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RACT 2 Case-by-Case Evaluation

Installation Permit No. 0022-I003

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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: **Energy Center Pittsburgh – North Shore Plant**

RACT Plan Approval/Permit Number: **Installation Permit No. 0022-I003**

Plan Approval/Permit Issuance Date: **March 18, 2020**

TECHNICAL MATERIALS

<u>Included</u>	<u>Not Included</u>	<u>Not Applicable</u>	
<input checked="" type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	Identification of all regulated (NO _x and VOC) pollutants affected by the RACT plan (Review memo and RACT Permit)
<input checked="" type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	Quantification of the changes in plan allowable emissions from the affected sources as a result of RACT implementation. (Review Memo)
<input type="checkbox"/>	<input type="checkbox"/>	<input checked="" type="checkbox"/>	Rationale as to why applicable CTG or ACT regulation is not RACT for the facility. (Review Memo)
<input type="checkbox"/>	<input type="checkbox"/>	<input checked="" type="checkbox"/>	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)
<input type="checkbox"/>	<input type="checkbox"/>	<input checked="" type="checkbox"/>	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)
<input type="checkbox"/>	<input type="checkbox"/>	<input checked="" type="checkbox"/>	Include evidence, where necessary that emission limitations are based on continuous emission reduction technology. (Review Memo)
<input checked="" type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	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)
<input type="checkbox"/>	<input type="checkbox"/>	<input checked="" type="checkbox"/>	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)

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

ADMINISTRATIVE DOCUMENTS

<u>Attached</u>	<u>Not Attached</u>	<u>Not Applicable</u>
------------------------	--------------------------------	----------------------------------

- | | | | |
|-------------------------------------|--------------------------|--------------------------|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| <input checked="" type="checkbox"/> | <input type="checkbox"/> | <input type="checkbox"/> | <u>Signed</u> copy of final RACT Plan Approval/Operating Permit. |
| <input checked="" type="checkbox"/> | <input type="checkbox"/> | <input type="checkbox"/> | 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. |
| <input checked="" type="checkbox"/> | <input type="checkbox"/> | <input type="checkbox"/> | 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 |
| <input checked="" type="checkbox"/> | <input type="checkbox"/> | <input type="checkbox"/> | 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 |
| <input checked="" type="checkbox"/> | <input type="checkbox"/> | <input type="checkbox"/> | A separate formal certification duly signed indicating that public hearings were held. If no public hearings were held the review memo should state that. |
| <input checked="" type="checkbox"/> | <input type="checkbox"/> | <input type="checkbox"/> | 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. |
| <input checked="" type="checkbox"/> | <input type="checkbox"/> | <input type="checkbox"/> | Comment and Response Document: A compilation of EPA, company, and public comments and Department's responses to these comments. |
| <input checked="" type="checkbox"/> | <input type="checkbox"/> | <input type="checkbox"/> | Copy of RACT proposal, amendments, and other written correspondence between the Department and the facility. |



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

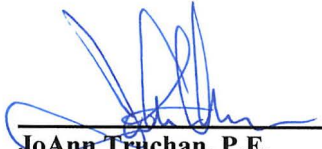
Minor Source/Minor Modification
INSTALLATION PERMIT

Issued To: **Energy Center Pittsburgh LLC**
North Shore Plant
111 South Commons
Pittsburgh, PA 15212

ACHD Permit#: **0022-I003**

Date of Issuance: **March 18, 2020**

~~Expiration Date:~~ **~~(See Section III.12)~~**

Issued By: 
JoAnn Truchan, P.E.
Section Chief, Engineering

Prepared By: 
David D. Good
Air Quality Engineer

V. EMISSION UNIT LEVEL TERMS AND CONDITIONS

Pages 2 through 16
have been redacted.

A. Boilers No. 1 & No 2

Process Description: Two identical Babcock & Wilcox, forced draft water tube boilers
Facility ID: B001, B002
Maximum Design Rate: 92.0 MMBtu/hr each
Fuel(s): Natural gas and no. 2 fuel oil as an emergency fuel
Control Device(s): None

1. Restrictions:

- a. ~~The permittee shall continue to meet the conditions of Operating Permit No. 0022, in addition to the revisions in this permit. (§2102.04.b.5)~~
- b. At no time shall the permittee allow emissions of nitrogen oxides from each boiler to exceed 0.145 pounds per MMBtu at any time. The annual nitrogen oxides limits for boiler no. 1 and boiler no. 2 are 24.4 tons and 36.7 tons, respectively, during any 12 consecutive month period. (§2105.06, 25 Pa. Code §129.99)
- c. At no time shall the permittee operate boilers no. 1 or no. 2 unless all process equipment and O₂ trim equipment are properly operated and maintained according to condition V.A.3.a. (RACT Order #220, Condition 1.2; §2105.0625 Pa. Code §129.99)
- d. At no time shall the permittee operate boiler no. 1 or no. 2 using any fuel other than natural gas with the exception of no.2 fuel oil which may be combusted only during emergency conditions and/or natural gas curtailment. (RACT Order #220, Condition 1.3; §2105.06, 25 Pa. Code §129.99)
- e. Natural gas usage in boiler no. 1 shall not exceed the maximum potential usage of 90,200 scf/hr and 395 million scf/yr. Natural gas usage in boiler no. 2 shall not exceed the maximum potential usage of 90,200 scf/hr and 514 million scf/yr. (§2103.12.h.1; §2103.12.a.2.C, 25 Pa. Code §129.99)
- f. No. 2 fuel oil combusted in each boiler shall not exceed 660 gal/hr and 330,000 gallons in any consecutive twelve-month period, at any time. All fuel oil combusted shall meet current ASTM specifications for no.2 fuel oil and contain 0.05% sulfur (wt. percent) or less. (§2103.12.h.1, 25 Pa. Code §129.99)
- g. Emissions from boiler no. 1 and boiler no. 2, shall not exceed the following limitations in Table V-A-1 or V-A-2 at any time: (§2104.02.a.1, §2105.06, §2101.02.c.4, §2103.12.a.2.B, 25 Pa. Code §129.99)

TABLE V-A-1: Boiler No. 1 Emission Limitations

POLLUTANT	Natural Gas (lb/hr)	No. 2 Fuel Oil (lb/hr)	ANNUAL EMISSION LIMIT (tons/year) ¹
Nitrogen Oxides	13.34	13.25	24.4

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

TABLE V-A-2: Boiler No. 2 Emission Limitations

POLLUTANT	Natural Gas (lb/hr)	No. 2 Fuel Oil (lb/hr)	ANNUAL EMISSION LIMIT (tons/year) ¹
Nitrogen Oxides	13.34	13.25	36.7

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

2. Testing Requirements:

- a. While combusting natural gas, the permittee shall perform NO_x emission testing on boilers no.1 & no.2, at least once every two (2) years from the most recent stack test. Such testing shall consist of methods no. 1 through no. 5 and no. 7E of appendix A of 40 CFR 60 and be conducted in accordance with such test methods and §2108.02 of Article XXI. (RACT Order #220, Condition 1.4; §2105.06; §2103.12.h.1; §2108.02 and §2103.12.i, 25 Pa. Code §129.100)
- b. ~~The permittee shall perform NO_x and particulate matter testing after accruing 40 or more operating hours in any consecutive 12-month period while firing fuel oil resulting from periods of gas curtailment or gas supply interruption in order to demonstrate compliance with the fuel oil NO_x and particulate emission limitations in conditions in conditions V.A.1.g. Such testing shall be conducted in accordance with Article XXI §2108.02 and as part of the next regularly scheduled test program required in condition V.A.2.a above. The permittee shall not be required to repeat the fuel oil testing more often than once in any five year period, unless requested to do so by the Department. (§2108.02 and §2103.12.i)~~
- e. ~~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 continuously monitor the oxygen content of the flue gas of each boiler to within 2% of actual and record the oxygen content to the nearest 0.2%, to ensure the boilers are being operated and maintained properly and are operating under the conditions demonstrated during the most recent compliance test. (§2103.12.i; §2108.03, 25 Pa. Code §129.100)

4. Record Keeping Requirements:

- a. The permittee shall keep and maintain the following data for boilers no. 1 and no.2 (RACT Order #220, Condition 1.5; §2105.06; §2103.12.h.1 and §2103.12.j, 25 Pa. Code §129.100):
 - 1) Fuel consumption (daily, monthly, and 12-month), type of fuel consumed and suppliers' certification of sulfur content, and heating value;
 - 2) Steam load, (mlbs/day, monthly average);
 - 3) Flue gas oxygen (continuously, monthly average)
 - 4) Cold starts (date, time and duration of each occurrence);
 - 5) Total operating hours, (hours/day, monthly and 12-month); and
 - 6) Records of operation, maintenance, inspection, calibration and/or replacement of combustion equipment.

7) Stack test protocols and reports.

- 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. (§2103.12.h.1, 25 Pa. Code §129.100)
- 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. [§2103.12.j.2, 25 Pa. Code §129.100]

5. Reporting Requirements:

- a. The permittee shall report the following information to the Department within thirty days of the end of each calendar half. The reports shall contain all required information for the time period of the report: (§2103.12.k.1, 25 Pa. Code §129.100)
 - 1) Monthly and 12-month data required to be recorded by condition V.A.4.a above;
 - 2) Cold start information; and
 - 3) Non-compliance information required to be recorded by V.A.4.b above.
- ~~b. 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:

The permittee shall at all times properly operate and maintain all process and emission control equipment at the facility according to good engineering practice. (25 Pa. Code §129.99)

B. Boiler No. 3

Process Description: One Babcock & Wilcox, forced draft water tube, natural gas-fired boiler
Facility ID: B003
Capacity: 131.1 MMBtu/hr
Fuel(s): Natural gas and no. 2 fuel oil as an emergency fuel
Control Device: None

1. Restrictions:

- a. ~~The permittee shall continue to meet the conditions of Operating Permit No. 0022, in addition to the revisions in this permit. [§2102.04.b.5]~~
- b. At no time shall the permittee allow emissions of nitrogen oxides from boiler 3 to exceed 0.145 pounds per MMBtu at any time and 58.3 tons during any 12 consecutive months (Condition 1.1; §2105.06, 25 Pa. Code §129.99).
- c. At no time shall the permittee operate boiler no. 3 unless all process equipment and O₂ trim equipment are properly operated and maintained according to condition V.B.3.a (RACT Order #220, Condition 1.2; §2105.06, 25 Pa. Code §129.99).
- d. At no time shall the permittee operate boiler no. 3 using any fuel other than natural gas with the exception of no.2 fuel oil which may be combusted only during emergency conditions and/or natural gas curtailment (RACT Order #220, Condition 1.3; §2105.06, 25 Pa. Code §129.99).
- e. Natural gas usage in boiler no.3 shall not exceed the maximum potential usage of 128,430 scf/hr and 1,069 million scf/yr. (§2103.12.h.1, 25 Pa. Code §129.99)
- f. No. 2 fuel oil combustion in boiler no.3 shall not exceed 940 gal/hr and 470,000 gallons in any consecutive twelve-month period, at any time. All fuel oil combusted shall meet current ASTM specifications for no.2 fuel oil and shall contain 0.05% sulfur (wt. percent) or less. (§2103.12.h.1, 25 Pa. Code §129.99)
- g. Emissions from boiler no. 3 shall not exceed the emission limitations in Table V-B-1 at any time: (§2104.02.a.1, §2105.06, §2101.02.c.4, §2103.12.a.2.B, 25 Pa. Code §129.99)

TABLE V-B-1: Boiler No. 3 Emission Limitations

POLLUTANT	Natural Gas (lb/hr)	No. 2 Fuel Oil (lb/hr)	ANNUAL EMISSION LIMIT (tons/year) ¹
Nitrogen Oxides	19.01	22.65	58.3

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

2. Testing Requirements:

- a. While combusting natural gas, the permittee shall perform NO_x emission testing on boilers no.1 & no.2, at least once every two (2) years from the most recent stack test. Such testing shall consist of methods no. 1 through no. 5 and no. 7E of appendix A of 40 CFR 60 and be conducted in accordance

with such test methods and §2108.02 of Article XXI. (RACT Order #220, Condition 1.4; §2105.06; §2103.12.h.1; §2108.02 and §2103.12.i, 25 Pa. Code §129.100)

- ~~b. The permittee shall perform NO_x and particulate matter testing on boiler No 3 after accruing 40 or more operating hours in any consecutive 12-month period while firing fuel oil resulting from periods of gas curtailment or gas supply interruption to demonstrate compliance with conditions V.B.1.b and V.B.1.g. Such testing shall be conducted in accordance with Article XXI §2108.02, and as part of the next regularly scheduled test required in condition V.B.2.a above. The permittee shall not be required to repeat the fuel oil testing more often than once in any five year period, unless requested to do so by the Department. (§2108.02 and §2103.12.i)~~
- ~~e. 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. [§2108.02]~~

3. Monitoring Requirements:

- a. The permittee shall continuously monitor the oxygen content of the flue gas of the boiler to within 2% of actual and shall record the percent oxygen content to the nearest 0.2%, to ensure the boiler is being operated and maintained properly and is operating under the conditions demonstrated during the most recent compliance test to meet the lb/MMBtu requirements of the NO_x RACT. (§2103.12.i; §2108.03; §2102.04.e, 25 Pa. Code §129.100)
- b. The permittee shall inspect boiler no.3 weekly, to insure compliance with condition V.B.1.c above. (§2103.12.i; §2102.04.e, 25 Pa. Code §129.100)

4. Record Keeping Requirements:

- a. The permittee shall keep and maintain the following data for Boiler No. 3 (RACT Order #220, Condition 1.5; §2105.06; §2103.12.h.1 and §2103.12.j, 25 Pa. Code §129.100):
 - 1) Fuel consumption (daily, monthly, and 12-month), type of fuel consumed and suppliers' certification of sulfur content and heating value;
 - 2) Steam load, (mlbs/day, monthly average);
 - 3) Flue gas oxygen (continuously, monthly average);
 - 4) Cold starts (date, time and duration of each occurrence);
 - 5) Total operating hours (hours/day), monthly and 12-month);
 - 6) Records of operation, maintenance, inspection calibration and/or replacement of combustion equipment, and
 - 7) Stack test protocols and reports.
- 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. (§2103.12.h.1, 25 Pa. Code §129.100)
- c. All records shall be retained by the facility for at least five (5) years. These records shall be made available to the Department upon request for inspection and/or copying. (§2103.12.j.2, 25 Pa. Code §129.100)

5. Reporting Requirements:

- a. The permittee shall report the following information to the Department within thirty days of the end of each calendar half. The reports shall contain all required information for the time period of the report: (§2103.12.k.1, 25 Pa. Code §129.100)
 - 1) Monthly and 12-month data required to be recorded by condition V.B.4.a above;
 - 2) Cold start information; and
 - 3) Non-compliance information required to be recorded by V.B.4.b above.
- ~~b. Until terminated by written notice from the Department, the requirement for the permittee to report cold starts 24 hours in advance in accordance with §2108.01.d is waived and the permittee may report all cold starts in accordance with Condition V.B.5.a above. (§2108.01.d, §2103.12.k.1)~~
- ~~e. 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:

The permittee shall at all times properly operate and maintain all process and emission control equipment at the facility according to good engineering practice. (25 Pa. Code §129.99)

Pages 23 through 24
have been redacted.

