$90,000	$90,000	$90,000	$110,000	$110,000
Total	$295,000	$295,000	$295,000	$350,000	$350,000

The COEN quote guarantees that the new natural gas burners when combined with flue gas recirculation will emit a NOx concentration no greater than 30 ppmv corrected to 3% oxygen. This NOx concentration equates to an emission factor of approximately 0.036 lb/MMBTU. Table 4 summarizes the NOx emissions rate data from the COEN quote.

Table 4 Summary of COEN VariFlame® Burner Data

Boiler No.	Fuel	Maximum Steam Rate (lb/hr x 10^3)	Design Natural Gas (NG) Heat Input (MMBtu/hr)	NOx Emission Factor (lb/MMBTU)(2)
1	Natural Gas (NG)/ Fuel Oil (FO) Backup	100	135	0.036
3	NG Primary/ FO Backup	100	135	0.036
5	NG Primary/ FO Backup	100	135	0.036
6	NG Primary/ FO Backup	150	185	0.036
7	NG Primary/ FO Backup	150	190	0.036

(1) Calculated from the COEN Variflame® Low NOx Burner with FGR Guarantee of 30 ppmv NOx @ 3% Oxygen

(2) COEN NOx Emission Factor Calculated as follows:

NOx ppmv@ 3% O2 dry (DSCF/DSCF)	*O2 Correction for Excess Air*	*Gas constant @ STD Cond*	*NO2 MW*	*Natural Gas Fd (DSCF/MMBTU)*	*NOx Emission Rate*
30 ft3 x	20.9% x	1 lb-mole x	46 lb x	8710 ft3 =	0.036 lb/MMBTU
1,000,000 ft3	(20.9% - 3.0%)	385 ft3	1 lb-mole	1 MMBTU	

Economic Feasibility of Replacing Existing Burners with COEN LNB and FGR

The economic feasibility of replacing the existing burners with new natural gas LNB equipped with FGR is summarized in Table 5. The RACT economic feasibility threshold of $2,500 per ton of NOx removed is from the Pennsylvania Department of Environmental Protection (PADEP) Regulatory Analysis Form for the proposed rule changes to 25 Pa. Code Chapters 121 and 129 for Presumptive RACT. PADEP adjusted the RACT I cost benchmarks of $1,500 per ton of NOx removed, by multiplying by the consumer price index (CPI) differential between 1990 and 2010 of 1.67 to arrive at the benchmark of $2,500 per ton of NOx emissions removed for RACT 2. They found their NOx benchmark of $2,500 to be consistent with Wisconsin's NOx cost benchmark and the Wisconsin SIP revision was approved by the EPA at 75 FR 64155 (October 19, 2010). The detailed economic analyses are included in Attachment C.

On the basis of this NOx RACT Re-evaluation, the installation of the COEN LNB with FGR is economically infeasible for the BBP, and RACT is considered to be the operation of the existing burners. Since the current NOx RACT limits for Boilers 1, 3 and 5 in the most recent issuance of BBP's Title V permit renewal are still based on combustion of coal, BBP proposes a reduction in the NOx RACT limits to the levels shown in Table 6, below. These are based on the most recent stack test results shown in Table 2, with an adjustment to allow for variability of future stack test results and the requirement for continuous compliance with the maximum potential emission rate. Microsoft Excel Spreadsheet support calculations are included on a compact disc in Attachment D.

Table 5 Estimate of RACT Economic Feasibility for Installing Low NOx Burners with FGR at Bellefield Boiler Plant

Boiler	Baseline NOx Emission Factor (lb/MMBTU)	Annual Max Potential Heat input Rate (MMBTU/Yr)	Existing Burners Annual Emission Rate (Tons/Yr)	COEN Guarantee Emission Factor (lb/MMBTU)	COEN Burners Annual Emission Rate (Tons/Yr)	Cost/ 10 years	Cost/ton NOx removed	Estimated RACT Threshold Above which Technology is Economically Infeasible Cost/Ton NOx Removed	Feasible based on Cost (Yes/No?)
1	0.15	648,240	48.6	0.036	11.8	$257,000	$6,983.14	$2,500.00	No
3	0.20	560,640	54.7	0.036	10.2	$250,000	$5,625.06	$2,500.00	No
5	0.18	648,240	58.3	0.036	11.8	$250,000	$5,373.28	$2,500.00	No
6	0.15	1,568,040	117.6	0.036	28.6	$295,000	$3,313.74	$2,500.00	No
7	0.14	411,720	27.8	0.036	7.5	$295,000	$14,541.37	$2,500.00	No
					Average	**$269,400**	**$7,167**	**$2,500.00**	**No**

Table 6 Proposed NOx RACT Limits

Boiler	Test Result (lb/MMBTU)(1)	Scaling Factor (2)	Proposed Natural Gas NOx RACT Emission Rate (lb/MMBTU)	Current Title V NOx RACT Emission Rate (lb/MMBTU)
1	0.10	1.5	0.15	0.92
3	0.13	1.5	0.20	0.63
5	0.12	1.5	0.18	0.59
6	0.10	1.5	0.15	0.28
7	0.09	1.5	0.14	0.20

(1) All test results from 2012 test campaign except Boiler No. 7, which is based on March 2013-February 2014 CEMS Data.

(2) Based on estimated 50 percent safety factor between test data and maximum potential emission rate.

Justification of ACHD's RACT Re-evaluation Requirement

As discussed in our December 24, 2013 letter to ACHD, BBP is still seeking ACHD's justification for the RACT re-evaluation. ACHD's December 6, 2013 letter mentions the U.S. Environmental Protection Agency's ("EPA) June 6, 2013 proposed rule for state implementation of the 2008 ozone national ambient air quality standards ("NAAQS"), including requirements related to RACT. EPA's proposed rule, however, is not a final rule. Because EPA's rule is not final, can you please provide the legal basis for ACHD's requirement to re-evaluate NOx for the 8-hour ozone NAAQS?

We look forward to your response.

Very truly yours,

Kevin Hiles

Kevin Hiles,
Chairman of the Supervising Committee

cc: Mr. Robert Miller
Mr. Tony Young
Mr. David Wagner

Enclosure

ATTACHMENT A

October – November, 2012

Stack Test Results

(14 pages)

BOILERS 1, 3, 5, AND 6
COMPLIANCE TEST REPORT
BELLEFIELD BOILER PLANT
PITTSBURGH, PENNSYLVANIA

Test Dates: October 16 and 17, 2012

Report Date: November 2, 2012

Prepared for:

Bellefield Boiler Plant
4400 Forbes Avenue
Pittsburgh, Pennsylvania 15213

Prepared by:

Air/Compliance Consultants, Inc.
1050 William Pitt Way
Pittsburgh, Pennsylvania 15238
412-826-3636

PA Lab Registration #02-04775

Project Number: 12-131

Air/Compliance Consultants, Inc.

CERTIFICATION STATEMENT

This statement certifies that "to the best of their knowledge," based on state and federal regulations, operating permits, plan approvals applicable to each source tested, and reasonable inquiry, the statements and information presented in the attached document are true, accurate, and complete.

BOILERS 1, 3, 5, AND 6
COMPLIANCE TEST REPORT
BELLEFIELD BOILER PLANT
PITTSBURGH, PENNSYLVANIA

Test Dates: October 16 and 17, 2012

Project Number: 12-131

for ______________________ 11-2-12

Joshua S. Varner, QSTI
Project Scientist and On-site Supervisor
Air/Compliance Consultants, Inc.

Date

______________________ 11/2/12

William J. Ondriezek, Jr., QI
Source Testing and Quality Manager
Air/Compliance Consultants, Inc.

Date

______________________ ______

Kevin D. Hiles
Bellefield Boiler Plant Supervising Committee and Responsible Official
Bellefield Boiler Plant

Date

TABLE OF CONTENTS

TABLES

APPENDICES

NATURAL GAS-FIRED BOILERS 1, 3, 5, and 6
COMPLIANCE TEST REPORT
BELLEFIELD BOILER PLANT
PITTSBURGH, PENNSYLVANIA

1 TEST RESULTS SUMMARY

Permit Number: Title V Permit No. #00-47			
Pollutant	**Average Result**	**Permit Limit**	**Compliant / Non-compliant**
Source ID: Boiler 1			
NO_x	6.65 lb/hr	68.08 lb/hr	Compliant
	0.10 lb/MMBtu	0.92 lb/MMBtu	Compliant
	29.1 tons/year*	376 tons/year	Compliant
Source ID: Boiler 3			
NO_x	10.29 lb/hr	80.64 lb/hr	Compliant
	0.13 lb/MMBtu	0.63 lb/MMBtu	Compliant
	45.0 tons/year*	242 tons/year	Compliant
Source ID: Boiler 5			
NO_x	6.59 lb/hr	43.66 lb/hr	Compliant
	0.12 lb/MMBtu	0.59 lb/MMBtu	Compliant
	28.8 tons/year*	261 tons/year	Compliant
Source ID: Boiler 6			
NO_x	9.59 lb/hr	50.12 lb/hr	Compliant
	0.10 lb/MMBtu	0.28 lb/MMBtu	Compliant
	42.0 tons/year*	191 tons/year	Compliant

*Based on 8,760 operating hours

2 INTRODUCTION

Air/Compliance Consultants, Inc. (ACCI) conducted a compliance emissions evaluation on four natural gas-fired boilers (1, 3, 5, and 6) at Bellefield Boiler Plant (Bellefield) in Pittsburgh, Pennsylvania. The purpose of the testing was to determine compliance with Allegheny County Health Department (ACHD) Article XXI requirements for biennial testing for large sources and Title V Operating Permit #00-47. The sources were tested as detailed in the July 2012 ACHD Test Protocol and the methodology detailed in the United States Environmental Protection Agency

(USEPA) Code of Federal Regulations (CFR) 40 Part 60 Appendix A. A copy of the test protocol is contained in Appendix A.

3 CONTACT INFORMATION

Company	Testing Firm
Mr. Robert Miller Bellefield Boiler Plant 4400 Forbes Avenue Pittsburgh, Pennsylvania (412) 622-3354 – Telephone (412) 622-1931 – Cell Phone millerb@carnegiemuseums.com	Mr. Joshua S. Varner, QSTI Air/Compliance Consultants, Inc. 1050 William Pitt Way Pittsburgh, Pennsylvania 15238 (412) 826-3636 – Telephone (724) 422-4177 – Cell Phone jvarner@air-comp.com

4 TEST DATES AND PERSONNEL

Testing was conducted on October 16 and 17, 2012. The following table details the contact personnel regarding this test program:

Organization	Personnel	Responsibility
Bellefield Boiler Plant	Mr. Robert Miller	Test Liaison
ACHD	Mr. Greg Poindexter Mr. Najeeb Basher	Agency Representatives
ACCI	Mr. Joshua S. Varner, QSTI	Instrument Operator
	Mr. Justin G. Bryan	Equipment Handler

5 PROCESS DESCRIPTION and DATA

5.1 Process Description

Bellefield operates six (6) boilers to provide steam heat to buildings of its non-profit owners, including the University of Pittsburgh, Carnegie Mellon University, The Carnegie Museum, University of Pittsburgh Medical Center (UPMC), and the City of Pittsburgh. Four boilers (Boilers 1, 3, 5, and 6) were tested as part of this compliance testing program. All boilers are fired on natural gas. Boiler 1 (74 million British thermal units per hour [MMBtu/hr]), Boiler 3 (128 MMBtu/hr), and Boiler 5 (74 MMBtu/hr) have a maximum steam flow rate of 100,000 pounds per hour (lb/hr)[1]. Boiler 6 is a natural gas-fired boiler rated at 179 MMBtu/hr with flue gas recirculation.