ALLEGHENY COUNTY HEALTH DEPARTMENT

AIR QUALITY PROGRAM

March 18, 2020

SUBJECT: Reasonable Available Control Technology (RACT II) Determination
Energy Center Pittsburgh LLC - North Shore Plant
111 South Commons
Pittsburgh, PA 15212
Allegheny County

Title V Installation Permit No. 0022- I003

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

FROM: David D. Good
Air Quality Engineer

I. Executive Summary

The Energy Center Pittsburgh LLC – North Shore Plant (Energy Center) 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

The Permittee has elected to take operational and fuel restrictions that reduce the potential NO _x emissions from Boiler Nos. 1, 2 and 3. Additional control options are not economically feasible.

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. The non-exempt sources at Energy Center are subject to presumptive RACT requirements. The facility has requested a case-by-case evaluation Boiler Nos. 1, 2 and 3, as each boiler currently does not meet the presumptive NO_x emissions limits as per 25 Pa Code 129.97. This document is the result of ACHD's determination of RACT for these three emission sources at Energy Center based on the materials submitted by the subject source and other relevant information.

III. Facility Description, Existing RACT I and Sources of NO_x

The Energy Center Pittsburgh LLC North Shore Plant is a commercial district heating and cooling plant located at 111 South Commons Avenue in the North Shore section of Pittsburgh, PA. The plant supplies steam for space heating and hospital sterilization and chilled water for summer air conditioning to commercial and institutional

sites in that area. The plant is composed of five (5) boilers, which fire natural gas as their primary fuel and have the capacity to fire no. 2 fuel oil, in lieu of natural gas at times of emergency or natural gas curtailment with the exception boilers 4 & 5. Energy Center is a major source of NO_x emissions.

On March 4th, 1996 the facility entered into a consent decree with the Department to meet RACT I obligations under RACT Order No. 220. RACT Order 220 was approved as RACT by EPA in 2001 (66 FR 52044). The RACT I requirements are listed in Table 2 below:

Table 2 RACT I Summary

Source	RACT Order 220 Condition No.	RACT I Requirement
Boiler Nos. 1, 2 and 3	I.1.1	Boiler 1 NO _x : 0.145 lb/MMBtu, 54.2 TPY Boiler 2 NO _x : 0.145 lb/MMBtu, 54.2 TPY Boiler 3 NO _x : 0.145 lb/MMBtu, 77.3 TPY
Boiler Nos. 1, 2 and 3	I.1.2	At no time shall the permittee operate boilers 1, 2 and 3 unless all process equipment and O ₂ trim equipment are properly operated and maintained according to good engineering practice.
Boiler Nos. 1, 2 and 3	I.1.3	At no time shall the permittee operate boilers 1, 2 and 3 using any fuel other than natural gas with the exception of emergency conditions and/or natural gas curtailment.
Boiler Nos. 3	I.1.4	The permittee shall conduct NO _x emission tests on Boiler 3 every 2 years.
Boiler Nos. 1, 2 and 3	I.1.5	The permittee shall maintain all records including, but not limited to: <ul style="list-style-type: none"> A. Production data on a daily basis for each boiler: <ol style="list-style-type: none"> 1. Total fuel consumption and type consumed; 2. Amount of fuel usage; 3. Steam load; and 4. Total operating hours. B. All operation, maintenance, inspection, calibration and/or replacement of fuel burning equipment.
Boiler Nos. 1, 2 and 3	I.1.6	The permittee shall maintain all appropriate records to demonstrate compliance with the requirements of both Section 2105.06 of Article XXI and this Order.

Table 3 Facility Sources Subject to Case-by-Case RACT II and Their Existing RACT I Limits

Source ID	Description	Rating	NO _x Presumptive Limit (RACT II)	NO _x Limit (RACT I) – Consent Order No. 220	Proposed Case-by-Case RACT II
B001	Forced draft, water tube boiler	92 MMBtu/hr	0.10 lb/MMBtu	0.145 lb/MMBtu, 54.2 tpy, 790 MMScf/yr	0.145 lb/MMBtu, 24.4 tpy, 395 MMScf/yr
B002	Forced draft, water tube boiler	92 MMBtu/hr	0.10 lb/MMBtu	0.145 lb/MMBtu, 54.2 tpy, 790 MMScf/yr	0.145 lb/MMBtu, 36.7 tpy, 514 MMScf/yr
B003	Forced draft, water tube boiler	131 MMBtu/hr	0.10 lb/MMBtu	0.145 lb/MMBtu, 77.3 tpy, 1,125 MMScf/yr	0.145 lb/MMBtu, 58.3 tpy, 1,069 MMScf/yr

Table 4 Facility Sources Subject to the Presumptive RACT II per PA Code 129.97

Source ID	Description	Rating	NO _x PTE (TPY)	Basis for Presumptive	Presumptive RACT Requirement (25 Pa Code Section 129.97)
P001	Three Emergency Generators	350 kW; 250 kW; and 250 kW		129.97(c)	Installation, maintenance and operation in accordance with manufacturer's specifications and good operating practice.
B004	Forced draft water tube boiler with low-NO _x Burners)	24 MMBtu/hr	4.0	129.97(b)(2)	Conduct tune-up of the boiler one time in each 5-year calendar period.
B005	Nebraska Boiler	46 MMBtu/hr (5% capacity factor)	1.15	129.97(c)	Installation, maintenance and operation in accordance with manufacturer's specifications and good operating practice.

IV. RACT Determination

Boilers 1, 2 and 3 are not able to meet the Presumptive NO_x Requirements per PA Code 129.97 of 0.10 lb/MMBtu. A case-by-case evaluation was performed for the three boilers. The NO_x emission rates from the most recent stack test (November 2017) were 0.121, 0.140 and 0.107 for Boilers 1, 2 and 3, respectively. Since the boilers historically have not operated near full load, the permittee has elected to take operational and fuel limit restrictions that reduce the annual potential NO_x emissions from each boiler. The fuel limit restrictions accepted by the permittee include restricting natural gas consumed in Boiler 1 by 50%, Boiler 2 by 35% and Boiler 3 by 5% of the maximum boiler capacity. The new baseline NO_x PTE is 24.4 tpy in Boiler 1, 36.7 tpy in Boiler 2, and 58.3 tpy in Boiler 3.

The Department evaluated technically feasible emission controls for NO_x emissions compared to the new baseline emissions. Some control options were found to be not technically feasible such as SCR (flue gas temperatures well below the effective range of control), SNCR (normal fluctuations in heating demands and steam loads make it difficult to locate necessary temperature zone for ammonia injections) and low excess air (boilers already achieve this via oxygen trim systems). A summary of those controls that were found to be technically feasible [Low NO_x Burner (LNB), Flue Gas Recirculation (FGR), Forced Draft Fan (FD), and Ultra Low NO_x Burner (ULNB)] are in Table 5 below. See Appendix A attached below for a detailed economic analysis of all feasible control options.

Table 5 RACT Analysis Summary

Source ID	Baseline NO _x Emissions (tpy)	LNB (NO _x lb/MMBtu; \$/ton)	FGR (NO _x lb/MMBtu; \$/ton)	FGR + FD Fan (NO _x lb/MMBtu; \$/ton)	FGR + FD Fan + LNB (NO _x lb/MMBtu; \$/ton)	FGR + FD Fan + ULNB (NO _x lb/MMBtu; \$/ton)
B001	24.4	0.10; \$19,687	0.10; 19,099	0.05; \$8,044	0.036; \$11,095	0.012; \$10,546
B002	36.7	0.10; \$14,698	0.10; \$14,696	0.05; \$8,259	0.036; \$9,899	0.012; \$9,283
B003	58.3	0.10; \$50,266	0.10; \$50,729	0.05; \$8,152	0.036; \$8,605	0.012; \$7,247

The new fuel limitations and annual NO_x emissions restrictions make any further control options not economically feasible. RACT II shall be the retention of the RACT I allowable emission rate of 0.145 lb/MMBTU for each boiler with the fuel restriction and annual emission limitations proposed in Table 3 above. The permittee shall at all times properly operate and maintain all process and emission control equipment at the facility according to good engineering practice

V. RACT Emissions Summary

The conditions listed in the table in Section VI of this document below supersede the relevant conditions of Plan Approval Order and Agreement No. 220, issued May 4th, 1996. The RACT II conditions are at least as stringent as

those from RACT I. Other RACT I conditions not affected by RACT II remain in effect. Based on the findings in this RACT analysis, the facility emissions can be summarized as follows:

Table 6 RACT II NO_x Emissions Reduction Summary

NO _x Potential Emissions (tpy)		
PTE Prior to RACT II	RACT Reduction	Revised PTE
214.5	66.3	148.2

As shown in Table 6, the RACT II restrictions reduced 66.3 tons of potential NO_x emissions from the facility.

VI. RACT II Permit Conditions

Source ID	Description	Permit Condition 0022-I003	RACT II Regulations
Boiler 1 & 2	Two identical Babcock & Wilcox, forced draft water tube boilers. 92.0 MMBtu/hr (each)	Condition V.A.1.b	25 PA Code §129.99
		Condition V.A.1.c	25 PA Code §129.99
		Condition V.A.1.d	25 PA Code §129.99
		Condition V.A.1.e	25 PA Code §129.99
		Condition V.A.1.f	25 PA Code §129.99
		Condition V.A.1.g	25 PA Code §129.99
		Condition V.A.2.a	25 PA Code §129.100
		Condition V.A.3.a	25 PA Code §129.100
		Condition V.A.4.a	25 PA Code §129.100
		Condition V.A.4.b	25 PA Code §129.100
		Condition V.A.4.c	25 PA Code §129.100
		Condition V.A.5.a	25 PA Code §129.100
		Condition V.A.6	25 PA Code §129.99
Boiler 3	One Babcock & Wilcox, forced draft water tube, natural gas-fired boiler. 131.1 MMBtu/hr	Condition V.A.1.b	25 PA Code §129.99
		Condition V.A.1.c	25 PA Code §129.99
		Condition V.A.1.d	25 PA Code §129.99
		Condition V.A.1.e	25 PA Code §129.99
		Condition V.A.1.f	25 PA Code §129.99
		Condition V.A.1.g	25 PA Code §129.99
		Condition V.A.2.a	25 PA Code §129.100
		Condition V.A.3.a	25 PA Code §129.100
		Condition V.A.3.b	25 PA Code §129.100
		Condition V.A.4.a	25 PA Code §129.100
		Condition V.A.4.b	25 PA Code §129.100
		Condition V.A.4.c	25 PA Code §129.100
		Condition V.A.5.a	25 PA Code §129.100
		Condition V.A.6	25 PA Code §129.99

Appendix A
(Case-by-Case Economic Evaluation for Boilers 1, 2 and 3)

Energy Center Pittsburgh
PA DEP RACT II Rule - Case-by-Case NOx RACT Proposal for Boilers 1 and 2
Table 1 - Capital Cost Estimates

Cost Item	Computation Method	Factor	Costs for Each NOx Control Option					Notes
			Option 1	Option 2	Option 3	Option 4	Option 5	
Direct Costs								
Purchased Equipment (PE)	Vendor Quote x factor	1	\$182,938	\$119,742	\$194,026	\$376,964	\$526,964	Input - B&W 2019 Vendor Quote OAQPS Control Cost Manual, Table 2.4 (Nov 2017)
Freight	PE x factor	0.05	<u>\$9,147</u>	<u>\$5,987</u>	<u>\$9,701</u>	<u>\$18,848</u>	<u>\$26,348.20</u>	
Total Purchased Equipment Costs (PEC)	Sum		\$192,085	\$125,729	\$203,727	\$395,812	\$553,312	
Installation Costs	Vendor Quote	1	\$110,872	\$160,764	\$232,831	\$395,812	\$435,394	Input - B&W 2019 Vendor Quote
Total Direct Costs (TDC)	Sum PEC + Installation Costs	1	\$302,957	\$286,493	\$436,558	\$791,624	\$988,706	
Installation Costs, Indirect								
Engineering / supervision	TDC x factor	0.10	\$30,296	\$28,649	\$43,656	\$79,162	\$98,871	OAQPS Control Cost Manual, Table 2.4 (Nov 2017)
Construction / field expenses	TDC x factor	0.10	\$30,296	\$28,649	\$43,656	\$79,162	\$98,871	OAQPS Control Cost Manual, Table 2.4 (Nov 2017)
Construction fee	TDC x factor	0.10	\$30,296	\$28,649	\$43,656	\$79,162	\$98,871	OAQPS Control Cost Manual, Table 2.4 (Nov 2017)
Start-up	TDC x factor	0.01	\$3,030	\$2,865	\$4,366	\$7,916	\$9,887.06	OAQPS Control Cost Manual, Table 2.4 (Nov 2017)
Performance test	TDC x factor		\$12,000	\$12,000	\$12,000	\$12,000	\$12,000	Plant Estimate based on current test costs
Model Study	TDC x factor	0	\$0	\$0	\$0	\$0	\$0	OAQPS Control Cost Manual, Table 2.4 (Nov 2017)
Contingencies	TDC x factor	0.2	<u>\$60,591</u>	<u>\$57,299</u>	<u>\$87,312</u>	<u>\$158,325</u>	<u>\$197,741.24</u>	Vendor quote pricing is +/- 20%
Total Indirect Costs (TIC)	Sum	0.51	\$166,508	\$158,111	\$234,645	\$415,728	\$516,240	
Total Capital Investment (TCI)	Sum TDC + TIC	1	\$469,465	\$444,605	\$671,203	\$1,207,353	\$1,504,946	

Notes:

- The Capital Cost Estimates were prepared using the methods described in the OAQPS Control Cost Manual 6th Edition and updated chapters.
- The NOx control options include the following:
 - NOx Control Option 1: New Low-NOx burner.
 - NOx Control Option 2: Re-use existing burner, re-use existing forced draft (FD) fan but install flue gas recirculation (FGR). The amount of FGR would be limited by fan capacity.
 - NOx Control Option 3: Add FGR and replace FD fan to allow greater % of flue gas recirculation.
 - NOx Control Option 4: New Low-NOx burner, new FD fan, flue gas recirculation.
 - NOx Control Option 5: New Ultra-Low-NOx burner, new FD fan, flue gas recirculation, damper/drive replacements.
- The purchased equipment costs and direct installation costs were provided by the vendor.
- The factors used to determine the freight cost and indirect installation costs (except contingency) were referenced from the OAQPS Control Cost Manual, Table 2.4 (Nov 2017).
- The factor used to determine the indirect installation cost for contingency was provided by the vendor.
- The costs are the same for Boilers 1 and 2.

Energy Center Pittsburgh
PA DEP RACT II Rule - Case-by-Case NOx RACT Proposal for Boiler 3
Table 1 - Capital Cost Estimates

Cost Item	Computation Method	Factor	Costs for Each NOx Control Option					Notes
			Option 1	Option 2	Option 3	Option 4	Option 5	
Direct Costs								
Purchased Equipment (PE)	Vendor Quote x factor	1	\$194,026	\$119,742	\$210,656	\$404,682	\$554,682	Input - B&W 2019 Vendor Quote
Freight	PE x factor	0.05	<u>\$9,701</u>	<u>\$5,987</u>	<u>\$10,533</u>	<u>\$20,234</u>	<u>\$27,734.10</u>	OAQPS Control Cost Manual, Table 2.4 (Nov 2017)
Total Purchased Equipment Costs (PEC)	Sum		\$203,727	\$125,729	\$221,189	\$424,916	\$582,416	
Installation Costs	Vendor Quote	1	\$110,872	\$160,764	\$252,788	\$426,856	\$469,542	Input - B&W 2019 Vendor Quote
	Sum PEC + Installation Costs							
Total Direct Costs (TDC)		1	\$314,599	\$286,493	\$473,977	\$851,772	\$1,051,958	
Installation Costs, Indirect								
Engineering / supervision	TDC x factor	0.10	\$31,460	\$28,649	\$47,398	\$85,177	\$105,196	OAQPS Control Cost Manual, Table 2.4 (Nov 2017)
Construction / field expenses	TDC x factor	0.10	\$31,460	\$28,649	\$47,398	\$85,177	\$105,196	OAQPS Control Cost Manual, Table 2.4 (Nov 2017)
Construction fee	TDC x factor	0.10	\$31,460	\$28,649	\$47,398	\$85,177	\$105,196	OAQPS Control Cost Manual, Table 2.4 (Nov 2017)
Start-up	TDC x factor	0.01	\$3,146	\$2,865	\$4,740	\$8,518	\$10,520	OAQPS Control Cost Manual, Table 2.4 (Nov 2017)
Performance test	TDC x factor		\$12,000	\$12,000	\$12,000	\$12,000	\$12,000	Plant Estimate based on current test costs
Model Study	TDC x factor	0	\$0	\$0	\$0	\$0	\$0	OAQPS Control Cost Manual, Table 2.4 (Nov 2017)
Contingencies	TDC x factor	0.2	<u>\$62,920</u>	<u>\$57,299</u>	<u>\$94,795</u>	<u>\$170,354</u>	<u>\$210,391.62</u>	Vendor quote pricing is +/- 20%
Total Indirect Costs (TIC)	Sum	0.51	\$172,446	\$158,111	\$253,728	\$446,404	\$548,499	
Total Capital Investment (TCI)	Sum TDC + TIC	1	\$487,045	\$444,605	\$727,705	\$1,298,176	\$1,600,457	

Notes:

- The Capital Cost Estimates were prepared using the methods described in the OAQPS Control Cost Manual 6th Edition and updated chapters.
- The NOx control options include the following:
 - NOx Control Option 1: New Low-NOx burner.
 - NOx Control Option 2: Re-use existing burner, re-use existing forced draft (FD) fan but install flue gas recirculation (FGR). The amount of FGR would be limited by fan capacity.
 - NOx Control Option 3: Add FGR and replace FD fan to allow greater % of flue gas recirculation.
 - NOx Control Option 4: New Low-NOx burner, new FD fan, flue gas recirculation.
 - NOx Control Option 5: New Ultra-Low-NOx burner, new FD fan, flue gas recirculation, damper/drive replacements.
- The purchased equipment costs and direct installation costs were provided by the vendor.
- The factors used to determine the freight cost and indirect installation costs (except contingency) were referenced from the OAQPS Control Cost Manual, Table 2.4 (Nov 2017).
- The factor used to determine the indirect installation cost for contingency was provided by the vendor.

Energy Center Pittsburgh
PA DEP RACT II Rule - Case-by-Case NOx RACT Proposal for Boiler 1
Table 2 - Annualized Cost Estimates

Cost Item	Computation Method	Factor	Costs for Each NOx Control Option					Notes
			Option 1	Option 2	Option 3	Option 4	Option 5	
Direct Operating Costs								
Operating Labor - Operator (OL)	(0.5 man-hours / shift) x (equivalent shifts / yr) x factor	65.00	\$4,063	\$4,063	\$4,063	\$4,063	\$4,063	OAQPS Control Cost Manual; factor = typical loaded labor rate (\$/hr)
Operating Labor - Supervision	OL x factor	0.15	\$609.38	\$609	\$609	\$609	\$609	OAQPS Control Cost Manual
Maintenance Labor (ML)	(0.5 man-hours / shift) x (equivalent shifts / yr) x factor	65.00	\$4,063	\$4,063	\$4,063	\$4,063	\$4,063	OAQPS Control Cost Manual; factor = typical loaded labor rate (\$/hr)
Maintenance Materials	100% of ML	1	\$4,063	\$4,063	\$4,063	\$4,063	\$4,063	OAQPS Control Cost Manual
Utilities - Electricity								
Additional Fan Power	Calculation - see below	1						OAQPS Control Cost Manual (Equation 2.10); factor = typical electricity cost (\$/KWh)
KWh	KWh x factor	0.11	<u>\$0</u>	<u>\$986</u>	<u>\$3,566</u>	<u>\$3,566</u>	<u>\$3,566</u>	
Total Direct Operating Costs (DOC)	Sum		\$12,797	\$13,783	\$16,363	\$16,363	\$16,363	
Indirect Operating Costs								
Overhead	(OL + ML) x factor	0.60	\$4,875	\$4,875	\$4,875	\$4,875	\$4,875	OAQPS Control Cost Manual (Section 2.6.5.7)
Insurance	TCI x factor	0.01	\$4,695	\$4,446	\$6,712	\$12,074	\$15,049	OAQPS Control Cost Manual
Administration	TCI x factor	0.02	\$9,389	\$8,892	\$13,424	\$24,147	\$30,099	OAQPS Control Cost Manual
Capital Recovery	TCI x factor	0.10979	<u>\$51,543</u>	<u>\$48,813</u>	<u>\$73,691</u>	<u>\$132,555</u>	<u>\$165,228</u>	Factor per OAQPS Control Cost Manual (Equation 2.8)
Total Indirect Operating Costs (IOC)	Sum		\$70,502	\$67,026	\$98,702	\$173,651	\$215,251	
Total Annualized Cost (TAC)	Sum DOC+ IOC	1	\$83,298	\$80,809	\$115,065	\$190,014	\$231,614	

Notes:

- The Annualized Cost Estimates were prepared using the methods described in the OAQPS Control Cost Manual 6th Edition and updated chapters.
- The NOx control options include the following:
 - NOx Control Option 1: New Low-NOx burner.
 - NOx Control Option 2: Re-use existing burner, re-use existing forced draft (FD) fan but install flue gas recirculation (FGR). The amount of FGR would be limited by fan capacity.
 - NOx Control Option 3: Add FGR and replace FD fan to allow greater % of flue gas recirculation.
 - NOx Control Option 4: New Low-NOx burner, new FD fan, flue gas recirculation.
 - NOx Control Option 5: New Ultra-Low-NOx burner, new FD fan, flue gas recirculation, damper/drive replacements.
- The direct operating costs use the following assumptions:
 - Operating hours per year 1000 operating hours / yr
 - Equivalent shifts per year 125
- The man-hours per shift for the Operating Labor and Maintenance Labor were estimated from examples in the OAQPS Control Cost Manual.
- The direct costs related to utilities were determined using Equation 2.10 from Section 2.6.5.4 of the OAQPS Control Cost Manual (Section 2, Chapter 1) updated Nov 2017. Equation 2.10 is shown below:

$$C_e = \frac{0.746 * Q * \Delta P * s * \theta * p_e}{6356 * \eta}$$

Where:

Q = gas flow rate (acfm)
P = pressure drop through system (in. H2O)
s = specific gravity of gas relative to air
θ = operating factors (hr/yr)
η = combined fan and motor efficiency (usually 0.6 to 0.7)
p_e = electricity cost (\$/kw-hr)

The direct costs related to utilities for Options 1-5 are shown below:

Option 1: There is no additional fan power associated with the low-NOx burner.

Option 2: FGR (4.5% recirculation rate)

Gas flow rate, Q (acfm)	38,197	per 2017 compliance stack test
ΔP (in. H2O)	1.3	Engineering estimate
Additional Fan Power (kWh)	8,966	0.746 x acfm x ΔP x operating hours / (6356 x 0.65)

Options 3 & 4 with 15% FGR (w and wo LNB); Option 5 with 30% FGR

Gas flow rate, Q (acfm)	38,197	per 2017 compliance stack test
ΔP (in. H2O)	4.7	Engineering estimate
Additional Fan Power (kWh)	32,417	0.746 x acfm x ΔP x operating hours / (6356 x 0.65)
Capital Recovery Factor	0.10979	$i(1+i)^n / ((1+i)^n - 1)$
Equipment Life, n (years)	15	
Annual Compounded Interest, i (%)	7%	

Energy Center Pittsburgh
PA DEP RACT II Rule - Case-by-Case NOx RACT Proposal for Boiler 2
Table 2 - Annualized Cost Estimates **

			Costs for Each NOx Control Option					
Cost Item	Computation Method	Factor	Option 1	Option 2	Option 3	Option 4	Option 5	Notes
Direct Operating Costs								
Operating Labor - Operator (OL)	(0.5 man-hours / shift) x (equivalent shifts / yr) x factor	65.00	\$20,313	\$20,313	\$20,313	\$20,313	\$20,313	OAQPS Control Cost Manual; factor = typical loaded labor rate (\$/hr)
Operating Labor - Supervision	OL x factor	0.15	\$3,047	\$3,047	\$3,047	\$3,047	\$3,047	OAQPS Control Cost Manual
Maintenance Labor (ML)	(0.5 man-hours / shift) x (equivalent shifts / yr) x factor	65.00	\$20,313	\$20,313	\$20,313	\$20,313	\$20,313	OAQPS Control Cost Manual; factor = typical loaded labor rate (\$/hr)
Maintenance Materials	100% of ML	1	\$20,313	\$20,313	\$20,313	\$20,313	\$20,313	OAQPS Control Cost Manual
Utilities - Electricity								
Additional Fan Power	Calculation - see below	1						OAQPS Control Cost Manual (Equation 2.10);
KWh	KWh x factor	0.11	\$0	\$3,458	\$12,501	\$12,501	\$12,501	Factor = typical electricity cost (\$/KWh)
Total Direct Operating Costs (DOC)	Sum		\$63,984	\$67,442	\$76,486	\$76,486	\$76,486	
Indirect Operating Costs								
Overhead	(OL + ML) x factor	0.60	\$24,375	\$24,375	\$24,375	\$24,375	\$24,375	OAQPS Control Cost Manual (Section 2.6.5.7)
Insurance	TCI x factor	0.01	\$4,695	\$4,446	\$6,712	\$12,074	\$15,049	OAQPS Control Cost Manual
Administration	TCI x factor	0.02	\$9,389	\$8,892	\$13,424	\$24,147	\$30,099	OAQPS Control Cost Manual
Capital Recovery	TCI x factor	0.10979	\$51,543	\$48,813	\$73,691	\$132,555	\$165,228	Factor per OAQPS Control Cost Manual (Equation 2.8)
Total Indirect Operating Costs (IOC)	Sum		\$90,002	\$86,526	\$118,202	\$193,151	\$234,751	
Total Annualized Cost (TAC)	Sum DOC+ IOC	1	\$153,986	\$153,969	\$194,688	\$269,637	\$311,237	

Notes:

- The Annualized Cost Estimates were prepared using the methods described in the OAQPS Control Cost Manual 6th Edition and updated chapters.
- The NOx control options include the following:
 - NOx Control Option 1: New Low-NOx burner.
 - NOx Control Option 2: Re-use existing burner, re-use existing forced draft (FD) fan but install flue gas recirculation (FGR). The amount of FGR would be limited by fan capacity.
 - NOx Control Option 3: Add FGR and replace FD fan to allow greater % of flue gas recirculation.
 - NOx Control Option 4: New Low-NOx burner, new FD fan, flue gas recirculation.
 - NOx Control Option 5: New Ultra-Low-NOx burner, new FD fan, flue gas recirculation, damper/drive replacements.
- The direct operating costs use the following assumptions:
 - Operating hours per year 5000 operating hours / yr
 - Equivalent shifts per year 625
- The man-hours per shift for the Operating Labor and Maintenance Labor were estimated from examples in the OAQPS Control Cost Manual.
- The direct costs related to utilities were determined using Equation 2.10 from Section 2.6.5.4 of the OAQPS Control Cost Manual (Section 2, Chapter 1) updated Nov 2017. Equation 2.10 is shown below:

$$C_e = \frac{0.746 * Q * \Delta P * s * \theta * p_e}{6356 * \eta}$$

Where:

Q = gas flow rate (acfm)
P = pressure drop through system (in. H2O)
s = specific gravity of gas relative to air
θ = operating factors (hr/yr)
η = combined fan and motor efficiency (usually 0.6 to 0.7)
p_e = electricity cost (\$/kw-hr)

The direct costs related to utilities for Options 1-5 are shown below:

Option 1: There is no additional fan power associated with the low-NOx burner.