5.2 Process Data

The production and emissions control equipment data were recorded by Bellefield's Data Acquisition System (DAS) and are located in Appendix B as well as on the emission summary table. Data was recorded every minute during testing.

6 TEST PROCEDURES

6.1 Fieldwork

All source testing was conducted in accordance with the July 2012 Test Protocol and CFR Title 40, Part 60, Appendix A, USEPA Methods 3A, 7E, 19, and 205. All field data sheets for the test procedures described below are included in Appendix C.

6.2 Carbon Dioxide and Oxygen Determination – USEPA Method 3A

The principles of USEPA Method 3A, *Gas Analysis for the Determination of Dry Molecular Weight, Instrumental Analyzer Procedure,* were utilized for the determination of oxygen (O_2) and carbon dioxide (CO_2). Percent O_2 and CO_2 were determined in accordance with USEPA Method 3A. A paramagnetic analyzer was used to continuously measure O_2 concentrations and a non-dispersive infrared (NDIR) analyzer was used to continuously measure CO_2 concentrations. An extractive gas-conditioning system was used to convey the sample to the gas analyzers. Nitrogen (N_2) concentration was determined by the difference.

6.3 Oxides of Nitrogen Emissions – USEPA Method 7E

All principles of USEPA Method 7E, *Determination of Nitrogen Oxides Emissions from Stationary Sources (Instrumental Analyzer Procedure)* that were outlined in the September Protocol, were used for this test program. A gas sample was continuously extracted from the exhaust stack from a single point for this test program. Three 60-minute sampling runs were performed on each exhaust stack.

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[1] The maximum capacity stated in the permit for Boilers 1 and 5 is 125 MMBtu/hr and 134 MMBtu/hr, respectively, because these Boilers were coal fired. However, Bellefield voluntarily converted those Boilers to natural gas firing in 2009, and the maximum capacity of the gas burners on them is 74 MMBtu/hr.

Analyzer calibrations were manually recorded on the run bias sheets and are provided with the field data sheets in Appendix C. Analyzer interference and converter efficiency tests all followed Section 8 of USEPA Method 7E and results are located in Appendix D.

6.4 Determination of Emission Factors – USEPA Method 19

Emission factors were determined in accordance with USEPA Method 19 using the standard F-factor 8,710 dry standard cubic feet (DSCF) per MMBtu for Natural Gas.

6.5 Verification of Gas Dilution System – USEPA Method 205

USEPA Method 205, *Verification of Gas Dilution Systems for Field Instrument Calibrations,* utilizing USEPA Protocol gases and an Environics Model 4040 Computerized Gas Dilution System, were used for several analyzer calibration values. USEPA Method 205 results, depicting the specific unit and mass flow controller used along with the unit calibration data, are included in Appendix D.

6.6 Calibrations

The following field equipment calibrations are also contained in Appendix D:

- Analyzer Interference Checks
- Gas Dilution System Calibration
- Calibration Gas Certificates
- Qualified Source Testing Individual (QSTI) Certification

6.7 Calculations

Emission calculations were completed using a computer spreadsheet format. The results of each pertinent parameter are detailed on the spreadsheet for each sampling run and provided in Appendix C. A sample calculation for one test run is also provided in Appendix E.

7 TESTING SUMMARY

The results of the testing performed are presented in Tables 1, 2, 3 and 4 and the nomenclature is included as Table 5.

8 CONCLUSION

A compliance test program has been conducted for Bellefield Boiler Plant on the Natural Gas-fired Boilers (1, 3, 5, and 6) at their Pittsburgh, Pennsylvania plant. Test results represent data that is considered to be representative of the emission rates at the prevailing operating conditions.

To the best of ACCI's knowledge, this source test report has been checked for completeness and the results contained herein are accurate, error-free, and representative of the actual emissions measured during testing.

Tables

Table 1. CEM Test Results, Boiler #1 Natural Gas Firing
Bellefield Boiler Plant, Pittsburgh, Pennsylvania

Test Data		Run 1	Run 2	Run 3	Average	
Date		10/17/12	10/17/12	10/17/12		
Start Time		11:40 AM	12:52 PM	2:02 PM		
End Time		12:40 PM	1:52 PM	3:02 PM		
Carbon Dioxide (CO_2)	(dry volume %)	8.34	8.35	8.29	8.33	
Oxygen (O_2)	(dry volume %)	6.76	6.66	6.71	6.71	
Boiler Operation						
Fd @ 68 F and 760 mm Hg (NA if NA)	(dscf/MMBtu)	8,710	8,710	8,710	8,710	
Fuel Flow Rate	(SCF/hr)	64,500	64,300	64,200	64,333	
Fuel Btu Content	(Btu/SCF)	1,040	1,040	1,040	1,040	
Heat Input Based on Fuel Flow Rates	(MMBtu/hr)	67.08	66.87	66.77	66.91	
Steam Flow	(lb/hr)	49,000	49,600	49,600	49,400	
Fuel Factor (Fo)		1.695	1.705	1.712	1.704	
Results						**Limits**
Nitrogen Oxides (NO_x) as NO_2						
Emission Concentration	(ppm_{dv})	64.5	65.6	64.6	64.9	
Emission Rate[1]	(lb/hr)	6.65	6.70	6.61	6.65	68.08
Emission Factor (Eq. 19-1)	(lb/MMBtu)	0.099	0.100	0.099	0.099	0.920
Emission Rate[2]	(tons/yr)	29.1	29.3	28.9	29.1	376.0

CEM results have been bias calibration corrected.

[1]Based on heat input

[2]Based on 8,760 operating hours

ATTACHMENT B
Rice Associates COEN LNB/FGR
Budgetary Quote

JOHN ZINK HAMWORTHY COMBUSTION

HAMWORTHY PEABODY COEN TODD

Date: February 12, 2014

Re: **Bellefield Boiler Plant**
Boilers #1, #3, #5, #6 and #7 Retrofit

Coen Reference #: 201402-41806A#

Attention: Mr. Robert Miller

In response to your request, the Coen Division of John Zink Company, LLC ("Coen") is pleased to submit the following budgetary quote for the supply of Low NOx burners and combustion equipment to reduce emissions in all five (5) boilers at Bellefield Boiler Plant. We appreciate the opportunity to provide you with these pricing and we hope it helps you to continue your feasibility and estimating evaluation.

Boiler Information

	Boiler #1	Boiler #3	Boiler #5	Boiler #6	Boiler #7
Boiler Manufacturer	Unknown	Unknown	Unknown	Zurn	Volcano
Boiler Type	Stoker	Stoker	Stoker	O type	D type
Burners per Boiler	1	1	1	1	1
Burner Location	Side-wall	Side-wall	Side-wall	Front-wall	Front-wall
Steam Flow (PPH)	100,000	100,000	100,000	150,000	150,000
Steam Pressure (psi)	175	175	175	175	175
Steam Temperature	Sat.	Sat.	Sat.	Sat.	Sat.
Furnace Depth	20.0'	22.33'	29.0'	31.50'	30.50'
Furnace Width	18.0'	18.90'	20.0'	8.66'	6.75'
Furnace Height	16.25'	16.25'	22.0'	6.41'	12.0'
Furnace Pressure (wc)	-0.2"	-0.2"	-0.2"	1.0"	1.0"
Economizer Used	No	No	No	Yes	No
Preheater Used	No	No	No	No	No
Combustion Air Temp (°F)	80	80	80	80	80
Flue Gases Temp. (°F)	600	600	600	350	600
Location	Indoors				
Plant Elevation (FASL)	500				
Area Classification	Non-Hazardous				
NEMA Class Rating	Nema 4				
Code Requirements	NFPA 85				
Piping Requirements	Coen Standard				
Painting Requirements	Coen Standard				

John Zink Company LLC • 11920 East Apache Street • Tulsa, Oklahoma 74116 • United States
T: +1.918.234.1800 • F: +1.918.234.2700

Coen's Approach

Coen's proposed approach consist on replacing the existing burners currently installed at each boiler and replace them with new low NOx Variflame™ burners. New burners will meet NOx emissions as low as 30 ppm when firing natural gas in combination with flue gas recirculation (FGR) according with the following operating parameters.

	Boiler #1	Boiler #3	Boiler #5	Boiler #6	Boiler #7
Burner Heat Release (MMBtu/Hr) Gas / Oil	135 / 126	135 / 126	135 / 126	185 / 175	190 / 183
Main Fuel(s)	Nat. Gas	Nat. Gas	Nat. Gas	Nat. Gas	Nat. Gas
Back-up Fuel (s)	No. 2 Oil	No. 2 Oil	No. 2 Oil	No. 2 Oil	No. 2 Oil
Ignition Fuel	Nat. Gas	Nat. Gas	Nat. Gas	Nat. Gas	Nat. Gas
Estimated Excess Air	15%	15%	15%	15%	15%
FGR rate	16%	16%	16%	26%	24%
Gas Pressure @ Burner	10 psi	10 psi	10 psi	10 psi	10 psi
Oil Pressure @ Burner	150 psi	150 psi	150 psi	150 psi	150 psi
Atomizing Medium	Steam	Steam	Steam	Steam	Steam
Comb. Air Flow (lb/hr)	132,650	132,650	132,650	198,200	198,200
Burner Draft Loss	9.0" wc	7.0" wc	7.0" wc	8.0" wc	8.0" wc
Estimated NOx, Gas	**30 ppm**	**30 ppm**	**30 ppm**	**30 ppm**	**30 ppm**
Estimated NOx, Oil	**150 ppm**	**150 ppm**	**150 ppm**	**150 ppm**	**150 ppm**
Estimated CO, Gas	**100 ppm**	**100 ppm**	**100 ppm**	**100 ppm**	**100 ppm**
Estimated CO, Oil	**200 ppm**	**200 ppm**	**200 ppm**	**200 ppm**	**200 ppm**

Scope

Proposed Base work scope on a *per boiler basis* consists of the following:

- Design Engineering Services and Project Management
- Airflow Modeling (CFD) – Existing windbox
- Dual fired, Variflame™ burner complete with:
  - Gas burner assembly
  - Oil gun assembly
  - Gas-electric igniter
  - Flame scanners
  - Burner throat former template
  - Installation mounting plate

Optional scope:

- New Burner Windbox (if required)
- New Fuel Trains as per NFPA 85 for main gas, pilot gas, No. 2 oil and atomizing steam
- New Forded Draft Fan assembly to supply the required amount of combustion air and induced FGR to achieve burner capacity and emissions, complete with:
  - FD fan centrifugal type complete with inlet vane damper, flanged outlet and TEFC motor
  - Air/FGR mixing box with fresh air inlet damper
  - Pneumatic actuators with I/P positioner for driving the fan IVC and fresh air dampers
  - Flue gas recirculation manual damper (ship loose)

* *All fan components will be shipped direct from the manufacturer for field installation by others.*

Budget Pricing

	Boiler #1	Boiler #3	Boiler #5	Boiler #6	Boiler #7
Base Scope. Variflame™ Burner	$90,000	$90,000	$90,000	$100,000	$100,000
Optional Windbox	$35,000	$35,000	$35,000	$40,000	$40,000
Optional Fuel Trains	$80,000	$80,000	$80,000	$100,000	$100,000
Optional FD Fan	$90,000	$90,000	$90,000	$110,000	$110,000

This is a budgetary proposal and is intended only as an estimate to facilitate your planning processes and does not constitute a commitment or offer to sell goods or services at the prices and terms referenced herein. Any firm offer or binding quotation will be the subject of a formal proposal at a future date.