Option 2: FGR (4.5% recirculation rate)

Gas flow rate, Q (acfm)	26,783	per 2017 compliance stack test
ΔP (in. H2O)	1.3	Engineering estimate
Additional Fan Power (kWh)	31,435	0.746 x acfm x ΔP x operating hours / (6356 x 0.65)

Options 3 & 4 with 15% FGR (w and wo LNB); Option 5 with 30% FGR

Gas flow rate, Q (acfm)	26,783	per 2017 compliance stack test
ΔP (in. H2O)	4.7	Engineering estimate
Additional Fan Power (kWh)	113,650	0.746 x acfm x ΔP x operating hours / (6356 x 0.65)
Capital Recovery Factor	0.10979	i(1+i) ⁿ / ((1+i) ⁿ -1)
Equipment Life, n (years)	15	
Annual Compounded Interest, i (%)	7%	

Energy Center Pittsburgh
PA DEP RACT II Rule - Case-by-Case NOx RACT Proposal for Boiler 3
Table 2 - Annualized Cost Estimates **

			Costs for Each NOx Control Option					
Cost Item	Computation Method	Factor	Option 1	Option 2	Option 3	Option 4	Option 5	Notes
<u>Direct Operating Costs</u>								
Operating Labor - Operator (OL)	(0.5 man-hours / shift) x (equivalent shifts / yr) x factor	65.00	\$28,438	\$28,438	\$28,438	\$28,438	\$28,438	OAQPS Control Cost Manual; factor = typical loaded labor rate (\$/hr)
Operating Labor - Supervision	OL x factor	0.15	\$4,266	\$4,266	\$4,266	\$4,266	\$4,266	OAQPS Control Cost Manual
Maintenance Labor (ML)	(0.5 man-hours / shift) x (equivalent shifts / yr) x factor	65.00	\$28,438	\$28,438	\$28,438	\$28,438	\$28,438	OAQPS Control Cost Manual; factor = typical loaded labor rate (\$/hr)
Maintenance Materials	100% of ML	1	\$28,438	\$28,438	\$28,438	\$28,438	\$28,438	OAQPS Control Cost Manual
<u>Utilities - Electricity</u>								
Additional Fan Power	Calculation - see below	1						OAQPS Control Cost Manual (Equation 2.10);
KWh	KWh x factor	0.11	<u>\$0</u>	<u>\$7,699</u>	<u>\$27,834</u>	<u>\$27,834</u>	<u>\$27,834</u>	Factor = typical electricity cost (\$/KWh)
Total Direct Operating Costs (DOC)	Sum		\$89,578	\$97,277	\$117,412	\$117,412	\$117,412	
<u>Indirect Operating Costs</u>								
Overhead	(OL + ML) x factor	0.60	\$34,125	\$34,125	\$34,125	\$34,125	\$34,125	OAQPS Control Cost Manual (Section 2.6.5.7)
Insurance	TCI x factor	0.01	\$4,870	\$4,446	\$7,277	\$12,982	\$16,005	OAQPS Control Cost Manual
Administration	TCI x factor	0.02	\$9,741	\$8,892	\$14,554	\$25,964	\$32,009	OAQPS Control Cost Manual
Capital Recovery	TCI x factor	0.10979	<u>\$53,473</u>	<u>\$48,813</u>	<u>\$79,895</u>	<u>\$142,527</u>	<u>\$175,714</u>	Factor per OAQPS Control Cost Manual (Equation 2.8)
Total Indirect Operating Costs (IOC)	Sum		\$102,209	\$96,276	\$135,851	\$215,597	\$257,853	
Total Annualized Cost (TAC)	Sum DOC+ IOC	1	\$191,787	\$193,553	\$253,263	\$333,009	\$375,265	

Notes:

- The Annualized Cost Estimates were prepared using the methods described in the OAQPS Control Cost Manual 6th Edition and updated chapters.
- The NOx control options include the following:
 - NOx Control Option 1: New Low-NOx burner.
 - NOx Control Option 2: Re-use existing burner, re-use existing forced draft (FD) fan but install flue gas recirculation (FGR). The amount of FGR would be limited by fan capacity.
 - NOx Control Option 3: Add FGR and replace FD fan to allow greater % of flue gas recirculation.
 - NOx Control Option 4: New Low-NOx burner, new FD fan, flue gas recirculation.
 - NOx Control Option 5: New Ultra-Low-NOx burner, new FD fan, flue gas recirculation, damper/drive replacements.
- The direct operating costs use the following assumptions:
 - Operating hours per year: 7000 operating hours / yr
 - Equivalent shifts per year: 875
- The man-hours per shift for the Operating Labor and Maintenance Labor were estimated from examples in the OAQPS Control Cost Manual.
- The direct costs related to utilities were determined using Equation 2.10 from Section 2.6.5.4 of the OAQPS Control Cost Manual (Section 2, Chapter 1) updated Nov 2017. Equation 2.10 is shown below:

$$C_e = \frac{0.746 * Q * \Delta P * s * \theta * p_e}{6356 * \eta}$$

Where:

Q = gas flow rate (acfm)
P = pressure drop through system (in. H2O)
s = specific gravity of gas relative to air
θ = operating factors (hr/yr)
η = combined fan and motor efficiency (usually 0.6 to 0.7)
p_e = electricity cost (\$/kw-hr)

The direct costs related to utilities for Options 1-5 are shown below:

Option 1: There is no additional fan power associated with the low-NOx burner.

Option 2: FGR (4.5% recirculation rate)

Gas flow rate, Q (acfm)	42,593	per 2017 compliance stack test
ΔP (in. H2O)	1.3	Engineering estimate
Additional Fan Power (kW)	69,988	0.746 x acfm x ΔP x operating hours / (6356 x 0.65)

Options 3 & 4 with 15% FGR (w and wo LNB); Option 5 with 30% FGR

Gas flow rate, Q (acfm)	42,593	per 2017 compliance stack test
ΔP (in. H2O)	4.7	Engineering estimate
Additional Fan Power (kW)	253,032	0.746 x acfm x ΔP x operating hours / (6356 x 0.65)
Capital Recovery Factor	0.10979	i(1+i) ⁿ / ((1+i) ⁿ - 1)
Equipment Life, n (years)	15	
Annual Compounded Interest, i (%)	7%	

Energy Center Pittsburgh
PA DEP RACT II Rule - Case-by-Case NOx RACT Proposal for Boiler 1
Table 3 - Cost-Effectiveness Estimates

Control Option No.	Description	Fuel ¹	Boiler Capacity (MMBtu/hr)	Max. Fuel Use Based on Capacity (MMScf/Yr) ²	Fuel Use with Restriction (MMScf/Yr) ³	Current NOx Emission Rate (lb/MMBtu) ⁴	Baseline NOx Emissions (tons/yr) ⁵	Controlled NOx Emission Rate (lb/MMBtu) ⁶	NOx Emissions Post-Control (tons/yr) ⁷	Total Annualized Cost (\$/yr) ⁸	Cost Effectiveness (\$ / ton NOx Reduced)	
											Average	Incremental
1	Low-NOx Burner (LNB)	Natural Gas	92	790	395	0.121	24.4	0.100	20.1	\$83,298	\$19,687	
2	FGR with existing FD Fan	Natural Gas	92	790	395	0.121	24.4	0.100	20.1	\$80,809	\$19,099	Infinite
3	FGR + FD fan	Natural Gas	92	790	395	0.121	24.4	0.050	10.1	\$115,065	\$8,044	\$3,400
4	FGR + FD fan + LNB	Natural Gas	92	790	395	0.121	24.4	0.036	7.3	\$190,014	\$11,095	\$26,571
5	FGR + FD fan + ULNB	Natural Gas	92	790	395	0.121	24.4	0.012	2.4	\$231,614	\$10,546	\$8,603

Notes:

- Fuel oil is not included in this analysis; Title V operating permit #0022, Conditions V.B.1.f and V.C.1.f restrict the use of no. 2 fuel oil in Boilers, 1, 2, and 3 to “a backup fuel in emergency situations, including where natural gas is not available or during periods of natural gas curtailment. During periods of curtailment, the permittee shall use their natural gas allotment as specified by the curtailment notice before combusting No. 2 fuel oil.”
- Maximum natural gas burned calculated based on boiler capacity calculated as follows:
Maximum Natural Gas Burned (MMScf/year) = Boiler Capacity (MMBtu/hr) * 8,760 hours/year / Heating Value (Btu/scf), where
Natural Gas Heating Value (Btu/scf): 1020
- RACT II Proposal includes a percent fuel reduction restriction of permitted fuel capacity. Proposed percent reduction: 50%
Natural Gas Burned with Fuel Use Restriction (MMScf/year) = Maximum Natural Gas Burned based on Boiler Capacity (MMBtu/hr) * (1-% Reduction)
- Per Section 129.92(b)(4)(iii), the baseline emissions rate shall be established using either test results or approved emission factors and historic operating data. The baseline emission rate is from stack test data performed on 11/9/2017.
- Baseline Annual NOx Emissions (TPY) = Fuel Use with Restriction (MMScf/Year) * Baseline NOx Emission Rate (lb/MMBtu) * Heating Value (Btu/scf) / 2000 lbs/ton
- Post-control NOx emission rates are vendor guarantees for natural gas firing.
- NOx Emissions Post-Control (TPY) = Fuel Use with Restriction (MMScf/Year) * Controlled NOx Emission Rate (lb/MMBtu) * Heating Value (Btu/scf) / 2000 lbs/ton
- Annualized costs are summarized here and were calculated in Tables 1 and 2.

Energy Center Pittsburgh

PA DEP RACT II Rule - Case-by-Case NOx RACT Proposal for Boiler 2

Table 3 - Cost-Effectiveness Estimates

Control Option No.	Description	Fuel ¹	Boiler Capacity (MMBtu/hr)	Max. Fuel Use Based on Capacity (MMScf/Yr) ²	Fuel Use with Restriction (MMScf/Yr) ³	Current NOx Emission Rate (lb/MMBtu) ⁴	Baseline NOx Emissions (tons/yr) ⁵	Controlled NOx Emission Rate (lb/MMBtu) ⁶	NOx Emissions Post-Control (tons/yr) ⁷	Total Annualized Cost (\$/yr) ⁸	Cost Effectiveness (\$ / ton NOx Reduced)	
											Average	Incremental
1	Low-NOx Burner (LNB)	Natural Gas	92	790	514	0.14	36.7	0.100	26.2	\$153,986	\$14,698	XXXX
2	FGR with existing FD Fan	Natural Gas	92	790	514	0.14	36.7	0.100	26.2	\$153,969	\$14,696	Infinite
3	FGR + FD fan	Natural Gas	92	790	514	0.14	36.7	0.050	13.1	\$194,688	\$8,259	\$3,109
4	FGR + FD fan + LNB	Natural Gas	92	790	514	0.14	36.7	0.036	9.4	\$269,637	\$9,899	\$20,439
5	FGR + FD fan + ULNB	Natural Gas	92	790	514	0.14	36.7	0.012	3.1	\$311,237	\$9,283	\$6,618

Notes:

1. Fuel oil is not included in this analysis; Title V operating permit #0022, Conditions V.B.1.f and V.C.1.f restrict the use of no. 2 fuel oil in Boilers, 1, 2, and 3 to "a backup fuel in emergency situations, including where natural gas is not available or during periods of natural gas curtailment. During periods of curtailment, the permittee shall use their natural gas allotment as specified by the curtailment notice before combusting No. 2 fuel oil."

2. Maximum natural gas burned calculated based on boiler capacity calculated as follows:

Maximum Natural Gas Burned (MMScf/year) = Boiler Capacity (MMBtu/hr) * 8,760 hours/year / Heating Value (Btu/scf), where

Natural Gas Heating Value (Btu/scf): 1020

3. RACT II Proposal includes a percent fuel reduction restriction of permitted fuel capacity. Proposed percent reduction: 35%

Natural Gas Burned with Fuel Use Restriction (MMScf/year) = Maximum Natural Gas Burned based on Boiler Capacity (MMBtu/hr) * (1-% Reduction)

4. Per Section 129.92(b)(4)(iii), the baseline emissions rate shall be established using either test results or approved emission factors and historic operating data. The baseline emission rate is from stack test data performed on 11/9/2017.

5. Baseline Annual NOx Emissions (TPY) = Fuel Use with Restriction (MMScf/Year) * Baseline NOx Emission Rate (lb/MMBtu) * Heating Value (Btu/scf) / 2000 lbs/ton

6. Post-control NOx emission rates are vendor guarantees for natural gas firing.

7. NOx Emissions Post-Control (TPY) = Fuel Use with Restriction (MMScf/Year) * Controlled NOx Emission Rate (lb/MMBtu) * Heating Value (Btu/scf) / 2000 lbs/ton

8. Annualized costs are summarized here and were calculated in Tables 1 and 2.

Energy Center Pittsburgh
PA DEP RACT II Rule - Case-by-Case NOx RACT Proposal for Boiler 3
Table 3 - Cost-Effectiveness Estimates

Control Option No.	Description	Fuel ¹	Boiler Capacity (MMBtu/hr)	Max. Fuel Use Based on Capacity (MMScf/Yr) ²	Fuel Use with Restriction (MMScf/Yr) ³	Current NOx Emission Rate (lb/MMBtu) ⁴	Baseline NOx Emissions (tons/yr) ⁵	Controlled NOx Emission Rate (lb/MMBtu) ⁶	NOx Emissions Post-Control (tons/yr) ⁷	Total Annualized Cost (\$/yr) ⁸	Cost Effectiveness (\$ / ton NOx Reduced)	
											Average	Incremental
1	Low-NOx Burner (LNB)	Natural Gas	131.1	1125	1069	0.107	58.3	0.100	54.5	\$191,787	\$50,266	
2	FGR with existing FD Fan	Natural Gas	131.1	1125	1069	0.107	58.3	0.100	54.5	\$193,553	\$50,729	Infinite (neg.)
3	FGR + FD fan	Natural Gas	131.1	1125	1069	0.107	58.3	0.050	27.3	\$253,263	\$8,152	\$2,191
4	FGR + FD fan + LNB	Natural Gas	131.1	1125	1069	0.107	58.3	0.036	19.6	\$333,009	\$8,605	\$10,450
5	FGR + FD fan + ULNB	Natural Gas	131.1	1125	1069	0.107	58.3	0.012	6.5	\$375,265	\$7,247	\$3,230

Notes:

- Fuel oil is not included in this analysis; Title V operating permit #0022, Conditions V.B.1.f and V.C.1.f restrict the use of no. 2 fuel oil in Boilers, 1, 2, and 3 to "a backup fuel in emergency situations, including where natural gas is not available or during periods of natural gas curtailment. During periods of curtailment, the permittee shall use their natural gas allotment as specified by the curtailment notice before combusting No. 2 fuel oil."
- Maximum natural gas burned calculated based on boiler capacity calculated as follows:
Maximum Natural Gas Burned (MMScf/year) = Boiler Capacity (MMBtu/hr) * 8,760 hours/year / Heating Value (Btu/scf), where
Natural Gas Heating Value (Btu/scf): 1020
- RACT II Proposal includes a percent fuel reduction restriction of permitted fuel capacity. Proposed percent reduction: 5%
- Natural Gas Burned with Fuel Use Restriction (MMScf/year) = Maximum Natural Gas Burned based on Boiler Capacity (MMBtu/hr) * (1-% Reduction)
- Per Section 129.92(b)(4)(iii), the baseline emissions rate shall be established using either test results or approved emission factors and historic operating data. The baseline emission rate is from stack test data performed on 11/9/2017.
- Baseline Annual NOx Emissions (TPY) = Fuel Use with Restriction (MMScf/Year) * Baseline NOx Emission Rate (lb/MMBtu) * Heating Value (Btu/scf) / 2000 lbs/ton
- Post-control NOx emission rates are vendor guarantees for natural gas firing.
- NOx Emissions Post-Control (TPY) = Fuel Use with Restriction (MMScf/Year) * Controlled NOx Emission Rate (lb/MMBtu) * Heating Value (Btu/scf) / 2000 lbs/ton
- Annualized costs are summarized here and were calculated in Tables 1 and 2.

Source ID	Capacity (MMBtu/hr)	Emission Rate (lb/MMBtu)		Annual Emissions (Natural Gas Only) (TPY)				Fuel Usage (MMScf/Year)					Fuel Usage (Scf/hour)
		Actual (2017 Stack Test)	Permit Limit	2017	2018	24-Month Average	Permitted	Permitted	2017 Actual	2018 Actual	Max. Based on Capacity	Proposed	Permitted
Boiler 1	92	0.121	0.145	1.96	9.00	5.48	54.2	790	32.125	147.59638	790	395	90,200
Boiler 2	92	0.140	0.145	9.38	18.90	14.14	54.2	790	132.405	266.8136	790	514	90,200
Boiler 3	131.1	0.107	0.145	21.42	13.86	17.64	77.3	1,125	394.75	255.525425	1,125	1,069	128,430
Totals											2,705	1,977	

Max. Hours per Year: 8760

Natural Gas Heating Value (Btu/scf): 1020

Proposed fuel reduction (% reduction):
Boiler 1 50%
Boiler 2 35%
Boiler 3 5%

ALLEGHENY COUNTY HEALTH DEPARTMENT
Air Quality Program

SUMMARY OF PUBLIC COMMENTS AND DEPARTMENT RESPONSES
ON THE PROPOSED ISSUANCE OF ENERGY CENTER NORTH SHORE PLANT
INSTALLATION PERMIT NO. 0022-I003

[Notice of the opportunity for public comment appeared in the legal section of the Pittsburgh Post-Gazette on January 23, 2020. The public comment period ended on February 25, 2020.]

- 1. COMMENT:** The commenter noted that a comparison of the RACT II vs RACT I requirements must be made to ensure that there is no backsliding, as per the Clean Air Act §110(l). The commenter also noted that the draft permit did not restrict the use of no. 2 fuel oil in Boiler 1 and 2 to emergency conditions as it did in Condition V.B.1.d for Boiler 3.

RESPONSE: The Department agrees with the commenter and has modified Condition V.A.1.d to restrict no. 2 fuel oil use to periods of emergency conditions and/or natural gas curtailment.

- 2. COMMENT:** The commenter requested additional information regarding recent stack testing results on the boilers in relation to the proposed RACT emission standard of 0.145 lb/MMBtu. The commenter also requested further information on how the baseline emission rates were calculated.

RESPONSE: The NO_x emission rates (3-run averages) achieved during the 2013, 2015 and 2017 compliance tests were 0.137, 0.132 and 0.121 lb/MMBtu for Boiler 1, 0.127, 0.126 and 0.140 lb/MMBtu for Boiler 2 and 0.112, 0.132 and 0.107 for Boiler 3, respectively. Each boiler had at least one average test result among those compliance tests that achieved compliance by a margin that was less than 10% of the 0.145 lb/MMBtu RACT I emission limit.

The baseline emission rates were calculated using the 2017 test results and the fuel restriction(s) that the facility elected to accept on each boiler, which is congruent with the procedures per 25 Pa Code 129.92(b)(4)(iii). The facility is required to keep records fuel use and perform biannual tests to show compliance with both the restricted fuel usage and baseline emissions. The Department has attached the entire emissions and economic analysis (as Appendix A) to the technical support document.

- 3. COMMENT:** The commenter requested additional detail regarding the potential control options for the boilers and their technical feasibility. The commenter also requested a more detailed economic evaluation of the feasible control options.

RESPONSE: The Department added more detail in the technical support document regarding the control options that were deemed technically infeasible. See response to comment no. 2 regarding a more detailed RACT 2 economic analysis for the boilers.

- 4. COMMENT:** The commenter requested better substantiation in support of the RACT II determination, including calculations and relevant guidance documents.

RESPONSE: See comment nos. 2 and 3 above and the corresponding Department responses. The facility has accepted fuel restrictions and new baseline emission limits that reduce potential emissions of NO_x by 66.3 tons/year at the facility. Appendix A to the technical support document now provides a detailed analysis on the cost-effectiveness for each technically feasible control option.

David D. Good, Air Quality Engineer

List of Commenters

Name	Affiliation
Cynthia H. Stahl, PhD. Air Protection Division (Comments 1-3)	U.S. Environmental Protection Agency Region III
Joseph Otis Minott, Esq. Matthew Mehalik, Ph.D. (Comment 4)	Clean Air Council & Breathe Project



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

Minor Source/Minor Modification
INSTALLATION PERMIT

Issued To: **Energy Center Pittsburgh LLC**
North Shore Plant

ACHD Permit#: **0022-I003**

Date of Issuance: **-----**

Expiration Date: **(See Section III.12)**

Issued By: _____
JoAnn Truchan, P.E.
Section Chief, Engineering

Prepared By: _____
David D. Good
Air Quality Engineer

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AMENDMENTS:

<i>DATE</i>	<i>SECTION(S)</i>
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I. CONTACT INFORMATION

Facility Location: **Energy Center Pittsburgh LLC – North Shore Plant**
111 South Commons
Pittsburgh, PA 15212

Permittee/Owner: **Energy Center Pittsburgh LLC**
111 South Commons
Pittsburgh, PA 15212

Permittee/Operator: **Same as Above**

Responsible Official: **Brian Goss**
Title: Plant Manager
Company: Energy Center Pittsburgh LLC
Address: 111 South Commons
Pittsburgh, PA 15212
Telephone Number: 412-231-0409
Fax Number: 412-231-0428
E-mail Address: Brian.Goss@clearwayenergy.com

Facility Contact: **Brian Goss**
Title: Plant Manager
Telephone Number: 412-231-0409
Fax Number: 412-231-0428
E-mail Address: Brian.Goss@clearwayenergy.com

AGENCY ADDRESSES:

ACHD Engineer: **Hafeez Ajenifuja**
Title: Air Quality Engineer
Telephone Number: 412-578-8132
Fax Number: 412-578-8144
E-mail Address: hafeez.ajenifuja@alleghenycounty.us

ACHD Contact: **Chief Engineer**
Allegheny County Health Department
Air Quality Program
301 39th Street, Building #7
Pittsburgh, PA 15201-1891

EPA Contact: **Enforcement Programs Section (3AP12)**
USEPA Region III
1650 Arch Street
Philadelphia, PA 19103-2029

II. FACILITY DESCRIPTION

FACILITY DESCRIPTION

The Energy Center Pittsburgh LLC North Shore Plant is a commercial district heating and cooling plant located at 111 South Commons Avenue in the North Shore section of Pittsburgh, PA. The plant supplies steam for space heating and hospital sterilization and chilled water for summer air conditioning to commercial and institutional sites in that area. The plant is composed of five (5) boilers, which fire natural gas as their primary fuel and have the capacity to fire no. 2 fuel oil, in lieu of natural gas at times of emergency or natural gas curtailment with the exception boilers 4 & 5. Additional equipment used for chilled water production includes various turbines, chillers and compressors, a two 3-cell 33,000 gpm cooling tower (sharing a common basin) and a 2-cell 7,200 gpm cooling tower. The facility is a major source of nitrogen oxides (NO_x) and carbon monoxide (CO) and minor source of particulate matter (PM), particulate matter < 10 microns in dia. (PM-10), sulfur dioxide (SO₂), 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 facilities pursuant to Reasonable Available Control Technology (RACT) 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
B001	Babcock & Wilcox forced draft, water tube boiler	None	92.0 MMBtu/hr	Natural gas, No. 2 fuel oil (emergency backup)
B002	Babcock & Wilcox forced draft, water tube boiler	None	92.0 MMBtu/hr	Natural gas, No. 2 fuel oil (emergency backup)
B003	Babcock & Wilcox forced draft, water tube boiler	None	131.1 MMBtu/hr	Natural gas, No. 2 fuel oil (emergency backup)

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)

- a. 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
- b. 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 within 30 days of the end of the calendar half.
- e. Quarterly reports required by this permit shall be submitted to the Department within 30 days of the end of the calendar quarter.
- f. Reports may be emailed to the Department at aqreports@achd.net 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.

DRAFT

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 insure 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.

21. National Emission Standards for Hazardous Air Pollutants (§2104.08)

- a. The permittee shall comply with each applicable emission limitation, work practice standard, and operation and maintenance requirement of 40 CFR Part 63, Subpart DDDDD – *National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters*, CFR Part 63, Subpart UUUUU – *National Emission Standards for Hazardous Air Pollutants for Coal- and Oil-Fired electric Utility Steam Generating Units*, and CFR Part 63, Subpart ZZZZ – *National Emission Standards for Stationary Reciprocating Internal Combustion Engines*.

V. EMISSION UNIT LEVEL TERMS AND CONDITIONS

A. Boilers No. 1 & No 2

Process Description: Two identical Babcock & Wilcox, forced draft water tube boilers
Facility ID: B001, B002
Maximum Design Rate: 92.0 MMBtu/hr each
Fuel(s): Natural gas and no. 2 fuel oil as an emergency fuel
Control Device(s): None

1. Restrictions:

- a. The permittee shall continue to meet the conditions of Operating Permit No. 0022, in addition to the revisions in this permit. [§2102.04.b.5]
- b. At no time shall the permittee allow emissions of nitrogen oxides from each boiler to exceed 0.145 pounds per MMBtus at any time. The annual nitrogen oxides limits for boiler no. 1 and boiler no. 2 are 24.4 tons and 36.7 tons, respectively, during any 12 consecutive month period. (§2105.06, 25 Pa. Code §129.99).
- c. At no time shall the permittee operate boilers no. 1 or no. 2 unless all process equipment and O₂ trim equipment are properly operated and maintained according to condition V.A.3.a (RACT Order #220, Condition 1.2; §2105.0625 Pa. Code §129.99).
- d. At no time shall the permittee operate boilers 1 & 2 using any fuel other than natural gas or No.2 fuel oil (RACT Order #220, Condition 1.3; §2105.06, 25 Pa. Code §129.99).
- e. Natural gas usage in boiler no. 1 shall not exceed the maximum potential usage of 90,200 scf/hr and 395 million scf/yr. Natural gas usage in boiler no. 2 shall not exceed the maximum potential usage of 90,200 scf/hr and 514 million scf/yr. (§2103.12.h.1; §2103.12.a.2.C, 25 Pa. Code §129.99)
- f. No. 2 fuel oil combusted in each boiler shall not exceed 660 gal/hr and 330,000 gallons in any consecutive twelve-month period, at any time. All fuel oil combusted shall meet current ASTM specifications for no.2 fuel oil and contain 0.05% sulfur (wt. percent) or less. (§2103.12.h.1, 25 Pa. Code §129.99)
- g. Emissions from boiler no. 1 and boiler no. 2, shall not exceed the following limitations in Table V-A-1 or V-A-2 at any time: (§2104.02.a.1, §2105.06, §2101.02.c.4, §2103.12.a.2.B, 25 Pa. Code §129.99)

TABLE V-A-1: Boiler No. 1 Emission Limitations

POLLUTANT	Natural Gas (lb/hr)	No. 2 Fuel Oil (lb/hr)	ANNUAL EMISSION LIMIT (tons/year) ¹
Nitrogen Oxides	13.34	13.25	24.4

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

TABLE V-A-2: Boiler No. 2 Emission Limitations

POLLUTANT	Natural Gas (lb/hr)	No. 2 Fuel Oil (lb/hr)	ANNUAL EMISSION LIMIT (tons/year) ¹
Nitrogen Oxides	13.34	13.25	36.7

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

2. Testing Requirements:

- a. While combustng natural gas, the permittee shall perform NO_x emission testing on boilers no.1 & no.2, at least once every two (2) years from the most recent stack test. Such testing shall consist of methods no. 1 through no. 5 and no. 7E of appendix A of 40 CFR 60 and be conducted in accordance with such test methods and §2108.02 of Article XXI. (RACT Order #220, Condition 1.4; §2105.06; §2103.12.h.1; §2108.02 and §2103.12.i, 25 Pa. Code §129.100)
- b. The permittee shall perform NO_x and particulate matter testing after accruing 40 or more operating hours in any consecutive 12-month period while firing fuel oil resulting from periods of gas curtailment or gas supply interruption in order to demonstrate compliance with the fuel oil NO_x, and particulate emission limitations in conditions in conditions V.A.1.g. Such testing shall be conducted in accordance with Article XXI §2108.02 and as part of the next regularly-scheduled test program required in condition V.A.2.a above. The permittee shall not be required to repeat the fuel oil testing more often than once in any five year period, unless requested to do so by the Department. (§2108.02 and §2103.12.i)
- 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 continuously monitor the oxygen content of the flue gas of each boiler to within 2% of actual and record the oxygen content to the nearest 0.2%, to ensure the boilers are being operated and maintained properly and are operating under the conditions demonstrated during the most recent compliance test. (§2103.12.i; §2108.03, 25 Pa. Code §129.100)

4. Record Keeping Requirements:

- a. The permittee shall keep and maintain the following data for boilers no. 1 and no.2 (RACT Order #220, Condition 1.5; §2105.06; §2103.12.h.1 and §2103.12.j, 25 Pa. Code §129.100):
 - 1) Fuel consumption (daily, monthly, and 12-month), type of fuel consumed and suppliers' certification of sulfur content, and heating value;
 - 2) Steam load, (mlbs/day, monthly average);
 - 3) Flue gas oxygen (continuously, monthly average)
 - 4) Cold starts (date, time and duration of each occurrence);
 - 5) Total operating hours, (hours/day, monthly and 12-month); and
 - 6) Records of operation, maintenance, inspection, calibration and/or replacement of combustion equipment.
 - 7) Stack test protocols and reports.

- 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. (§2103.12.h.1, 25 Pa. Code §129.100)
- 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. [§2103.12.j.2, 25 Pa. Code §129.100]

5. Reporting Requirements:

- a. The permittee shall report the following information to the Department within thirty days of the end of each calendar half. The reports shall contain all required information for the time period of the report: (§2103.12.k.1, 25 Pa. Code §129.100)
 - 1) Monthly and 12-month data required to be recorded by condition V.A.4.a above;
 - 2) Cold start information; and
 - 3) Non-compliance information required to be recorded by V.A.4.b above.
- b. 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:

The permittee shall at all times properly operate and maintain all process and emission control equipment at the facility according to good engineering practice. (25 Pa. Code §129.99)

B. Boiler No. 3

Process Description: One Babcock & Wilcox, forced draft water tube, natural gas-fired boiler
Facility ID: B003
Capacity: 131.1 MMBtu/hr
Fuel(s): Natural gas and no. 2 fuel oil as an emergency fuel
Control Device: None

1. Restrictions:

- a. The permittee shall continue to meet the conditions of Operating Permit No. 0022, in addition to the revisions in this permit. [§2102.04.b.5]
- b. At no time shall the permittee allow emissions of nitrogen oxides from boiler 3 to exceed 0.145 pounds per MMBtu at any time and 58.3 tons during any 12 consecutive months (Condition 1.1; §2105.06, 25 Pa. Code §129.99).
- c. At no time shall the permittee operate boiler no. 3 unless all process equipment and O₂ trim equipment are properly operated and maintained according to condition V.B.3.a (RACT Order #220, Condition 1.2; §2105.06, 25 Pa. Code §129.99).
- d. At no time shall the permittee operate boiler no. 3 using any fuel other than natural gas with the exception of no.2 fuel oil which may be combusted only during emergency conditions and/or natural gas curtailment (RACT Order #220, Condition 1.3; §2105.06, 25 Pa. Code §129.99).
- e. Natural gas usage in boiler no.3 shall not exceed the maximum potential usage of 128,430 scf/hr and 1,069 million scf/yr. (§2103.12.h.1, 25 Pa. Code §129.99)
- f. No. 2 fuel oil combustion in boiler no.3 shall not exceed 940 gal/hr and 470,000 gallons in any consecutive twelve-month period, at any time. All fuel oil combusted shall meet current ASTM specifications for no.2 fuel oil and shall contain 0.05% sulfur (wt. percent) or less. (§2103.12.h.1, 25 Pa. Code §129.99)
- g. Emissions from boiler no. 3 shall not exceed the emission limitations in Table V-B-1 at any time: (§2104.02.a.1, §2105.06, §2101.02.c.4, §2103.12.a.2.B, 25 Pa. Code §129.99)