General Notes

- *Base scope assumes the existing windboxes are in good shape and adequate to be reused with the new proposed burners. This has to be confirmed on a later date.*
- *Base scope assumes the existing FD and/or ID Fans are in good working condition and adequate capacity to operate with the new proposed burners. To be confirmed later.*
- *Burner throat refractory and retaining tub assembly is not included in Coen scope.*
- *Boiler front-wall modifications (if required) to install the new burners are by others.*
- *Burner operating parameters and emission predictions are estimated only. Customer shall confirm above boiler's information and provide furnace sectional drawings.*
- *Customer shall provide existing burner, windbox and throat opening drawings on a later date.*
- *All emissions are referenced to 3% dry stack O2.*
- *BMS and Controls modifications and integration into existing DCS is by others.*
- *Flue gas recirculation ducting is by others.*
- *Erection and field installation of all the equipment supplied is by others.*

This proposal document is confidential and intended solely for the use of the individual or entity to which it is addressed. If you have received this proposal in error, please contact the sender and destroy all copies of the original message.

We thank you for the opportunity to present this proposal and look forward to continue working with you on this project.

Coen's contact for all technical and administrative inquiries is:

German Lopez
Application Engineer - Coen Division,
John Zink Company, LLC.
951 Mariners Island Blvd. Ste. 410
San Mateo, CA 94404
TEL: (650) 522-2137
E-mail: glopez@coen.com

I spoke to Rob Dull at Cannon Boiler to get a rough estimate for installation. It was a verbal conversation and I did not reveal Bellefield is the customer. Rob advised a budget price for removing and installing the **burner only** would be around $150,000.00. The price does not include wiring to the BMS, ducting or new fan installation. This is an estimate only and he expects the actual price to be lower.

For both Coen and Cannon to provide firm pricing, they will have to get more detailed information regarding the existing boilers and burners. I hope you find this information helpful in working with Allegheny County. Please do not hesitate to contact us if you have any questions or if we can provide additional information.

Sincerely,
Dan Rice
Rice Associates
Phone: (412) 487-5530
Cell: (412) 952-3193

From: Lopez, German [mailto:german.lopez@coen.com]
Sent: Wednesday, February 12, 2014 3:24 PM
To: riceassociates@earthlink.net
Cc: 'John Pistella'
Subject: RE: Bellefield Boiler Plant

Dan,

Here is our budgetary quote for Low NOx burners to Bellefield as agreed. Please take a look and let me know if you have any comment or question.

If no, please feel free to submit it to the customer. Once submitted I would like you to follow up and get customer feedback when they heard back from the county.

Thanks and best regards,

German Lopez | Application Engineer
John Zink Company LLC

From: Dan Rice [mailto:riceassociates@earthlink.net]
Sent: Friday, January 31, 2014 11:29 AM
To: Lopez, German
Cc: 'John Pistella'
Subject: Bellefield Boiler Plant

German:

Earlier this week I spoke to you regarding the subject retrofit opportunity. The Bellefield Boiler Plant is a central steam plant that provides steam to the University of Pittsburgh, Carnegie Mellon University and several other

ATTACHMENT C

Detailed Economic Analysis

Purchase, installation, Operation and Maintenance Costs

for a COEN VariFlame® LNB/FGR

Table 1 - Boiler 1 Exhaust -
Low NOx Burner for NOx Control - Capital and O&M Costs

CAPITAL COSTS		
Direct Costs		
Purchased Equipment Costs		
Low NOx Burner	$90,000	
Windbox	$35,000	
Fuel Trains	$80,000	
Forced Draft Fan	$90,000	
Sales Tax and Freight	$24,000	
1. Purchased Equipment Cost = A	$319,000	
Direct Installation Costs		
Handling and Erection 0.40xA	$128,000	
Electrical 0.10xA	$32,000	
Instrumentation & Controls 0.12xA	$38,000	
Piping & Ductwork 0.20xA	$64,000	
Painting & Insulation 0.10xA	$32,000	
2. Total Direct Installation Cost	$294,000	
Indirect Costs		
Engineering 0.20xA	Included in Equipment	
Construction and Field Expenses 0.20xA	$64,000	
Contractor Fees 0.10xA	$32,000	
Start-Up, Performance Test & Contingencies 0.05*A	$16,000	
3. Total Indirect Cost	$112,000	
TOTAL CAPITAL INVESTMENT (1+2+3)	$725,000	
TOTAL ANNUALIZED CAPITAL COST (i =10%, 10 yrs, crf = 0.16275)		$118,000
ANNUAL O&M COSTS		
Operating Labor		
(2 hr/day x 365 day/yr x $25/hr x 1.35 for fringe benefits)	$25,000	
Supervisory Labor		
(15% of operating labor)	$4,000	
Maintenance Labor		
(2 hr/day x 365 days/yr x $27/hr x 1.35 f.b.)	$27,000	
Maintenance Materials		
(100% of maintenance labor)	$27,000	
Power - Additional FD Fan Power cost		
(0.000157 x 30025 acfm x 9 inches wc x 1/0.65 = 65 hp)		
(65 hp x 0.75 kw/hp x 8760 hr/yr x $0.08/kwhr)	$34,000	
Administration & Insurance		
(0.03 x Total Capital Investment)	$22,000	
TOTAL ANNUAL O&M COST		$139,000
TOTAL ANNUAL COST		$257,000
Tons of NOx Removed per Year		**36.80**
TOTAL COST PER TON OF NOx REMOVED		**$7,000**

(0.000157 x 30025 acfm x 9 inches wc x 1/0.65 = 65 hp)
(65 hp x 0.75 kw/hp x 8760 hr/yr x $0.08/kwhr)

Table 2 - Boiler 3 Exhaust -
Low NOx Burner for NOx Control - Capital and O&M Costs

CAPITAL COSTS		
Direct Costs		
Purchased Equipment Costs		
Low NOx Burner	$90,000	
Windbox	$35,000	
Fuel Trains	$80,000	
Forced Draft Fan	$90,000	
Sales Tax and Freight	$24,000	
1. Purchased Equipment Cost = A	$319,000	
Direct Installation Costs		
Handling and Erection 0.40xA	$128,000	
Electrical 0.10xA	$32,000	
Instrumentation & Controls 0.12xA	$38,000	
Piping & Ductwork 0.20xA	$64,000	
Painting & Insulation 0.10xA	$32,000	
2. Total Direct Installation Cost	$294,000	
Indirect Costs		
Engineering 0.20xA	Included in Equipment	
Construction and Field Expenses 0.20xA	$64,000	
Contractor Fees 0.10xA	$32,000	
Start-Up, Performance Test & Contingencies 0.05*A	$16,000	
3. Total Indirect Cost	$112,000	
TOTAL CAPITAL INVESTMENT (1+2+3)	$725,000	
TOTAL ANNUALIZED CAPITAL COST (i =10%, 10 yrs, crf = 0.16275)		$118,000
ANNUAL O&M COSTS		
Operating Labor		
(2 hr/day x 365 day/yr x $25/hr x 1.35 for fringe benefits)	$25,000	
Supervisory Labor		
(15% of operating labor)	$4,000	
Maintenance Labor		
(2 hr/day x 365 days/yr x $27/hr x 1.35 f.b.)	$27,000	
Maintenance Materials		
(100% of maintenance labor)	$27,000	
Power - Additional FD Fan Power cost		
(0.000157 x 30025 acfm x 7 inches wc x 1/0.65 = 51 hp)		
(51 hp x 0.75 kw/hp x 8760 hr/yr x $0.08/kwhr)	$27,000	
Administration & Insurance		
(0.03 x Total Capital Investment)	$22,000	
TOTAL ANNUAL O&M COST		$132,000
TOTAL ANNUAL COST		$250,000
Tons of NOx Removed per Year		**44.44**
TOTAL COST PER TON OF NOx REMOVED		**$5,600**

(0.000157 x 30025 acfm x 7 inches wc x 1/0.65 = 51 hp)
(51 hp x 0.75 kw/hp x 8760 hr/yr x $0.08/kwhr)

Table 3 - Boiler 5 Exhaust -
Low NOx Burner for NOx Control - Capital and O&M Costs

CAPITAL COSTS		
Direct Costs		
Purchased Equipment Costs		
Low NOx Burner	$90,000	
Windbox	$35,000	
Fuel Trains	$80,000	
Forced Draft Fan	$90,000	
Sales Tax and Freight	$24,000	
1. Purchased Equipment Cost = A	$319,000	
Direct Installation Costs		
Handling and Erection 0.40xA	$128,000	
Electrical 0.10xA	$32,000	
Instrumentation & Controls 0.12xA	$38,000	
Piping & Ductwork 0.20xA	$64,000	
Painting & Insulation 0.10xA	$32,000	
2. Total Direct Installation Cost	$294,000	
Indirect Costs		
Engineering 0.20xA	Included in Equipment	
Construction and Field Expenses 0.20xA	$64,000	
Contractor Fees 0.10xA	$32,000	
Start-Up, Performance Test & Contingencies 0.05*A	$16,000	
3. Total Indirect Cost	$112,000	
TOTAL CAPITAL INVESTMENT (1+2+3)	$725,000	
TOTAL ANNUALIZED CAPITAL COST (i =10%, 10 yrs, crf = 0.16275)		$118,000
ANNUAL O&M COSTS		
Operating Labor		
(2 hr/day x 365 day/yr x $25/hr x 1.35 for fringe benefits)	$25,000	
Supervisory Labor		
(15% of operating labor)	$4,000	
Maintenance Labor		
(2 hr/day x 365 days/yr x $27/hr x 1.35 f.b.)	$27,000	
Maintenance Materials		
(100% of maintenance labor)	$27,000	
Power - Additional FD Fan Power cost		
(0.000157 x 30025 acfm x 7 inches wc x 1/0.65 = 51 hp)		
(51 hp x 0.75 kw/hp x 8760 hr/yr x $0.08/kwhr)	$27,000	
Administration & Insurance		
(0.03 x Total Capital Investment)	$22,000	
TOTAL ANNUAL O&M COST		$132,000
TOTAL ANNUAL COST		$250,000
Tons of NOx Removed per Year		**46.53**
TOTAL COST PER TON OF NOx REMOVED		**$5,400**

(0.000157 x 30025 acfm x 7 inches wc x 1/0.65 = 51 hp)
(51 hp x 0.75 kw/hp x 8760 hr/yr x $0.08/kwhr)

Table 4 - Boiler 6 Exhaust -
Low NOx Burner for NOx Control - Capital and O&M Costs