TABLE V-B-1: Boiler No. 3 Emission Limitations

POLLUTANT	Natural Gas (lb/hr)	No. 2 Fuel Oil (lb/hr)	ANNUAL EMISSION LIMIT (tons/year) ¹
Nitrogen Oxides	19.01	22.65	58.3

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

2. Testing Requirements:

- a. While combusting natural gas, the permittee shall perform NO_x emission testing on boilers no.1 & no.2, at least once every two (2) years from the most recent stack test. Such testing shall consist of methods no. 1 through no. 5 and no. 7E of appendix A of 40 CFR 60 and be conducted in accordance

with such test methods and §2108.02 of Article XXI. (RACT Order #220, Condition 1.4; §2105.06; §2103.12.h.1; §2108.02 and §2103.12.i, 25 Pa. Code §129.100)

- b. The permittee shall perform NO_x and particulate matter testing on boiler No 3 after accruing 40 or more operating hours in any consecutive 12-month period while firing fuel oil resulting from periods of gas curtailment or gas supply interruption to demonstrate compliance with conditions V.B.1.b and V.B.1.g. Such testing shall be conducted in accordance with Article XXI §2108.02, and as part of the next regularly scheduled test required in condition V.B.2.a above. The permittee shall not be required to repeat the fuel oil testing more often than once in any five year period, unless requested to do so by the Department. (§2108.02 and §2103.12.i)
- 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. [§2108.02]

3. Monitoring Requirements:

- a. The permittee shall continuously monitor the oxygen content of the flue gas of the boiler to within 2% of actual and shall record the percent oxygen content to the nearest 0.2%, to ensure the boiler is being operated and maintained properly and is operating under the conditions demonstrated during the most recent compliance test to meet the lb/MMBtu requirements of the NO_x RACT. (§2103.12.i; §2108.03; §2102.04.e, 25 Pa. Code §129.100)
- b. The permittee shall inspect boiler no.3 weekly, to insure compliance with condition V.B.1.c above. (§2103.12.i; §2102.04.e, 25 Pa. Code §129.100)

4. Record Keeping Requirements:

- a. The permittee shall keep and maintain the following data for Boiler No. 3 (RACT Order #220, Condition 1.5; §2105.06; §2103.12.h.1 and §2103.12.j, 25 Pa. Code §129.100):
 - 1) Fuel consumption (daily, monthly, and 12-month), type of fuel consumed and suppliers' certification of sulfur content and heating value;
 - 2) Steam load, (mlbs/day, monthly average);
 - 3) Flue gas oxygen (continuously, monthly average);
 - 4) Cold starts (date, time and duration of each occurrence);
 - 5) Total operating hours (hours/day), monthly and 12-month);
 - 6) Records of operation, maintenance, inspection calibration and/or replacement of combustion equipment, and
 - 7) Stack test protocols and reports.
- 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. (§2103.12.h.1, 25 Pa. Code §129.100)
- c. All records shall be retained by the facility for at least five (5) years. These records shall be made available to the Department upon request for inspection and/or copying. (§2103.12.j.2, 25 Pa. Code §129.100)

5. Reporting Requirements:

- a. The permittee shall report the following information to the Department within thirty days of the end of each calendar half. The reports shall contain all required information for the time period of the report: (§2103.12.k.1, 25 Pa. Code §129.100)
 - 1) Monthly and 12-month data required to be recorded by condition V.B.4.a above;
 - 2) Cold start information; and
 - 3) Non-compliance information required to be recorded by V.B.4.b above.
- b. Until terminated by written notice from the Department, the requirement for the permittee to report cold starts 24 hours in advance in accordance with §2108.01.d is waived and the permittee may report all cold starts in accordance with Condition V.B.5.a above. (§2108.01.d, §2103.12.k.1)
- 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:

The permittee shall at all times properly operate and maintain all process and emission control equipment at the facility according to good engineering practice. (25 Pa. Code §129.99)

VI. ALTERNATIVE OPERATING SCENARIOS

No alternative operating scenarios exist for this operation.

DRAFT

VII. EMISSIONS LIMITATIONS SUMMARY

The following table summarizes the estimated annual maximum potential emissions (which may not include fugitive) from Boilers 1, 2 and 3 at the Energy Center North Shore Plant. These annual (consecutive 12 month) potential emission estimates assume that all three boilers operate continuously according to their permit conditions.

TABLE VII-1: Boiler 1, 2 and 3 Emission Limitations Summary

POLLUTANT	ANNUAL EMISSION LIMIT (tons/year)*
Nitrogen Oxides (NO _x)	119.4

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

ALLEGHENY COUNTY HEALTH DEPARTMENT AIR QUALITY PROGRAM

January 22, 2020

SUBJECT: Reasonable Available Control Technology (RACT II) Determination
Energy Center Pittsburgh LLC - North Shore Plant
111 South Commons
Pittsburgh, PA 15212
Allegheny County

Title V Installation Permit No. 0022- I003

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

FROM: David D. Good
Air Quality Engineer

I. Executive Summary

The Energy Center Pittsburgh LLC – North Shore Plant (Energy Center) 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

The Permittee has elected to take operational and fuel restrictions that reduce the potential NO _x emissions from Boiler Nos. 1, 2 and 3. Additional control options are not economically feasible.

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. The non-exempt sources at Energy Center are subject to presumptive RACT requirements. The facility has requested a case-by-case evaluation Boiler Nos. 1, 2 and 3, as each boiler currently does not meet the presumptive NO_x emissions limits as per 25 Pa Code 129.97. This document is the result of ACHD's determination of RACT for these three emission sources at Energy Center based on the materials submitted by the subject source and other relevant information.

III. Facility Description, Existing RACT I and Sources of NO_x

The Energy Center Pittsburgh LLC North Shore Plant is a commercial district heating and cooling plant located at 111 South Commons Avenue in the North Shore section of Pittsburgh, PA. The plant supplies steam for space heating and hospital sterilization and chilled water for summer air conditioning to commercial and institutional

sites in that area. The plant is composed of five (5) boilers, which fire natural gas as their primary fuel and have the capacity to fire no. 2 fuel oil, in lieu of natural gas at times of emergency or natural gas curtailment with the exception boilers 4 & 5. Energy Center is a major source of NO_x emissions.

On March 4th, 1996 the facility entered into a consent decree with the Department to meet RACT I obligations under RACT Order No. 220. RACT Order 220 was approved as RACT by EPA in 2001 (66 FR 52044). The RACT I requirements are listed in Table 2 below:

Table 2 RACT I Summary

Source	RACT Order 214 Condition No.	RACT I Requirement
Boiler Nos. 1, 2 and 3	I.1.1	Boiler 1 NO _x : 0.145 lb/MMBtu, 54.2 TPY Boiler 2 NO _x : 0.145 lb/MMBtu, 54.2 TPY Boiler 3 NO _x : 0.145 lb/MMBtu, 77.3 TPY
Boiler Nos. 1, 2 and 3	I.1.2	At no time shall the permittee operate boilers 1, 2 and 3 unless all process equipment and O ₂ trim equipment are properly operated and maintained according to good engineering practice.
Boiler Nos. 1, 2 and 3	I.1.3	At no time shall the permittee operate boilers 1, 2 and 3 using any fuel other than natural gas with the exception of emergency conditions and/or natural gas curtailment.
Boiler Nos. 3	I.1.4	The permittee shall conduct NO _x emission tests on Boiler 3 every 2 years.
Boiler Nos. 1, 2 and 3	I.1.5	The permittee shall maintain all records including, but not limited to: <ul style="list-style-type: none"> A. Production data on a daily basis for each boiler: <ol style="list-style-type: none"> 1. Total fuel consumption and type consumed; 2. Amount of fuel usage; 3. Steam load; and 4. Total operating hours. B. All operation, maintenance, inspection, calibration and/or replacement of fuel burning equipment.
Boiler Nos. 1, 2 and 3	I.1.6	The permittee shall maintain all appropriate records to demonstrate compliance with the requirements of both Section 2105.06 of Article XXI and this Order.

Table 3 Facility Sources Subject to Case-by-Case RACT II and Their Existing RACT I Limits

Source ID	Description	Rating	NO _x Presumptive Limit (RACT II)	NO _x Limit (RACT I) – Consent Order No. 220	Proposed Case-by-Case RACT II
B001	Forced draft, water tube boiler	92 MM lb/yr	0.10 lb/MMBtu	0.145 lb/MMBtu, 54.2 tpy, 790 MMScf/yr	0.145 lb/MMBtu, 24.4 tpy, 395 MMScf/yr
B002	Forced draft, water tube boiler	92 MM lb/yr	0.10 lb/MMBtu	0.145 lb/MMBtu, 54.2 tpy, 790 MMScf/yr	0.145 lb/MMBtu, 36.7 tpy, 514 MMScf/yr
B003	Forced draft, water tube boiler	131 MM lb/yr	0.10 lb/MMBtu	0.145 lb/MMBtu, 77.3 tpy, 1,125 MMScf/yr	0.145 lb/MMBtu, 58.3 tpy, 1,069 MMScf/yr

Table 4 Facility Sources Subject to the Presumptive RACT II per PA Code 129.97

Source ID	Description	Rating	NO _x PTE (TPY)	Basis for Presumptive	Presumptive RACT Requirement (25 Pa Code Section 129.97)
P001	Three Emergency Generators	350 kW; 250 kW; and 250 kW		129.97(c)	Installation, maintenance and operation in accordance with manufacturer's specifications and good operating practice.
B004	Forced draft water tube boiler with low-NOX Burners)	24 MMBtu/hr	4.0	129.97(b)(2)	Conduct tune-up of the boiler one time in each 5-year calendar period.
B005	Nebraska Boiler	46 MMBtu/hr (5% capacity factor)	1.15	129.97(c)	Installation, maintenance and operation in accordance with manufacturer's specifications and good operating practice.

IV. RACT Determination

Boilers 1, 2 and 3 are not able to meet the Presumptive NO_x Requirements per PA Code 129.97 of 0.10 lb/MMBtu. A case-by-case evaluation was performed for the three boilers. The NO_x emission rates from the most recent stack test (November 2017) were 0.121, 0.140 and 0.107 for Boilers 1, 2 and 3, respectively. Since the boilers historically have not operated near full load, the permittee has elected to take operational and fuel limit restrictions that reduce the annual potential NO_x emissions from each boiler. The fuel limit restrictions accepted by the permittee include restricting natural gas consumed in Boiler 1 by 50%, Boiler 2 by 35% and Boiler 3 by 5% of the maximum boiler capacity. The new baseline NO_x PTE is 24.4 tpy in Boiler 1, 36.7 tpy in Boiler 2, and 58.3 tpy in Boiler 3.

The Department evaluated further emission controls for NO_x emissions. Some control options were found to be not technically feasible such as SCR (flue gas temperatures well below the effective range of control), SNCR (fluctuations in temperatures) and low excess air (boilers already use oxygen trim systems). A summary of those controls that were found to be technically feasible [Low NO_x Burner (LNB), Flue Gas Recirculation (FGR), Forced Draft Fan (FD), and Ultra Low NO_x Burner (ULNB)] are in the table below:

Table 5 RACT Analysis Summary

Source ID	Baseline NO _x Emissions (tpy)	LNB (NO _x lb/MMBtu; \$/ton)	FGR (NO _x lb/MMBtu; \$/ton)	FGR + FD Fan (NO _x lb/MMBtu; \$/ton)	FGR + FD Fan + LNB (NO _x lb/MMBtu; \$/ton)	FGR + FD Fan + ULNB (NO _x lb/MMBtu; \$/ton)
B001	24.4	0.10; \$19,687	0.10; 19,099	0.05; \$8,044	0.036; \$11,095	0.012; \$10,546
B002	36.7	0.10; \$14,698	0.10; \$14,696	0.05; \$8,259	0.036; \$9,899	0.012; \$9,283
B003	58.3	0.10; \$19,687	0.10; 19,099	0.05; \$8,044	0.036; \$11,095	0.012; \$10,546

The new fuel limitations and annual NO_x emissions restrictions make any further control options not economically feasible. RACT II shall be the retention of the RACT I allowable emission rate of 0.145 lb/MMBTU for each boiler with the fuel restriction and annual emission limitations proposed in Table 3 above. The permittee shall at all times properly operate and maintain all process and emission control equipment at the facility according to good engineering practice

V. RACT Emissions Summary

The conditions listed in the table in Section VI of this document below supersede the relevant conditions of Plan Approval Order and Agreement No. 220, issued May 4th, 1996. The RACT II conditions are at least as stringent as

those from RACT I. Other RACT I conditions not affected by RACT II remain in effect. Based on the findings in this RACT analysis, the facility emissions can be summarized as follows:

Table 6 RACT II NO_x Emissions Reduction Summary

NO _x Potential Emissions (tpy)		
PTE Prior to RACT II	RACT Reduction	Revised PTE
214.5	66.3	148.2

As shown in Table 6, the RACT II restrictions reduced 66.3 tons of potential NO_x emissions from the facility.

VI. RACT II Permit Conditions

[illegible]

Allegheny County Health Department

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

Source Information

Source Name:	NRG Energy Center Pittsburgh LLC
Source Location:	111 South Commons Avenue, Pittsburgh, PA 15212
Mailing Address:	111 South Commons Avenue, Pittsburgh, PA 15212
County:	Allegheny
NAICS Code:	22133 (Steam and Air-Conditioning Supply)
Part 70 Permit No.:	0022
Major Source:	NO _x
Permit Reviewer:	ERG/BL

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 power generation, 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

The NRG Energy Center Pittsburgh, LLC is a major source of NO_x. The facility has five (5) operating boilers and three (3) emergency generators. RACT evaluations were conducted for four (4) of these boilers. 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 ACHD RACT findings; and
- Table S3 below shows conditions considered by ACHD to be RACT

ACHD has determined that it is not necessary to conduct a RACT evaluation for Boiler No. 5 or the emergency generators. This decision was made based on the relatively low potential emissions and limits included in the operating permit, issued November 19, 2009:

- Boiler No. 5 a natural gas fired unit, whose capacity is 46.08 MMBtu/hr, operations are limited to 500 hrs/yr and to an annual NOx emissions of 1.15 tons/yr.
- Emergency generators No. 1, 2, and 3, whose capacities are from 350, 250, and 250 kW, are each limited to 500 hrs/yr and to a collective annual NOx emissions of 8.35 tons/yr.

RACT for Boiler No.5 and the three emergency generators is continued compliance with the permit limits and applicable regulatory requirements.

Table S1. NOx RACT Findings for NRG Energy Center

Unit Description	Current Controls; Now RACT	New RACT Requirements ^(a)	NOx PTE before RACT	NOx PTE after RACT
Boiler No.1	Oxygen Trim	LNB + FGR; Annual tune-up	54.2 tpy	10.8 tpy
Boiler No.2	Oxygen Trim	LNB + FGR; Annual tune-up	54.2 tpy	10.8 tpy
Boiler No.3	Oxygen Trim	LNB + FGR; Annual tune-up	77.3 tpy	15.5 tpy
Boiler No.4	Oxygen Trim; LNB; Annual tune-up	Continued operation as permitted	4.0 tpy	4.0 tpy
Total			189.7 tpy	41.1 tpy
Emission Reduction				148.6 tpy

Where PTE=potential to emit; tpy=tons per year; LNB=low NOx burners; FGR=flue gas recirculation.