CAPITAL COSTS		
Direct Costs		
Purchased Equipment Costs		
Low NOx Burner	$100,000	
Windbox	$40,000	
Fuel Trains	$100,000	
Forced Draft Fan	$110,000	
Sales Tax and Freight	$28,000	
1. Purchased Equipment Cost = A	$378,000	
Direct Installation Costs		
Handling and Erection 0.40xA	$151,000	
Electrical 0.10xA	$38,000	
Instrumentation & Controls 0.12xA	$45,000	
Piping & Ductwork 0.20xA	$76,000	
Painting & Insulation 0.10xA	$38,000	
2. Total Direct Installation Cost	$348,000	
Indirect Costs		
Engineering 0.20xA	Included in Equipment	
Construction and Field Expenses 0.20xA	$76,000	
Contractor Fees 0.10xA	$38,000	
Start-Up, Performance Test & Contingencies 0.05*A	$19,000	
3. Total Indirect Cost	$133,000	
TOTAL CAPITAL INVESTMENT (1+2+3)	$859,000	
TOTAL ANNUALIZED CAPITAL COST (i =10%, 10 yrs, crf = 0.16275)		$140,000
ANNUAL O&M COSTS		
Operating Labor		
(2 hr/day x 365 day/yr x $25/hr x 1.35 for fringe benefits)	$25,000	
Supervisory Labor		
(15% of operating labor)	$4,000	
Maintenance Labor		
(2 hr/day x 365 days/yr x $27/hr x 1.35 f.b.)	$27,000	
Maintenance Materials		
(100% of maintenance labor)	$27,000	
Power - Additional FD Fan Power cost		
(0.000157 x 44862 acfm x 8 inches wc x 1/0.65 = 87 hp)		
(87 hp x 0.75 kw/hp x 8760 hr/yr x $0.08/kwhr)	$46,000	
Administration & Insurance		
(0.03 x Total Capital Investment)	$26,000	
TOTAL ANNUAL O&M COST		$155,000
TOTAL ANNUAL COST		$295,000
Tons of NOx Removed per Year		**89.02**
TOTAL COST PER TON OF NOx REMOVED		**$3,300**

(0.000157 x 44862 acfm x 8 inches wc x 1/0.65 = 87 hp)
(87 hp x 0.75 kw/hp x 8760 hr/yr x $0.08/kwhr)

Table 5 - Boiler 7 Exhaust -
Low NOx Burner for NOx Control - Capital and O&M Costs

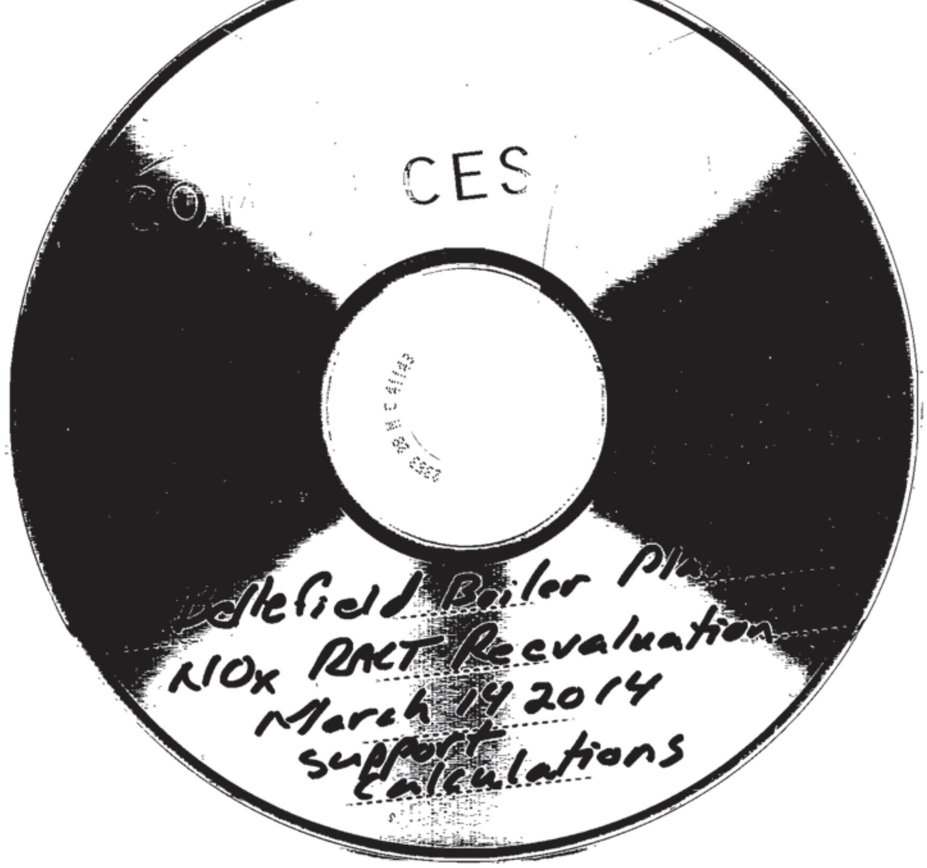
CAPITAL COSTS		
Direct Costs		
Purchased Equipment Costs		
Low NOx Burner	$100,000	
Windbox	$40,000	
Fuel Trains	$100,000	
Forced Draft Fan	$110,000	
Sales Tax and Freight	$28,000	
1. Purchased Equipment Cost = A	$378,000	
Direct Installation Costs		
Handling and Erection 0.40xA	$151,000	
Electrical 0.10xA	$38,000	
Instrumentation & Controls 0.12xA	$45,000	
Piping & Ductwork 0.20xA	$76,000	
Painting & Insulation 0.10xA	$38,000	
2. Total Direct Installation Cost	$348,000	
Indirect Costs		
Engineering 0.20xA	Included in Equipment	
Construction and Field Expenses 0.20xA	$76,000	
Contractor Fees 0.10xA	$38,000	
Start-Up, Performance Test & Contingencies 0.05*A	$19,000	
3. Total Indirect Cost	$133,000	
TOTAL CAPITAL INVESTMENT (1+2+3)	$859,000	
TOTAL ANNUALIZED CAPITAL COST (i =10%, 10 yrs, crf = 0.16275)		$140,000
ANNUAL O&M COSTS		
Operating Labor		
(2 hr/day x 365 day/yr x $25/hr x 1.35 for fringe benefits)	$25,000	
Supervisory Labor		
(15% of operating labor)	$4,000	
Maintenance Labor		
(2 hr/day x 365 days/yr x $27/hr x 1.35 f.b.)	$27,000	
Maintenance Materials		
(100% of maintenance labor)	$27,000	
Power - Additional FD Fan Power cost		
(0.000157 x 44862 acfm x 8 inches wc x 1/0.65 = 87 hp)		
(87 hp x 0.75 kw/hp x 8760 hr/yr x $0.08/kwhr)	$46,000	
Administration & Insurance		
(0.03 x Total Capital Investment)	$26,000	
TOTAL ANNUAL O&M COST		$155,000
TOTAL ANNUAL COST		$295,000
Tons of NOx Removed per Year		**20.29**
TOTAL COST PER TON OF NOx REMOVED		**$14,500**

(0.000157 x 44862 acfm x 8 inches wc x 1/0.65 = 87 hp)
(87 hp x 0.75 kw/hp x 8760 hr/yr x $0.08/kwhr)

ATTACHMENT D

Electronic Backup Calculations

(Microsoft Excel on Compact Disc)


CES
Bellefield Boiler Pl
NOx RACT Reevaluation
March 14 2014
support calculations

ALLEGHENY COUNTY HEALTH DEPARTMENT

Bellefield Boiler Plant 4400 Forbes Avenue Pittsburgh, PA 15213-4080 Allegheny County	))	**ENFORCEMENT ORDER** **NO. 248**

NOW, this 19th day of December, 1996,

WHEREAS, the Allegheny County Health Department, (hereafter referred to as "Department"), has determined that the Bellefield Boiler Plant (hereafter referred to as "Bellefield"), 4400 Forbes Avenue, Pittsburgh, Allegheny County, PA 15213-4080, as the operator of a steam generation facility at 4400 Forbes Avenue, Pittsburgh, Allegheny County, PA 15213-4080 (hereafter referred to as "the facility"), is a major stationary source of "oxides of nitrogen" emissions (hereafter referred to as "NO_x") as defined in Section 2101.20 of Article XXI, Rules and Regulations of the Allegheny County Health Department, Air Pollution Control (hereafter referred to as "Article XXI"), and

WHEREAS, the Department has determined that Section 2105.06.a. of Article XXI, entitled "Major Sources of NO_x & VOCs" is applicable to Bellefield's operations by virtue of Bellefields's emissions of NO_x; and

WHEREAS, Bellefield has timely submitted to the Department all documents required by Section 2105.06.b of Article XXI (hereafter referred to as "the proposal"); and

WHEREAS, the Department has determined, after a review of the submitted proposal, the proposal to be complete; and

WHEREAS, the Department has further determined, after review of the submitted proposal, that it constitutes Reasonably Available Control Technology (hereafter referred to as "RACT") for control of NO_x emissions from the facility; and

WHEREAS, the Department requires NO_x Lbs/MMBTU emission limitations on each boiler at the facility as a component of NO_x RACT for the facility; and

WHEREAS, pursuant to Section 2109.03 of Article XXI, the Director of the Allegheny County Health Department or his designated representative may issue such orders as are necessary to aid in the enforcement of the provisions of Article XXI, notwithstanding the absence of any violation of any provision of Article XXI and of any condition causing, contributing to, or creating danger of air pollution;

NOW, THEREFORE, this day first written above, the Department, pursuant of Section 2109.03 of Article XXI, hereby issues this Enforcement Order No. 248:

I. ORDER

1.1 At no time shall Bellefield allow emissions of NO_x from boilers one (1) through seven (7) at this facility to exceed the following NO_x emission limitations:

NO_x Emissions:

Boiler Number	Lbs/MMBTU	Tons/Year
1	0.92	376
2	0.47	258
3	0.63	242
4	0.47	241
5	0.59	261
6	0.28	191
7	0.20	65

1.2. Bellefield shall not allow the annual average heat input to the natural gas burner in Boiler No. 3, to exceed 64 MMBTU/Hr or 560,640 MMBTU

/Yr, based on a natural gas heat content of 1,028 BTU/Ft^3. Bellefield shall determine compliance with this condition by maintaining records of natural gas use for the burner.

1.3. Bellefield shall not, at any time, operate boilers one (1) through seven (7) unless the subject boilers are properly operated and maintained according to good engineering and air pollution control practices.

1.4. Bellefield shall perform NO_x emission testing on boiler number(s) one (1) through six (6) every five years in order to demonstrate compliance with the NO_x emission limitations of paragraph 1.1 above. Such testing shall be conducted in accordance with any applicable U.S. EPA approved test methods and Section 2108.02 of Article XXI. Compliance with the above referenced Lbs/MMBTU NO_x standards shall be determined by an average of three one-hour stack tests.

1.5. Bellefield shall not operate boiler number seven (7) unless a NO_x continuous emission monitoring system (CEM) is at all times in place on the subject boiler and properly operated and maintained according to 40 CFR, Part 60, Subpart Db.