(a) Detailed RACT requirements are provided in Table S3.

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)
Boilers No 1 and No 2 (each 92 MMBtu/hr)	Natural Gas	0.10	0.029
	Fuel oil	0.12	
Boiler No.3 131.1 MMBtu/hr	Natural Gas	0.10	0.029
	Fuel oil	0.12	
Boiler No.4 24 MMBtu/hr	Natural Gas	Conduct Biennial Tune-up	Continued operation as permitted ^(b)

(a) Detailed RACT requirements are provided in Table S3.

(b) Boiler No. 4 is currently equipped with an oxygen trim system and LNB; the Title V operating permit, issued November 19, 2009, limits NOx emissions to 0.038 lb/MMBtu and requires an annual adjustment on the combustion process (condition V.D.3.b). An adjustment is synonymous with a tune-up.

Table S3. Conditions Considered to be RACT

Unit Description	Current and New Permit Conditions
Boilers No 1 and No 2 (each 92 MMBtu/hr)	<ul style="list-style-type: none"> • Operate the oxygen trim system when the boiler is in use. • Burn only natural gas or No.2 fuel oil. • Burn No.2 fuel oil only as a backup fuel in emergency situations. • Natural gas input limited to 90,200 scf/hr and 790 million scf/yr. • No.2 fuel oil input limited to 660 gallons/hr. • Burn only No.2 fuel oil with a max. sulfur content of 0.05%. • NEW: Conduct an annual tune-up. • NEW: Install and operate LNB + FGR, NOx emissions for each boiler is limited to 0.029 lb/MMBtu and 10.8 tpy.
Boiler No.3 131.1 MMBtu/hr	<ul style="list-style-type: none"> • Operate the oxygen trim system when the boiler is in use. • Burn only natural gas or No.2 fuel oil. • Burn No.2 fuel oil only as a backup fuel in emergency conditions. • Natural gas input limited to 128,430 scf/hr and 1,125 million scf/yr. • No.2 fuel oil input limited to 940 gallons/hr. • Burn only No.2 fuel oil with a max. sulfur content of 0.05%. • NEW: Conduct an annual tune-up. • NEW: Install and operate LNB + FGR, NOx emissions are limited to 0.029 lb/MMBtu and 15.5 tpy.
Boiler No.4 24 MMBtu/hr	<ul style="list-style-type: none"> • Operate the oxygen trim system when the boiler is in use. • Operate low-NOx burners. • Perform an annual adjustment on the combustion process. • NOx emissions are limited to 0.038 lb/MMBtu; 0.91 lbs/hr; and 4.00 tpy. • Burn only natural gas. • Natural gas input limited to 23,530 scf/hr and 206.12 scf/yr. • Conduct tune-ups annually.

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 NRG Energy Center Pittsburgh, LLC is a commercial district heating and cooling plant located at 111 South Commons Avenue in the North Shore section of Pittsburgh, PA. This plant provides steam, hot water, and chilled water to approximately 22 commercial and institutional customers on Pittsburgh's North Side, including Allegheny General Hospital.

The plant is composed of five (5) boilers which fire natural gas as their primary fuel and have the capacity to fire no. 2 fuel oil, in lieu of natural gas at times of emergency or natural gas curtailment with the exception boilers 4 & 5. Table 1 provides additional details on these boilers and other NO_x emission units at the source.

Table 1. NO_x Emission Units at the Energy Center Power Station

ID	Unit Type	Existing Control Devices	Heat Input Capacity	Fuel	Stack ID
P001	Emergency Generators	None	350 kW 250 kW 250 kW	Fuel Oil Fuel Oil Natural Gas	-
No. 1	B&W forced draft water-tube boiler	Oxygen Trim System	92.0 MMBtu/hr	Natural Gas [Fuel Oil as Emergency Backup]	S001
No. 2	B&W forced draft water-tube boiler	Oxygen Trim System	92.0 MMBtu/hr	Natural Gas [Fuel Oil as Emergency Backup]	S002
No. 3	B&W forced draft water-tube boiler	Oxygen Trim System	131.1 MMBtu/hr	Natural Gas [Fuel Oil as Emergency Backup]	S003
No. 4	Unilux forced draft water-tube boiler	Oxygen Trim System; Low-NO _x Burners; Annual Tune-up	24.0 MMBtu/hr	Natural Gas	S004
No. 5	Nebraska Boiler	None	46.08 MMBtu/hr	Natural Gas	S005

RACT Analyses in this Document

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

ACHD has determined that it is not necessary to conduct a RACT evaluation for the following four (4) emission units. This decision was made based on the relatively low potential emissions from these units. ACHD considers it unlikely that additional controls would be technically and economically feasible for these combustion units:

- Emergency generators No. 1, 2, and 3. The total power production from these units is 850 kW. Pursuant to the operating permit, issued November 19, 2009, Condition V.A.1.f, each emergency generators operations are limited to 500 hrs/yr.
- Boiler No. 5 has a rated heat input capacity of 46.08 MMBtu and is physically located at the Allegheny General Hospital. Pursuant to the operating permit, issued November 19, 2009, Condition V.E.1.d, the boilers' operations are limited to 500 hrs/yr. Condition V.E.1.f, further restricts the boiler to 4.61 lb/hr and to 1.15 tons/yr.

RACT for Boiler No. 5 is continued compliance with existing permit conditions and Article XXI section 2105.06.d.6, which requires operation in accordance with manufacturer's specification. RACT for the three emergency generators is continued compliance with existing permit conditions and Article XXI section 2105.06.d.6 which requires operation in accordance with manufacturer's specification.

RACT analyses for NO_x have been conducted for:

- A. Boilers No. 1, 2, and 3 are equipped with Oxygen Trim Systems to control NO_x; these boilers fire natural gas with fuel oil as an emergency backup fuel; and

- B. Boiler No. 4 will be evaluated separately. It is equipped with a Low-NOx Burner and only has the ability to fire natural gas.

A. RACT for NO_x – Boilers No. 1, 2, and 3

Boilers No. 1 and 2 are Babcock and Wilcox, Type D package boilers, each with a rated heat input capacity of 92.0 MMBtu/hr. Each boiler has dual fuel capabilities; they can fire either natural gas or No. 2 fuel oil and each exhausts to its own stack, S001 and S002 respectively. Boilers 1 and 2 were installed in 1964.

Oxygen trim systems are installed on boilers No. 1 and 2. These systems automatically control fuel and air feed rates to minimize excess oxygen and reduce thermal NO_x formation. The Title V permit requires the oxygen trim equipment to be properly operated and maintained. Operation with oxygen trim is considered the baseline control for Boilers 1 and 2.

Pursuant to the Title V operating permit, issued November 19, 2009, NO_x emissions from each boiler are limited to 0.145 lb/MMBtu and 54.2 tons per year. Hourly emissions are limited to 13.25 lb/hr when burning No. 2 fuel oil and 13.34 lb/hr when burning natural gas. The Title V permit also restricts natural gas usage to 790 million scf/yr and No.2 fuel oil usage to 660 gallons/hr. No.2 fuel oil is only allowed as a backup fuel in emergency conditions.

Boiler No. 3 is a Babcock and Wilcox, Type D package boiler and has a rated heat input capacity of 131.1 MMBtu/hr. It has dual fuel capabilities; it can fire either natural gas or No. 2 fuel oil. Boiler No. 3 was installed in 1972 and exhausts to its own stack, S003. Boiler No. 3 has oxygen trim equipment, which is required to be properly operated and maintained.

Pursuant to the Title V operating permit, issued November 19, 2009, NO_x emissions from Boiler No. 3 are limited to 0.145 lb/MMBtu and 77.3 tons per year. Hourly emissions are restricted for Boiler No. 3 to 22.65 lb/hr when No. 2 fuel oil is burned and 19.01 lb/hr when natural gas is burned.

The Title V permit also restricts the natural gas usage for boiler No. 3 to 1,125 million scf/yr and No.2 fuel oil usage to 940 gallons/hr. No.2 fuel oil is only allowed as a backup fuel in emergency conditions.

Step 1 – Identify Control Options

ACHD reviewed NRG's RACT submittal¹ for these boilers and consulted several references to ensure that all possible control options were identified. ACHD reviewed EPA's Alternative Control Techniques (ACT) document for Industrial/Commercial/Institutional (ICI) Boilers² and 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 identified controls from the ACT and/or the source's RACT submittal. No additional control measures were 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.

¹ NRG Energy Center. Revised RACT Analysis In Support of Allegheny County Health Department Air Quality Program: Installation Permit Application, Title V Permit Application (modification). May, 2004.

² Alternative Control Techniques (ACT) Document – NO_x Emissions from Industrial/ Commercial/ Institutional (ICI) Boilers (EPA-453/R-94-022). <http://www.epa.gov/ttn/catc1/dir1/icboiler.pdf>, accessed January 23, 2015.

Table 2. Boilers No. 1, No. 2, and No. 3 – All NO_x Control Options

Category	Control Option	Reference ^(a)
Combustion Optimization	Reduced air preheat (RAP)	ACT
	Combustion Optimization or Tune-up	ACT+NCSU
	Low Excess Air (LEA)	ACT
Staged Combustion	Air Staging	ACT
	Fuel Staging	ACT
	Fuel Reburning	ACT+NRG
Additions To Combustion, Air or Fuel	Flue Gas Recirculation (FGR)	ACT+NRG
	Water / Steam Injection (WSI)	ACT
	Fuel Induced Recirculation (FIR)	ACT
Low-NO _x Burning	Low-NO _x Burner (LNB)	ACT+NRG
Post Combustion Control	Selective Catalytic Reduction (SCR)	ACT+NRG
	Selective Non-Catalytic Reduction (SNCR)	ACT
	SCONO _x TM	NRG

(a) ACT= EPA's Alternative Control Techniques document for Industrial/Commercial/Institutional Boilers published in 1994; NCSU= North Carolina State University who investigated the effect of tune-ups on state operated boilers; and NGR is the Revised RACT Analysis submittal dated May 2004.

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%.³

(b) Tune-ups and Combustion Optimization

The operation of combustion sources can be improved through tuning the device periodically. Tune-ups are used to improve efficiency and save money, reduce combustion emissions, and to ensure safe operations. A tune-up generally involves: conducting an evaluation of existing equipment (such as oxygen probes and other instrumentation, burners, dampers, tilt mechanisms, heat transfer

³ Alternative Control Techniques (ACT) Document – NO_x Emissions from Industrial/ Commercial/ Institutional (ICI) Boilers (EPA-453/R-94-022). <http://www.epa.gov/ttn/catc1/dir1/icboiler.pdf>, accessed January 12, 2015.

surfaces, and actuators); determining if equipment needs to be cleaned, repaired, or replaced; investigating levels of excess air and emissions of NO_x and CO; evaluating temperatures and pressures; and inspecting for leakage and condensate. The data is analyzed and adjustments are made 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).

In a study by the North Carolina State University on the effect of tune-ups on state operated boilers,⁴ 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 NO_x 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.

(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.⁵ 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 O₂ 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.

An oxygen trim system is designed to maintain LEA and continuously monitor the flue gases and adjust the burner oxygen. For example, colder air is denser and contains more oxygen than warm air. The oxygen trim system can continuously adjust to ambient and atmospheric conditions that affect oxygen/air supply.

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

⁴ 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.

⁵ 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.

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.

(f) 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.⁶

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 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

⁶ 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.

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%.⁷

(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 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).⁸

(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 temperature similarly to how FGR reduces the temperature and thermal NO_x is reduced. 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)

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.⁹

⁷ Alternative Control Techniques (ACT) Document – NO_x Emissions from Industrial/ Commercial/ Institutional (ICI) Boilers (EPA-453/R-94-022). <http://www.epa.gov/ttn/catc1/dir1/icboiler.pdf>, accessed January 12, 2015.

⁸ 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.

⁹ 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.

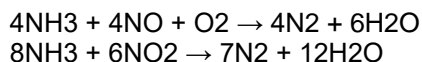
The staging results in fuel-lean and fuel-rich combustion zones in the furnace at the burner. In the fuel-lean zones, the combustion temperature is lowered, reducing the production of NO_x emissions. Both the temperature and oxygen concentrations are lowered in the fuel-rich zones. LNB technology is 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.¹⁰

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 that 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. NH₃, usually diluted with air or steam, is injected into the exhaust upstream of a catalyst bed. On the catalyst surface, NH₃ reacts with NO_x to form molecular nitrogen and water with the following basic reaction pathways:



Depending on system design, NO_x removal of 70-90% can be achieved under optimum conditions.¹¹

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 typically is designed to occur between 600°F and 750°F, depending on the catalyst.¹² 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.

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

¹⁰ Alternative Control Techniques (ACT) Document – NO_x Emissions from Industrial/ Commercial/ Institutional (ICI) Boilers (EPA-453/R-94-022). <http://www.epa.gov/ttn/catc1/dir1/icboiler.pdf>, accessed January 12, 2015.

¹¹ The Babcock & Wilcox Company. Steam Its Generation and Use, 40th Edition. Ed. S C Stultz and J B Kitto. Barberton, Ohio: 1992

¹² 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.

optimal range, oxidation of ammonia will take place resulting in an increase in NO_x emissions.

SCR catalysts 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.¹³

Units with these 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 is 30-50%.¹⁴

(m) SCONOx™

SCONOx™ is an oxidation catalyst-based technology that removes both NO_x and CO without the need for supplementary chemical reagents, such as NH₃. The SCONOx™ catalytic absorption system uses a potassium carbonate-coated catalyst to reduce NO_x emissions. The catalyst oxidizes CO to CO₂ and NO to NO₂ and potassium nitrates (KNO₃). The catalyst is regenerated by passing dilute hydrogen gas through the catalyst, which converts the KNO₂ and KNO₃ to K₂CO₃, water, and elemental nitrogen. The catalyst is renewed and available for further absorption, while the water and nitrogen are exhausted. The SCONOx system has demonstrated its ability to meet the same low emission rates as a conventional SCR/CO oxidation catalyst system without the use of NH₃.¹⁵ EMx™ (the second-generation of the SCONOx™ NO_x Absorber technology) has been commercially demonstrated on a 45 MW gas turbine in Redding, California, with NO_x emissions below 1.06 ppmv.¹⁶

¹³ Northeast States For Coordinated Air Use Management (NESCAUM), and Praveen Amar. Applicability and Feasibility of NO_x, SO₂, 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.

¹⁴ U.S. EPA. Air Pollution Control Technology Fact Sheet; Selective Non-Catalytic Reduction (EPA-452/F-03-031). 2003. <http://www.epa.gov/ttn/catc1/dir1/fsncr.pdf>, accessed January 23, 2015.

¹⁵ Eastern Research Group. Electricity Framework 5 Year Review Control Technologies Review. Prepared for Canada's Clean Air Strategic Alliance. January 2008.