1.6. Records shall be kept by the facility to demonstrate compliance with the requirements of Section 2105.06 of Article XXI and this Order. Such records shall provide sufficient data and calculations to clearly demonstrate that all requirements of section 2105.06 of article XXI and this Order are met.

1.7. Data and information required to determine compliance shall be recorded and maintained by the facility in a time frame consistent with the averaging period of the requirements. Such records shall include, but not be limited to the following:

A. Type and amount of fuel usage per boiler, (Tons/day and/or MMSCF/day);

B. Steam load per boiler, (lbs/day); and

C. Operating hours per boiler, (hours/day and days/year).

D. All records of maintenance activities, inspections calibrations and/or replacement of fuel-burning equipment--(e. g. replacement of burners, adjustments of flame patterns and/or air-to-fuel ratios).

E. All records and reports required by 40 CFR, Part 60, Subpart Db, for boiler number seven (7).

1.8. Bellefield shall retain records required by both Section 2105.06 of Article XXI and this Order for the facility for at least two (2) years and shall make the same available to the Department upon request.

1.9. The contents of this Order shall be submitted to the U.S. Environmental Protection Agency as a revision to the Commonwealth of Pennsylvania's State Implementation Plan.

1.10. Failure to comply with any portion of this Order within the times specified herein, is a violation of Article XXI giving rise to the remedies provided by Section 2109.02 of Article XXI, that may subject Bellefield to civil proceedings, including injunctive relief, by the Department.

1.11. This Order does not, in any way, preclude, limit or otherwise affect any other remedies available to the Department for violations of this Order or of Article XXI, including, but not limited to, actions to require the installation of additional pollution control equipment and the implementation of additional corrective operating practices.

1.12. This Order shall be enforceable upon issuance. If Bellefield is aggrieved by all or any part of this Order, Bellefield has the right to file a Notice of Appeal within ten (10) days of service in accordance with Article XXI. This Order shall become final ten (10) days after service if no appeal has been perfected within that period. Appeal of this Order shall not act as a stay unless so ordered by the Director of the Department.

ALLEGHENY COUNTY HEALTH DEPARTMENT

By: B W Dixon 10/19/96

Bruce W. Dixon, M.D., Director
Allegheny County Health Department

and By: Thomas J. Puzniak

Thomas J. Puzniak, Manager Engineering
Air Quality Program

ALLEGHENY COUNTY HEALTH DEPARTMENT

AIR QUALITY PROGRAM
301 39th Street, Bldg. #7
Pittsburgh, PA 15201-1811

Reasonable Available Control Technology INSTALLATION PERMIT

Issued To:	**Bellefield Boiler Plant** **654 South Neville Street** **Pittsburgh, PA 15213-4080**	**ACHD Permit#:**	**0047-I003**
		Date of Issuance:	April 14, 2020
		Expiration Date:	(See Section III.12)

Issued By: Digitally signed by JoAnn Truchan, PE Date: 2020.04.15 15:45:22 -04'00'
JoAnn Truchan, P.E.
Section Chief, Engineering

Prepared By: Hafeez Ajenifuja Digitally signed by Hafeez Ajenifuja Date: 2020.04.15 16:10:03 -04'00'
Hafeez Ajenifuja
Air Quality Engineer

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TABLE OF CONTENTS

AMENDMENTS:

DATE	SECTION(S)

I. CONTACT INFORMATION

Facility Location:	**Bellefield Boiler Plant** 654 South Neville Street Pittsburgh, PA 15213-4080
Permittee/Owner:	**Supervising Committee of the** **Bellefield Boiler Plant** 4400 Forbes Avenue Pittsburgh, PA 15213-4080
Permittee/Operator: **(if not Owner)**	Same As Owner
Responsible Official:	**Kevin D. Hiles**
Title:	Chairman
Company:	Supervising Committee of the Bellefield Boiler Plant
Address:	4400 Forbes Avenue Pittsburgh, PA 15213-4080
Telephone Number:	412-622-3351
Fax Number:	412-622-3388
Facility Contact:	**Anthony Young**
Title:	Chairman, Operating Committee
Telephone Number:	412-578-2495
Fax Number:	412-622-3388
E-mail Address:	**youngt@carnegiemuseums.org**

AGENCY ADDRESSES:

ACHD Contact:	**Chief Engineer** **Allegheny County Health Department** Air Quality Program 301 39th Street, Building #7 Pittsburgh, PA 15201-1811
EPA Contact:	**Enforcement Programs Section (3AP12)** **USEPA Region III** 1650 Arch Street Philadelphia, PA 19103-2029

II. FACILITY DESCRIPTION

FACILITY DESCRIPTION

The Bellefield Boiler Plant is a captive steam generation facility located on South Neville Street in the Oakland section of Pittsburgh, PA and it supplies steam for heating to institutional sites in that area. The plant is composed of six (6) boilers emitting from one stack. All of the boilers fire natural gas as their primary fuel. The boilers have the capacity to fire no. 2 fuel oil with sulfur content of 0.05% (500 ppm) at times of emergency, including natural gas curtailment and natural gas supply interruption, and during maintenance, periodic testing and startups with the exception of boilers 1, 5 and 8a, which do not have the capability to fire fuel oil. Boilers 3, 6 and 7 emergency fuel oil usage will be based on an annual capacity factor of 4.91%. The facility also has two (2) oil fired emergency generators rated at 771 hp (5.4 MMbtu/hr) each.

The facility is a major source of nitrogen oxides (NO_X) and carbon monoxide emissions (CO), a minor source of particulate matter (PM), particulate matter < 10 microns in diameter. (PM_{10}), sulfur oxide (SO_X), volatile organic compounds (VOCs) and hazardous air pollutants (HAPs) as defined in section 2101.20 of Article XXI.

INSTALLATION DESCRIPTION

This installation permit is for inclusion of physical and operational conditions for subject facility pursuant to Reasonable Available Control Technology (RACT II) in section 2105.06 of Article XXI. There are no new units being added to the facility as part of this permitting action.

The emission units regulated by this permit are summarized in Table II-1:

TABLE II-1: Emission Unit Identification

I.D.	SOURCE DESCRIPTION	CONTROL DEVICE(S)	MAXIMUM CAPACITY	FUEL/RAW MATERIAL	STACK I.D.
B001	Boiler 1	None	74 MMBtu/Hr	Natural Gas	S002
B003	Boiler 3	None	119 (fuel oil); 128 (natural gas) MMBtu/Hr	Natural Gas/ No. 2 Fuel Oil	S002
B005	Boiler 5	None	74 MMBtu/Hr	Natural Gas	S002
B006	Boiler 6, Package Boiler	Flue Gas Recirculation	179 MMBtu/Hr	Natural Gas/ No. 2 Fuel Oil	S002
B007	Boiler 7, Package Boiler	Low NO_X Burners	188 MMBtu/Hr	Natural Gas/ No. 2 Fuel Oil	S002
B008a	Boiler 8a, (Rental Package Boiler)	Low NO_X Burners with Optional Flue Gas Recirculation	87 MMBtu/Hr	Natural Gas	S002

DECLARATION OF POLICY

Pollution prevention is recognized as the preferred strategy (over pollution control) for reducing risk to air resources. Accordingly, pollution prevention measures should be integrated into air pollution control programs wherever possible, and the adoption by sources of cost-effective compliance strategies, incorporating pollution prevention, is encouraged. The Department will give expedited consideration to any permit modification request based on pollution prevention principles.

The permittee is subject to the terms and conditions set forth below. These terms and conditions constitute provisions of *Allegheny County Health Department Rules and Regulations, Article XXI Air Pollution Control*. The subject equipment has been conditionally approved for operation. The equipment shall be operated in conformity with the plans, specifications, conditions, and instructions which are part of your application, and may be periodically inspected for compliance by the Department. In the event that the terms and conditions of this permit or the applicable provisions of Article XXI conflict with the application for this permit, these terms and conditions and the applicable provisions of Article XXI shall prevail. Additionally, nothing in this permit relieves the permittee from the obligation to comply with all applicable Federal, State and Local laws and regulations.

III. GENERAL CONDITIONS

1. Prohibition of Air Pollution (§2101.11)

It shall be a violation of this permit to fail to comply with, or to cause or assist in the violation of, any requirement of this permit, or any order or permit issued pursuant to authority granted by Article XXI. The permittee shall not willfully, negligently, or through the failure to provide and operate necessary control equipment or to take necessary precautions, operate any source of air contaminants in such manner that emissions from such source:

a. Exceed the amounts permitted by this permit or by any order or permit issued pursuant to Article XXI;
b. Cause an exceedance of the ambient air quality standards established by Article XXI §2101.10; or
c. May reasonably be anticipated to endanger the public health, safety, or welfare.

2. Nuisances (§2101.13)

Any violation of any requirement of this Permit shall constitute a nuisance.

3. Definitions (§2101.20)

a. Except as specifically provided in this permit, terms used retain the meaning accorded them under the applicable provisions and requirements of Article XXI or the applicable federal or state regulation. Whenever used in this permit, or in any action taken pursuant to this permit, the words and phrases shall have the meanings stated, unless the context clearly indicates otherwise.

b. Unless specified otherwise in this permit or in the applicable regulation, the term "*year*" shall mean any twelve (12) consecutive months.

4. Certification (§2102.01)

Any report or compliance certification submitted under this permit shall contain written certification by a responsible official as to truth, accuracy, and completeness. This certification and any other certification required under this permit shall be signed by a responsible official of the source, and shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

5. Operation and Maintenance (§2105.03)

All air pollution control equipment required by this permit or Article XXI, and all equivalent compliance techniques that have been approved by the Department, shall be properly installed, maintained, and operated consistent with good air pollution control practice.

6. Conditions (§2102.03.c)

It shall be a violation of this permit giving rise to the remedies provided by Article XXI §2109.02, for any person to fail to comply with any terms or conditions set forth in this permit.

7. Transfers (§2102.03.e)

This permit shall not be transferable from one person to another, except in accordance with Article XXI §2102.03.e and in cases of change-in-ownership which are documented to the satisfaction of the Department, and shall be valid only for the specific sources and equipment for which this permit was issued. The transfer of permits in the case of change-in-ownership may be made consistent with the administrative permit amendment procedure of Article XXI §2103.14.b.

8. Effect (§2102.03.g)

Issuance of this permit shall not in any manner relieve any person of the duty to fully comply with the requirements of Article XXI or any other provision of law, nor shall it in any manner preclude or affect the right of the Department to initiate any enforcement action whatsoever for violations of Article XXI or this Permit, whether occurring before or after the issuance of such permit. Further, the issuance of this permit shall not be a defense to any nuisance action, nor shall such permit be construed as a certificate of compliance with the requirements of Article XXI or this Permit.

9. General Requirements (§2102.04.a)

It shall be a violation of this Permit giving rise to the remedies set forth in Article XXI §2109 for any person to install, modify, replace, reconstruct, or reactivate any source or air pollution control equipment to which this Permit applies unless either:

a. The Department has first issued an Installation Permit for such source or equipment; or

b. Such action is solely a reactivation of a source with a current Operating Permit, which is approved under §2103.13 of Article XXI.

10. Conditions (§2102.04.e)

Further, the initiation of installation, modification, replacement, reconstruction, or reactivation under this

Installation Permit and any reactivation plan shall be deemed acceptance by the source of all terms and conditions specified by the Department in this permit and plan.

11. Revocation (§2102.04.f)

c. The Department may, at any time, revoke this Installation Permit if it finds that:
1) Any statement made in the permit application is not true, or that material information has not been disclosed in the application;
2) The source is not being installed, modified, replaced, reconstructed, or reactivated in the manner indicated by this permit or applicable reactivation plan;
3) Air contaminants will not be controlled to the degree indicated by this permit;
4) Any term or condition of this permit has not been complied with;
5) The Department has been denied lawful access to the premises or records, charts, instruments and the like as authorized by this Permit; or

d. Prior to the date on which construction of the proposed source has commenced the Department may, revoke this Installation Permit if a significantly better air pollution control technology has become available for such source, a more stringent regulation applicable to such source has been adopted, or any other change has occurred which requires a more stringent degree of control of air contaminants.

12. Term (§2102.04.g)

This Installation Permit shall expire in 18 months if construction has not commenced within such period or shall expire 18 months after such construction has been suspended, if construction is not resumed within such period. In any event, this Installation Permit shall expire upon completion of construction, except that this Installation Permit shall authorize temporary operation to facilitate shakedown of sources and air cleaning devices, to permit operations pending issuance of a related subsequent Operating Permit, or to permit the evaluation of the air contamination aspects of the source. Such temporary operation period shall be valid for a limited time, not to exceed 180 days, but may be extended for additional limited periods, each not to exceed 120 days, except that no temporary operation shall be authorized or extended which may circumvent the requirements of this Permit.

13. Annual Installation Permit Administrative Fee (§2102.10.c & e)

No later than 30 days after the date of issuance of this Installation Permit and on or before the last day of the month in which this permit was issued in each year thereafter, during the term of this permit until a subsequent corresponding Operating Permit or amended Operating Permit is properly applied for, the owner or operator of such source shall pay to the Department, in addition to all other applicable emission and administration fees, an Annual Installation Permit Administration Fee in an amount of $750.

14. Severability Requirement (§2103.12.l)

The provisions of this permit are severable, and if any provision of this permit is determined to by a court of competent jurisdiction to be invalid or unenforceable, such a determination will not affect the remaining provisions of this permit.

15. Reporting Requirements (§2103.12.k)

a. The permittee shall submit reports of any required monitoring at least every six (6) months. All instances of deviations from permit requirements must be clearly identified in such reports. All required reports must be certified by the Responsible Official.

b. Prompt reporting of deviations from permit requirements is required, including those attributable to upset conditions as defined in this permit and Article XXI §2108.01.c, the probable cause of such deviations, and any corrective actions or preventive measures taken.

c. All reports submitted to the Department shall comply with the certification requirements of General Condition III.4 above.

d. Semiannual reports required by this permit shall be submitted to the Department as follows:

1) One semiannual report is due by April 30 of each year for the time period beginning October 1 of the previous year through March 31 of that same year.
2) One semiannual report is due by October 31 of each year for the time period beginning April 1 and ending September 30 of that same year.
3) The next semiannual report shall be due April 30, 2020 for the time period beginning on the issuance date of this permit through March 31, 2020.

e. Reports may be emailed to the Department at aqreports@alleghenycounty.us in lieu of mailing a hard copy.

16. Minor Installation Permit Modifications (§2102.10.d)

Modifications to this Installation Permit may be applied for but only upon submission of an application with a fee in the amount of $300 and where:

a. No reassessment of any control technology determination is required; and
b. No reassessment of any ambient air quality impact is required.

17. Violations (§2104.06)

The violation of any emission standard established by this Permit shall be a violation of this Permit giving rise to the remedies provided by Article §2109.02.

18. Other Requirements Not Affected (§2105.02)

Compliance with the requirements of this permit shall not in any manner relieve any person from the duty to fully comply with any other applicable federal, state, or county statute, rule, regulation, or the like, including, but not limited to, any applicable NSPSs, NESHAPs, MACTs, or Generally Achievable Control Technology standards now or hereafter established by the EPA, and any applicable requirement of BACT or LAER as provided by Article XXI, any condition contained in this Installation Permit and/or any additional or more stringent requirements contained in an order issued to such person pursuant to Part I of Article XXI.

19. Other Rights and Remedies Preserved (§2109.02.b)

Nothing in this permit shall be construed as impairing any right or remedy now existing or hereafter created in equity, common law or statutory law with respect to air pollution, nor shall any court be deprived of such jurisdiction for the reason that such air pollution constitutes a violation of this permit

20. Penalties, Fines, and Interest (§2109.07.a)

A source that fails to pay any fee required under this Permit or article XXI when due shall pay a civil penalty of 50% of the fee amount, plus interest on the fee amount computed in accordance with of Article XXI §2109.06.a.4 from the date the fee was required to be paid. In addition, the source may have its permit revoked.

21. Appeals (§2109.10)

In accordance with State Law and County regulations and ordinances, any person aggrieved by an order or other final action of the Department issued pursuant to Article XXI shall have the right to appeal the action to the Director in accordance with the applicable County regulations and ordinances.

IV. SITE LEVEL TERMS AND CONDITIONS

1. Reporting of Upset Conditions (§2103.12.k.2)

The permittee shall promptly report all deviations from permit requirements, including those attributable to upset conditions as defined in Article XXI §2108.01.c, the probable cause of such deviations, and any corrective actions or preventive measures taken.

2. Visible Emissions (§2104.01.a)

Except as provided for by Article XXI §2108.01.d pertaining to a cold start, no person shall operate, or allow to be operated, any source in such manner that the opacity of visible emissions from a flue or process fugitive emissions from such source, excluding uncombined water:

a. Equal or exceed an opacity of 20% for a period or periods aggregating more than three (3) minutes in any sixty (60) minute period; or,
b. Equal or exceed an opacity of 60% at any time.

3. Odor Emissions (§2104.04) (County-only enforceable)

No person shall operate, or allow to be operated, any source in such manner that emissions of malodorous matter from such source are perceptible beyond the property line.

4. Materials Handling (§2104.05)

The permittee shall not conduct, or allow to be conducted, any materials handling operation in such manner that emissions from such operation are visible at or beyond the property line.

5. Operation and Maintenance (§2105.03)

All air pollution control equipment required by this permit or any order under Article XXI, and all equivalent compliance techniques approved by the Department, shall be properly installed, maintained, and operated consistently with good air pollution control practice.

6. Open Burning (§2105.50)

No person shall conduct, or allow to be conducted, the open burning of any material, except where the Department has issued an Open Burning Permit to such person in accordance with Article XXI §2105.50 or where the open burning is conducted solely for the purpose of non-commercial preparation of food for human consumption, recreation, light, ornament, or provision of warmth for outside workers, and in a manner which contributes a negligible amount of air contaminants.

7. Shutdown of Control Equipment (§2108.01.b)

a. In the event any air pollution control equipment is shut down for reasons other than a breakdown, the person responsible for such equipment shall report, in writing, to the Department the intent to shut down such equipment at least 24 hours prior to the planned shutdown. Notwithstanding the submission of such report, the equipment shall not be shut down until the approval of the Department is obtained; provided, however, that no such report shall be required if the source(s) served by such air pollution control equipment is also shut down at all times that such equipment is shut down.

b. The Department shall act on all requested shutdowns as promptly as possible. If the Department does not take action on such requests within ten (10) calendar days of receipt of the notice, the request shall be deemed denied, and upon request, the owner or operator of the affected source shall have a right to appeal in accordance with the provisions of Article XI.

c. The prior report required by Site Level Condition IV.7.a above shall include:

1) Identification of the specific equipment to be shut down, its location and permit number (if permitted), together with an identification of the source(s) affected;
2) The reasons for the shutdown;
3) The expected length of time that the equipment will be out of service;
4) Identification of the nature and quantity of emissions likely to occur during the shutdown;
5) Measures, including extra labor and equipment, which will be taken to minimize the length of the shutdown, the amount of air contaminants emitted, or the ambient effects of the emissions;
6) Measures which will be taken to shut down or curtail the affected source(s) or the reasons why it is impossible or impracticable to shut down or curtail the affected source(s) during the shutdown; and
7) Such other information as may be required by the Department.

8. Breakdowns (§2108.01.c)

a. In the event that any air pollution control equipment, process equipment, or other source of air contaminants breaks down in such manner as to have a substantial likelihood of causing the emission of air contaminants in violation of this permit, or of causing the emission into the open air of potentially toxic or hazardous materials, the person responsible for such equipment or source shall immediately, but in no event later than sixty (60) minutes after the commencement of the breakdown, notify the Department of such breakdown and shall, as expeditiously as possible but in no event later than seven (7) days after the original notification, provide written notice to the Department.

b. To the maximum extent possible, all oral and written notices required shall include all pertinent facts, including:

1) Identification of the specific equipment which has broken down, its location and permit number (if permitted), together with an identification of all related devices, equipment, and other sources which will be affected.
2) The nature and probable cause of the breakdown.
3) The expected length of time that the equipment will be inoperable or that the emissions will continue.
4) Identification of the specific material(s) which are being, or are likely to be emitted, together with a statement concerning its toxic qualities, including its qualities as an irritant, and its potential for causing illness, disability, or mortality.
5) The estimated quantity of each material being or likely to be emitted.
6) Measures, including extra labor and equipment, taken or to be taken to minimize the length of the breakdown, the amount of air contaminants emitted, or the ambient effects of the emissions, together with an implementation schedule.

7) Measures being taken to shut down or curtail the affected source(s) or the reasons why it is impossible or impractical to shut down the source(s), or any part thereof, during the breakdown.

c. Notices required shall be updated, in writing, as needed to advise the Department of changes in the information contained therein. In addition, any changes concerning potentially toxic or hazardous emissions shall be reported immediately. All additional information requested by the Department shall be submitted as expeditiously as practicable.

d. Unless otherwise directed by the Department, the Department shall be notified whenever the condition causing the breakdown is corrected or the equipment or other source is placed back in operation by no later than 9:00 AM on the next County business day. Within seven (7) days thereafter, written notice shall be submitted pursuant to Paragraphs a and b above.

e. Breakdown reporting shall not apply to breakdowns of air pollution control equipment which occur during the initial startup of said equipment, provided that emissions resulting from the breakdown are of the same nature and quantity as the emissions occurring prior to startup of the air pollution control equipment.

f. In no case shall the reporting of a breakdown prevent prosecution for any violation of this permit or Article XXI.

9. Cold Start (§2108.01.d)

In the event of a cold start on any fuel-burning or combustion equipment, except stationary internal combustion engines and combustion turbines used by utilities to meet peak load demands, the person responsible for such equipment shall report in writing to the Department the intent to perform such cold start at least 24 hours prior to the planned cold start. Such report shall identify the equipment and fuel(s) involved and shall include the expected time and duration of the startup. Upon written application from the person responsible for fuel-burning or combustion equipment which is routinely used to meet peak load demands and which is shown by experience not to be excessively emissive during a cold start, the Department may waive these requirements and may instead require periodic reports listing all cold starts which occurred during the report period. The Department shall make such waiver in writing, specifying such terms and conditions as are appropriate to achieve the purposes of Article XXI. Such waiver may be terminated by the Department at any time by written notice to the applicant.

10. Monitoring of Malodorous Matter Beyond Facility Boundaries (§2104.04)

The permittee shall take all reasonable action as may be necessary to prevent malodorous matter from becoming perceptible beyond facility boundaries. Further, the permittee shall perform such observations as may be deemed necessary along facility boundaries to ensure that malodorous matter beyond the facility boundary in accordance with Article XXI §2107.13 is not perceptible and record all findings and corrective action measures taken.

11. Emissions Inventory Statements (§2108.01.e & g)

a. Emissions inventory statements in accordance with §2108.01.e shall be submitted to the Department by March 15 of each year for the preceding calendar year. The Department may require more frequent submittals if the Department determines that more frequent submissions are required by the EPA or that analysis of the data on a more frequent basis is necessary to implement the requirements of Article XXI or the Clean Air Act.

b. The failure to submit any report or update within the time specified, the knowing submission of false information, or the willful failure to submit a complete report shall be a violation of this permit giving rise to the remedies provided by Article XXI §2109.02.

12. Orders (§2108.01.f)

In addition to meeting the requirements Site Level Conditions IV.7 through IV.11, inclusive, the person responsible for any source shall, upon order by the Department, report to the Department such information as the Department may require in order to assess the actual and potential contribution of the source to air quality. The order shall specify a reasonable time in which to make such a report.

13. Violations (§2108.01.g)

The failure to submit any report or update thereof required by Site Level Conditions IV.7 through IV.12 above, inclusive, within the time specified, the knowing submission of false information, or the willful failure to submit a complete report shall be a violation of this permit giving rise to the remedies provided by Article XXI §2109.02.

14. Emissions Testing (§2108.02)

a. **Orders:** No later than 60 days after achieving full production or 120 days after startup, whichever is earlier, the permittee shall conduct, or cause to be conducted, such emissions tests as are specified by the Department to demonstrate compliance with the applicable requirements of this permit and shall submit the results of such tests to the Department in writing. Upon written application setting forth all information necessary to evaluate the application, the Department may, for good cause shown, extend the time for conducting such tests beyond 120 days after startup but shall not extend the time beyond 60 days after achieving full production. Emissions testing shall comply with all applicable requirements of Article XXI, §2108.02.e.

b. **Tests by the Department:** Notwithstanding any tests conducted pursuant to this permit, the Department or another entity designated by the Department may conduct emissions testing on any source or air pollution control equipment. At the request of the Department, the permittee shall provide adequate sampling ports, safe sampling platforms and adequate utilities for the performance of such tests.

c. **Testing Requirements:** No later than 45 days prior to conducting any tests required by this permit, the person responsible for the affected source shall submit for the Department's approval a written test protocol explaining the intended testing plan, including any deviations from standard testing procedures, the proposed operating conditions of the source during the test, calibration data for specific test equipment and a demonstration that the tests will be conducted under the direct supervision of persons qualified by training and experience satisfactory to the Department to conduct such tests. In addition, at least 30 days prior to conducting such tests, the person responsible shall notify the Department in writing of the time(s) and date(s) on which the tests will be conducted and shall allow Department personnel to observe such tests, record data, provide pre-weighed filters, analyze samples in a County laboratory and to take samples for independent analysis. Test results shall be comprehensively and accurately reported in the units of measurement specified by the applicable emission limitations of this permit.

d. Test methods and procedures shall conform to the applicable reference method set forth in this permit or Article XXI Part G, or where those methods are not applicable, to an alternative sampling and testing procedure approved by the Department consistent with Article XXI §2108.02.e.2.

e. **Violations:** The failure to perform tests as required by this permit or an order of the Department, the failure to submit test results within the time specified, the knowing submission of false information, the willful failure to submit complete results, or the refusal to allow the Department, upon presentation of a search warrant, to conduct tests, shall be a violation of this permit giving rise to the remedies provided by Article XXI §2109.02.

15. Abrasive Blasting (§2105.51)

a. Except where such blasting is a part of a process requiring an operating permit, no person shall conduct or allow to be conducted, abrasive blasting or power tool cleaning of any surface, structure, or part thereof, which has a total area greater than 1,000 square feet unless such abrasive blasting complies with all applicable requirements of Article XXI §2105.51.

b. In addition to complying with all applicable provisions of §2105.51, no person shall conduct, or allow to be conducted, abrasive blasting of any surface unless such abrasive blasting also complies with all other applicable requirements of Article XXI unless such requirements are specifically addressed by §2105.51.

16. Asbestos Abatement (§2105.62, §2105.63)

In the event of removal, encasement, or encapsulation of Asbestos-Containing Material (ACM) at a facility or in the event of the demolition of any facility, the permittee shall comply with all applicable provisions of Article XXI §2105.62 and §2105.63.

17. Volatile Organic Compound Storage Tanks (§2105.12.a)

No person shall place or store, or allow to be placed or stored, a volatile organic compound having a vapor pressure of 1.5 psia or greater under actual storage conditions in any aboveground stationary storage tank having a capacity equal to or greater than 2,000 gallons but less than or equal to 40,000 gallons, unless there is in operation on such tank pressure relief valves which are set to release at the higher of 0.7 psig of pressure or 0.3 psig of vacuum or at the highest possible pressure and vacuum in accordance with State or local fire codes, National Fire Prevention Association guidelines, or other national consensus standard approved in writing by the Department. Petroleum liquid storage vessels that are used to store produced crude oil and condensate prior to lease custody transfer are exempt from these requirements.

18. Fugitive Emissions (§2105.49)

The person responsible for a source of fugitive emissions, in addition to complying with all other applicable provisions of this permit shall take all reasonable actions to prevent fugitive air contaminants from becoming airborne. Such actions may include, but are not limited to:

a. The use of asphalt, oil, water, or suitable chemicals for dust control;
b. The paving and maintenance of roadways, parking lots and the like;
c. The prompt removal of earth or other material which has been deposited by leaks from transport,

erosion or other means;

d. The adoption of work or other practices to minimize emissions;

e. Enclosure of the source; and

f. The proper hooding, venting, and collection of fugitive emissions.

19. Episode Plans (§2106.02)

The permittee shall upon written request of the Department, submit a source curtailment plan, consistent with good industrial practice and safe operating procedures, designed to reduce emissions of air contaminants during air pollution episodes. Such plans shall meet the requirements of Article XXI §2106.02.

20. New Source Performance Standards (§2105.05)

a. It shall be a violation of this permit giving rise to the remedies provided by §2109.02 of Article XXI for any person to operate, or allow to be operated, any source in a manner that does not comply with all requirements of any applicable NSPS now or hereafter established by the EPA, except if such person has obtained from EPA a waiver pursuant to Section 111 or Section 129 of the Clean Air Act or is otherwise lawfully temporarily relieved of the duty to comply with such requirements.

b. Any person who operates, or allows to be operated, any source subject to any NSPS shall conduct, or cause to be conducted, such tests, measurements, monitoring and the like as is required by such standard. All notices, reports, test results and the like as are required by such standard shall be submitted to the Department in the manner and time specified by such standard. All information, data and the like which is required to be maintained by such standard shall be made available to the Department upon request for inspection and copying.

V. EMISSION UNIT LEVEL TERMS AND CONDITIONS

A. NO_X Limits: Natural Gas Only Boilers 1, 5 & 8a

1. Restrictions:

a. The permittee shall continue to meet the conditions of the current Title V Operating Permit #0047 not otherwise affected by the revisions in this permit. [§2102.04.b.5; §2105.06.d]

b. Natural gas combustion from each boiler 1 and 5 shall not exceed the maximum potential usage of 70,476 scf in any one-hour period and 617.37 mmscf in any consecutive twelve-month period, based on a natural gas heat content of 1,050 Btu/scf. [§2103.12.h.1]

c. NO_X emissions from the following sources shall not exceed the limitations in Table V-A-1 below: [25 pa code §129.97(g)(1); §2102.04.b.5; §2105.06.d]

TABLE V-A-1: NO_X Emission Limitations

Process	Maximum Heat Input Capacity MMBtu/hr	Emission Limit** lbs/MMBtu	Hourly Emission Limit (lb/hr)	Annual Emission Limit (tons/year)*
Boiler 1	74	0.10	7.4	32.4
Boiler 5	74	0.10	7.4	32.4

*A year is defined as any consecutive 12-month period.
**Based on the PADEP presumptive RACT limit in 25 PA. Code, Chapter 129.97(g)(1)(i)).

d. NO_X emissions from boiler 8a shall not exceed the limitations in Table V-A-2 below: [25 Pa code §129.99; §2102.04.b.5; §2105.06.d]

TABLE V-A-2: NO_X Emission Limitations

Process	Maximum Heat Input Capacity MMBtu/hr	Emission Limit** lbs/MMBtu	Hourly Emission Limit (lb/hr)	Annual Emission Limit (tons/year)*
Boiler 8a, (Rental Package Boiler)	87	0.055	4.79	20.98

*A year is defined as any consecutive 12-month period.

2. Testing Requirements:

a. The permittee shall perform nitrogen oxides emissions testing while combusting natural gas on boilers no. 1 & 5 once every five years to demonstrate compliance with the emission limitations in condition V.A.1.c. Such testing shall be conducted in accordance with applicable U.S. EPA test methods 7 through 7E or other test methods approved by the Department, §2108.02 and Site Level Condition IV.14. [§2103.12.h.1; §2108.02; §2105.06.d; 25 Pa Code §129.99; 25 Pa Code §129.100]

b. The Department reserves the right to require additional emissions testing sufficient to assure compliance with the terms and conditions of this permit. Such testing shall be performed in accordance with Article XXI §2108.02. [§2103.12.h.1]

3. Monitoring Requirements

a. The permittee shall monitor and inspect the boilers weekly to insure the physical integrity of the boilers and associated equipment and to make sure the boilers are being operated and maintained properly. Steam load and natural gas usage shall be monitored and recorded to fulfill the recording requirements of V.A.4.a below. [§2105.06; §2103.12.i]

b. The permittee shall provide Department approved instrumentation to monitor the oxygen content, CO and NO_X of the boilers exhaust on a monthly basis during operation. The oxygen content of the flue gas shall be monitored to within 3% of the measured value and be recorded to the nearest 0.1%, to ensure that the subject boilers are being operated and maintained properly. The instrumentation shall be maintained in good working condition at all times and be easily accessible. [§2103.12.i; §2105.06; 25 Pa Code §129.100]

4. Record Keeping Requirements:

a. The permittee shall keep and maintain the following data for the boilers: [§2105.06; §2103.12.j; §2103.12.h.1; 25 Pa Code §129.100]:

1) Type and amount of fuel combusted (MMscf of natural gas/day and monthly total natural gas combusted);
2) Steam load (lbs/hr, lbs/day; average daily steam load for each month);
3) Cold starts (date, time and duration of each occurrence);
4) Total operating hours, (hours/day, monthly and 12-month); and
5) Records of operation, maintenance, inspection, calibration and/or replacement of combustion equipment (e.g. burner replacement, flame pattern adjustments, and air-to-fuel ratios).

b. The permittee shall record all instances of non-compliance with the conditions of this permit upon occurrence along with corrective action taken to restore compliance. [§2105.06; §2103.12.j; §2103.12.h.1]

c. All records required under this section shall be maintained by the permittee for a period of five years following the date of such record. These records shall be made available to the Department upon request for inspection and/or copying. [§2105.06; §2103.12.j.2; §2103.12.h.1; 25 Pa Code §129.100(i)]

5. Reporting Requirements:

a. The permittee shall submit semi-annual reports to the Department in accordance with General Condition III.15. The reports shall contain all required information for the time period of the report: [§2105.06; §2103.12.k.1; 25 Pa Code §129.100]

1) Type and amount of fuel combusted (Monthly and 12-month);
2) Steam load (average daily steam load for each month);
3) Cold starts (date, time and duration of each occurrence);
4) Total operating hours.

b. The permittee shall report instances of non-compliance as required to be recorded by V.A.4.b. [§2103.12.k]

c. Reporting instances of non-compliance does not relieve the permittee of the requirement to report breakdowns in accordance with Site Level Condition IV.8, if appropriate. [§2103.12.k]

6. Work Practice Standard:

None except as provided elsewhere.

7. Additional Requirements:

None except as provided elsewhere.

B. NO_X Limits: Natural Gas Boiler 3, 6 & 7 & No.2 Fuel Oil for Emergencies.

1. Restrictions:

a. The permittee shall continue to meet the conditions of the current Title V Operating Permit #0047not otherwise affected by the revisions in this RACT permit. [§2102.04.b.5; §2105.06.d]

b. The annual capacity factor for Boiler 3 shall not exceed 50% during any consecutive twelve-month period. The annual average heat input to the natural gas burner in Boiler No.3 shall not exceed 64 MMbtu/hr or 560,640 MMbtu/yr, based on a natural gas heat content of 1,050 BTU/ft^3. Bellefield shall determine compliance with this condition by maintaining records of natural gas use for the burner. (2105.06.d; §2103.12.h.1; 25 Pa Code §129.99)

c. Natural gas combustion from boilers 3 and 7 shall not exceed the maximum potential usage in condition V.B.1.g, Table V-B-1 based on a natural gas heat content of 1,050 Btu/scf. [§2103.12.h.1]

d. Boiler no. 7 annual capacity factor shall not exceed 39% during any consecutive twelve-month period when firing natural gas. [§2105.06.d; 25 Pa Code §129.99]

e. Boiler no.7 shall be equipped with low NO_X burners that meet the emission limitation in condition V.B.1.f below. [§2105.06.d; 25 Pa Code §129.99]

f. The permittee shall not operate boiler No. 7 unless a NO_X Continuous Emission Monitoring (CEM) system is present at all times and properly operated and maintained according to 40 CFR 60, Subpart Db [§2105.06.d; §2103.12.a.2.B; 25 Pa Code §123.51; 25 Pa Code §129.99]

g. NO_X Emissions from the following sources when firing Natural Gas shall not exceed the limitations in Table V-B-1 below: [25 Pa code §129.99; §2102.04.b.5; §2105.06.d; §2103.12.h.1; §60.44b(a)(1)]

TABLE V-B-1: NO_X Emission Limitations Firing Natural Gas

Process	Maximum Heat Input Capacity MMBtu/hr	Natural Gas*** Usage	Emission Limit lbs/MMBtu	Hourly Emission Limit (lb/hr)	Annual Emission Limit (tons/year)*
Boiler 3**	128	121,905 Scf/hr 533.94 MMcf/yr	0.20	25.60	56.06
Boiler 7**	188	179,048 Scf/hr 609 MMscf/yr	0.14	26.32	44.74

*A year is defined as any consecutive 12-month period.
**Based on a case-by-case and 2012 stack test and 2014 CEM test for boiler 7 when combust natural gas
****Based on NG heating content of 1050 Btu/scf

h. Natural gas combustion from boiler 6 shall not exceed the maximum potential usage of 170,467 scf in any-one-hour period and 1,494 mmscf in any consecutive twelve-month period, based on a natural gas heat content of 1,050 Btu/scf. [§2103.12.h.1]

i. NO_X emissions from boiler 6 shall not exceed the limitations in Table V-B-2 below: [25 Pa code §129.97(g)(1); §2102.04.b.5; §2105.06.d]

TABLE V-B-2: NO_X Emission Limitations Firing Natural Gas

Process	Maximum Heat Input Capacity MMBtu/hr	Emission Limit lbs/MMBtu**	Hourly Emission Limit (lb/hr)	Annual Emission Limit (tons/year)*
Boiler 6	179	0.10	17.90	78.40

*A year is defined as any consecutive 12-month period.
**Based on the PADEP presumptive RACT limit in 25 PA. Code, Chapter 129.97(g)(1)(i)).

j. The maximum allowable fuel oil usage, which is based on the annual capacity factor of 4.91% for Boilers Nos. 3, 6 & 7 during any consecutive twelve-month period shall not exceed the limits shown in Table V-B-3 below, when firing No. 2 fuel oil. [25 Pa Code §129.97(c); §2105.06.d]

k. All fuel oil combusted shall meet current ASTM specifications for no. 2 fuel oil and have a maximum sulfur content of 0.05% by weight at all times [§60.42b(j)(2); §2105.06.d]

l. Boiler no. 3, 6 & 7 annual capacity factor shall not exceed 4.91% during any consecutive twelve-month period when firing No. 2 fuel oil. [25 Pa Code §129.97(c)(7); §2105.06.d]

m. NO_X Emissions from the following sources when firing No. 2 fuel oil for emergencies shall not exceed the limitations in Table V-B-2 below: [25 Pa code §129.97(c); §2102.04.b.5; §2105.06.d; §2103.12.h.1]

TABLE V-B-3: NO_X Emission Limitations Firing Fuel Oil

Process	Maximum Heat Input Capacity MMBtu/hr	No. 2 Fuel Oil Usage	Emission Limit lbs/MMBtu	Hourly Emission Limit (lb/hr)	Annual Emission Limit (tons/year)*
Boiler 3	119	850 gal/hr 365,500 gal/yr	0.63	74.97	16.12
Boiler 6**	179	1,280 gal/hr 550,400 gal/yr	0.28	50.12	10.78
Boiler 7	188	1,340 gal/hr 567,200 gal/yr	0.20	37.60	8.08

*A year is defined as any consecutive 12-month period.

2. Testing Requirements:

a. The permittee shall perform nitrogen oxides emissions testing while combusting natural gas on boiler no. 3 & 6 once every five years to demonstrate compliance with the emission limitations in condition V.B.1.g and V.B.1.i. Such testing shall be conducted in accordance with applicable U.S. EPA test methods 7 through 7E or other test methods approved by the Department, Article XXI §2108.02 and Site Level Condition IV.14. [25 Pa Code §129.99; 25 Pa Code §129.100; §2103.12.h.1; §2108.02; 25§2105.06.d]

b. The permittee shall perform Relative Accuracy Test Audits (RATA) of the boiler no. 7 NO_X CEMS as specified in 25 PA Code §§139.101 - 139.111 to determine compliance with the boiler

7 emission limitations in condition V.B.1.f. [§2108.03; §2105.06.d; 25 Pa Code §129.99; 25 Pa Code §129.100]

c. The Department reserves the right to require additional emissions testing sufficient to assure compliance with the terms and conditions of this permit. Such testing shall be performed in accordance with Article XXI §2108.02. [§2103.12.h.1]

3. Monitoring Requirements

a. The permittee shall monitor and inspect the boilers weekly to insure the physical integrity of the boilers and associated equipment and to make sure the boilers are being operated and maintained properly. Steam load and natural gas usage shall be monitored and recorded to fulfill the recording requirements of V.B.4.a below. [§2105.06; §2103.12.i]

b. The permittee shall provide Department approved instrumentation to monitor the oxygen content, CO and NO_X of the boilers exhaust on a monthly basis during operation. The oxygen content of the flue gas shall be monitored to within 3% of the measured value and be recorded to the nearest 0.1%, to ensure that the subject boilers are being operated and maintained properly. The instrumentation shall be maintained in good working condition at all times and be easily accessible. [§2103.12.i; §2105.06; 25 PA Code §129.100]

4. Record Keeping Requirements:

a. The permittee shall keep and maintain the following data for the boilers: [§2105.06; §2103.12.j; §2103.12.h.1; 25 Pa Code §129.100]
   1) Type and amount of fuel combusted (MMscf of natural gas/day and monthly total natural gas combusted);
   2) Steam load (lbs/hr, lbs/day; average daily steam load for each month);
   3) Cold starts (date, time and duration of each occurrence);
   4) Total operating hours, (hours/day, monthly and 12-month);
   5) Records of operation, maintenance, inspection, calibration and/or replacement of combustion equipment (e.g. burner replacement, flame pattern adjustments, and air-to-fuel ratios); and

b. The permittee shall record all instances of non-compliance with the conditions of this permit upon occurrence along with corrective action taken to restore compliance. [§2105.06; §2103.12.j; §2103.12.h.1]

c. All records required under this section shall be maintained by the permittee for a period of five years following the date of such record. These records shall be made available to the Department upon request for inspection and/or copying. [§2105.06; §2103.12.j.2; §2103.12.h.1; 25 Pa Code §129.100(i)]

5. Reporting Requirements:

a. The permittee shall submit semi-annual reports to the Department in accordance with General Condition III.15. The reports shall contain all required information for the time period of the report: [§2105.06; §2103.12.k.1]

   1) Type and amount of fuel combusted (Monthly and 12-month);
   2) Steam load (average daily steam load for each month);

3) Cold starts (date, time and duration of each occurrence);
4) Total operating hours.

b. Report instances of non-compliance as required to be recorded by V.B.4.b. [§2103.12.k]

c. Reporting instances of non-compliance does not relieve the permittee of the requirement to report breakdowns in accordance with Site Level Condition IV.8, if appropriate. [§2103.12.k]

6. Work Practice Standard:

None except as provided elsewhere.

7. Additional Requirements:

None except as provided elsewhere.

C. Emergency Generators

Process Description: Two (2) Emergency Generators A & B
Facility ID: EG 1 & EG 2
Max. Design Rate: 771 hp (5.4 MMBtu/hr) each
Fuel: Diesel
Control Device: None

1. Restrictions:

a. The permittee shall continue to meet the conditions of the current Title V Operating Permit #0047 not otherwise affected by the revisions in this RACT permit. [§2102.04.b.5; §2105.06.d]

b. The permittee shall install, maintain and operate the emergency generators in accordance with the manufacturer's specifications and with good operating practices. [§2105.03; 25 PA Code §129.97 (c)]

c. The generators shall combust only diesel fuel. All diesel fuel combusted shall have a maximum allowable sulfur content of 0.05%, by weight. [§2103.12.h]

VI. ALTERNATIVE OPERATING SCENARIOS

None except as provided elsewhere

VII. EMISSIONS LIMITATIONS SUMMARY

The following table summarizes the annual maximum potential RACT II NO_X emissions for Boilers 1 through 8a.

TABLE VII-1: Emission Limitations Summary

Pollutant	Annual Combined** Emission Limit (tons/year)*
Nitrogen Oxides (NO_X)	299.96

*A year is defined as any consecutive 12-month period.

** Combined emission limits for Boilers 3, 6 and 7 based on worst case scenario operation of boiler on natural gas and/or fuel oil.