¹⁶ EmeraChem Power. Public Comment submittal on IEPR Committee Workshop on the Potential Need for Emission Reduction Credits in the South Coast Air Quality Management District on 9/24/2009. http://www.energy.ca.gov/2009_energy_policy/documents/2009-09-24_workshop/comments/EmeraChem_Power_Comment_TN-53670.pdf, accessed March 18, 2015.

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, 2, and 3. It was determined that LNB, FGR, LNB+FGR, tune-ups, and SCR are technically feasible for controlling NO_x emissions. 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 Boilers No. 1, 2, and 3. This section presents the rationale explaining why each control option is not technically feasible.

(a) Reduced Air Preheat (RAP)

RAP is limited to stokers equipped with combustion air preheaters.¹⁷ Boilers No. 1, 2, and 3 use ambient (not preheated) combustion air. Therefore, RAP is removed from further consideration.

(b) LEA

Boilers No. 1, 2, and 3 are operated in low excess air condition, due to the oxygen system. Therefore, LEA is removed from further consideration.

(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.¹⁸

Boilers No. 1, 2, and 3 are packaged units with small combustion zones. 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, 2, and 3 are primarily natural gas fired. Therefore fuel re-burn is considered technically infeasible for controlling NO_x emissions.

(e) WSI

WSI can control NO_x, but it 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

¹⁷ *Id.*

¹⁸ Alternative Control Techniques (ACT) Document – NO_x Emissions from Industrial/ Commercial/ Institutional (ICI) Boilers (EPA-453/R-94-022). <http://www.epa.gov/ttn/catc1/dir1/icboiler.pdf>, accessed January 23, 2015.

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.¹⁹ Therefore, FIR is removed from further consideration.

(g) SNCR

The appropriate SNCR temperature window is approximately 1600 to 2000°F. The exhaust temperature for Boilers No. 1, 2, and 3 range from 350 to 600°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. The small boiler size and moderate combustion temperature make the residence time inadequate to achieve the required reaction in the SNCR. Furthermore, the boilers fluctuations in steam demand make ammonia injection problematic.

Therefore, SNCR is considered technically infeasible for controlling NO_x emissions.

(h) SCONO_xTM

EPA's RBLC does not have any uses of SCONO_xTM for ICI boilers.²⁰ Therefore, this is considered an undemonstrated technology for ICI boilers and is considered technically infeasible for controlling NO_x emissions.

Step 3 - Evaluate Control Options

Emissions and Emission Reductions

The three boilers have the potential to emit a total of 185.7 tons NO_x/yr. Pursuant to the Title V permit, NO_x emissions from each boiler are limited to 0.145 lb/MMBtu. In November of 2013, emission performance tests were conducted on each boiler while natural gas was fired. Tests showed that each boiler was in compliance. The average emission rate for boilers 1, 2, and 3 were 0.137, 0.127, and 0.112 lb/MMBtu, respectively.

Table 3 lists each technically feasible control options. The control efficiency, emission reduction, and final emission rate for each control option are listed.

Table 3. Boilers No. 1, 2, and 3 – 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) ^(a)
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¹⁹ 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).

²⁰ 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).

No.1 – FGR	21%	11.2	0.115
No.2 – FGR	21%	11.2	0.115
No.3 – FGR	21%	16.0	0.115
No.1 – LNB	59%	32.1	0.059
No.2 – LNB	59%	32.1	0.059
No.3 – LNB	59%	45.8	0.059
No.1 – LNB+FGR	80%	43.4	0.029
No.2 – LNB+FGR	80%	43.4	0.029
No.3 – LNB+FGR	80%	61.8	0.029
No.1 – SCR	90%	48.8	0.015
No.2 – SCR	90%	48.8	0.015
No.3 – SCR	90%	69.6	0.015
No.1 – Tune-up	2%	1.08	0.145
No.2 – Tune-up	2%	1.08	0.145
No.3 – Tune-up	2%	1.55	0.145

(a) Control efficiencies were calculated from the permit limited PTE and the controlled NO_x emission rate.

Control efficiencies were derived from RBLC emissions limits for gas-fired ICI boilers and are consistent with the control efficiency ranges in the references cited in Step 1.

Economic Analysis

Using the information provided by NRG and collected by ACHD, a thorough economic analysis of the technically feasible control option for Boilers No. 1, 2, and 3 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 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% and equipment life of 15 years.

The basis of 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 4:

Table 4. Boilers No. 1, 2, and 3 – Economic Analysis of NO_x Technically Feasible Control Options

Option	Total Capital Investment (\$)	Total Annualized Cost (\$/yr)	Potential NO _x Removal from Add-on Control (ton/yr)	Cost Effectiveness (\$/ton NO _x removed)
No.1 – FGR	181,530	56,320	11.2	5,000
No.2 – FGR	181,530	56,320	11.2	5,000
No.3 – FGR	181,530	56,320	16.0	3,500
No.1 – LNB	693,970	103,950	32.1	3,200
No.2 – LNB	693,970	103,950	32.1	3,200
No.3 – LNB	693,970	103,950	45.8	2,300
No.1 – LNB+FGR	3,177,200	676,730	148.6	4,600
No.2 – LNB+FGR				
No.3 – LNB+FGR				
No.1 – SCR	608,740	365,780	48.8	7,500
No.2 – SCR	608,740	365,780	48.8	7,500
No.3 – SCR	867,510	518,580	69.6	7,500
No.1 – Tune-up	\$6,500	2,020	1.08	1,900
No.2 – Tune-up	\$6,500	2,020	1.08	1,900
No.3 – Tune-up	\$6,500	2,020	1.55	1,300

Step 4 – Select RACT

Based on the costs shown in Table 4, installing LNB+FRG along with performing annual tune-ups are cost-effective NO_x control options for Boiler Nos. 1, 2, and 3.

The NO_x RACT for Boilers No. 1, 2, and 3 was determined to be: 1) conducting annual tune-ups for Boilers No. 1, 2, and 3; 2) installation of LNB and FGR; and 3) compliance with new NO_x emission limits of 0.029 lb/MMBtu, 10.8 tons/yr for Boilers No. 1 and 2, and 15.5 tons/yr for Boiler No. 3. With regards to tune-ups, the following applies:

- The permittee shall perform an annual adjustment on the combustion process of boiler no.4. Such annual adjustment, shall include, but not be limited to: (IP 0022-I001; §2103.12.i)
 - 1) Inspection, adjustment, cleaning, or replacement of fuel-burning equipment, including the burners and moving parts necessary for proper operation as specified by the manufacturer;
 - 2) Inspection of the flame pattern or characteristics and adjustments necessary to minimize total emissions of NO_x, and to the extent practicable minimize emissions of carbon monoxide, and;
 - 3) Inspection of the air-to-fuel ratio control system and adjustments necessary to ensure proper calibration and operation as specified by the manufacturer.
- The permittee shall record the following information for each annual adjustment required by condition V.D.3.b above: (IP 0022-I001):
 - 1) The date of the adjustment procedure;
 - 2) The name of the service company and technicians;
 - 3) The operating rate or load after adjustment;

- 4) The CO and NO_x emission rate after adjustment; and
- 5) The excess oxygen rate after adjustment.

Review of the RBLC indicates that the emission limit of 0.029 lb/MMBtu is generally consistent with the emission limits for other industrial boilers with LNB and FGR. ACHD reviewed EPA's RBLC determinations for boiler from over the last 5 years. Table 5 provides the RBLC findings.

Table 5. EPA's RBLC Findings

Source	RBLC ID	Date of Permit Issuance	NO _x Limit (lb/MMBtu)	NO _x Control
12.310 – Gas Kraton Polymers US LLC [249 MMBtu/hr]	OH-0354	1/15/13	0.120 [Oil]	LNB
			0.100 [Gas]	
12.31 – Gas Lake Charles Chemical Complex - Lab Unit [170 MMBtu/hr]	LA-0244	11/29/2010	0.1158 (hrly max.)	LNB
13.220 – Oil US DOE – Hanford [191 MMBtu/hr]	WA-0349	4/4/13	0.090 [Oil]	LNB
12.31 – Gas Cronus Chemicals, LLC [104 MMBtu/hr]	IL-0114	9/5/2014	0.0800	LNB
13.31 – Gas Carty Plant [91 MMBtu/hr]	OR-0048	12/29/2010	0.0495	LNB
13.220 – Oil Wolverine Power [72.4 MMBtu/hr]	MI-0400	6/29/11	0.023 [Oil]	LNB
12.31 – Gas Pinecrest Energy Center [150 MMBtu/hr]	TX-0641	11/12/2013	0.0190 (3% O ₂)	LNB
12.31 – Gas Karn Weadock Generating Complex [220 MMBtu/hr]	MI-0389	12/29/2009	0.0180 (30-Day Rolling)	LNB
13.31 – Gas Woodbridge Energy Center [91.6 MMBtu/hr]	NJ-0079	7/25/2012	0.0100	LNB
13.31 – Gas Thetford Generating Station [100 MMBtu/hr]	MI-0410	7/25/2013	0.0500	LNB+FGR
13.31 – Gas Hess Newark Energy Center [589 MMBtu/hr]	NJ-0080	11/1/2012	0.0500	LNB+FGR
13.31 – Gas Holland Board Of Public Works - East 5Th Street [95 MMBtu/hr]	MI-0412	12/4/2013	0.0500	LNB+FGR+ GCP
12.31 – Gas Ammonia Production Facility [217.5 MMBtu/hr]	LA-0272	3/27/2013	0.0500 (annual avg.)	LNB+FGR+ GCP
12.310 – Gas International Station Power Plant (Primary Fuel: Diesel) [12.5 MMBtu/hr]	AK-0073	12/20/10	0.0320 [Gas]	LNB+FGR
13.31 – Gas St. Joseph Energy Center, LLC [80 MMBtu/hr]	IN-0158	12/3/2012	0.0320 (3 hours)	LNB+FGR
11.31 – Gas Georgia Pacific Breton, LLC [425 MMBtu/hr]	AL-0271	6/11/2014	0.0200	LNB+FGR
13.31 – Gas Oregon Clean Energy Center	OH-0352	6/18/2013	0.0200	LNB+FGR

Source	RBLC ID	Date of Permit Issuance	NO _x Limit (lb/MMBtu)	NO _x Control
[99 MMBtu/hr]				
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
11.22 – Oil Montville Power LLC [995 MMBtu/hr]	CT-0156	4/6/2010	0.06 [Oil]	SCR
Current Operating Permit Limit	-	2009	0.145	-
Stack Test – November 2013	-	2013	0.137 0.127 0.112	-

B. RACT for NO_x – Boiler No. 4

Boiler No. 4 is a Unilux hot water boiler fitted with low-NO_x burners and an Oxygen Trim system. The boiler has a rated heat input capacity of 24.0 MMBtu. It burns only natural gas and exhausts to its own stack (i.e., S004).

Pursuant to the Title V operating permit, issued November 19, 2009, NO_x emissions are limited to 0.038 lb/MMBtu, 0.91 lb/hr, and 4.00 tons/yr. The Title V permit requires that the oxygen trim equipment be properly operated and maintained and natural gas usage be restricted to 206.12 million scf/yr. The Title V permit also requires the source to perform an annual adjustment of the combustion process. An adjustment is synonymous with a tune-up.

Step 1 – Identify Control Options

NRG's RACT submittal did not evaluate Boiler No. 4.²¹ ACHD consulted several references to ensure that all possible control options were identified for this boiler. ACHD reviewed EPA's Alternative Control Techniques (ACT) document for Industrial/Commercial/Institutional (ICI) Boilers²² and 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 identified controls from the ACT and/or the source's RACT submittal. 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

²¹ NRG Energy Center. Revised RACT Analysis In Support of Allegheny County Health Department Air Quality Program: Installation Permit Application, Title V Permit Application (modification). May, 2004.

²² Alternative Control Techniques (ACT) Document – NO_x Emissions from Industrial/ Commercial/ Institutional (ICI) Boilers (EPA-453/R-94-022). <http://www.epa.gov/ttn/catc1/dir1/icboiler.pdf>, accessed January 23, 2015.

optimization, staged combustion, additions to combustion air or fuel, low-NO_x burners, and post combustion controls.

Table 6. Boiler No. 4 – All NO_x Control Options

Category	Control Option	Reference ^(a)
Combustion Optimization	Reduced air preheat (RAP)	ACT
	Combustion Optimization or Tune-up	ACT+NCSU
	Low Excess Air (LEA)	ACT
Staged Combustion	Air Staging	ACT
	Fuel Staging	ACT
	Fuel Reburning	ACT
Additions To Combustion, Air or Fuel	Flue Gas Recirculation (FGR)	ACT
	Water / Steam Injection (WSI)	ACT
	Fuel Induced Recirculation (FIR)	ACT
Low-NO _x Burning	Low-NO _x Burner (LNB)	ACT
Post Combustion Control	Selective Catalytic Reduction (SCR)	ACT
	Selective Non-Catalytic Reduction (SNCR)	ACT

(a) ACT= EPA's Alternative Control Techniques document for Industrial/Commercial/Institutional Boilers published in 1994; NCSU= North Carolina State University who investigated the effect of tune-ups on state operated boilers; and NGR is the Revised RACT Analysis submittal dated May 2004.

Descriptions of these NO_x controls are provided in the RACT for Boilers No. 1, 2, and 3 (starting on page 8 of 24).

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 Boiler No. 4. It was determined that tune-ups, FGR, and SCR are technically feasible for controlling NO_x emissions. 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 Boiler No. 4. This section presents the rationale explaining why each control option is not technically feasible.

(a) Tune-up

Boiler No. 4 is already being tuned annual pursuant to the Title V operating permit, issued November 19, 2009 condition V.D.3.b. Therefore, conducting tune-ups is not included in the economic analysis.

(a) Reduced Air Preheat (RAP)

RAP is limited to stokers equipped with combustion air preheaters.²³ Boiler No. 4 uses ambient (not preheated) combustion air. Therefore, RAP is removed from further consideration.

(b) LEA

Boiler No. 4 is operated in low excess air condition, due to the oxygen system. Therefore, LEA is removed from further consideration.

²³ *Id.*

(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.²⁴

Although, specific information on the internal size of Boiler No. 4 was not reviewed, it is expected to have complications related to furnace geometry. 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.

Boiler No. 4 fires natural gas. Therefore fuel re-burn is considered technically infeasible for controlling NO_x emissions.

(e) WSI

WSI can control NO_x, but it 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.²⁵ 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 No. 4 is 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. The small boiler size and moderate combustion temperature make the residence time inadequate to achieve the required reaction in the SNCR. Furthermore, the boiler fluctuations in steam demand make ammonia injection problematic.

²⁴ Alternative Control Techniques (ACT) Document – NO_x Emissions from Industrial/ Commercial/ Institutional (ICI) Boilers (EPA-453/R-94-022). <http://www.epa.gov/ttn/catc1/dir1/icboiler.pdf>, accessed January 23, 2015.

²⁵ 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).

Therefore, SNCR is considered technically infeasible for controlling NO_x emissions.

Step 3 - Evaluate Control Options

Emissions and Emission Reductions

Boiler No. 4 has a potential to emit (PTE) 4.0 tons/yr NO_x and is limited 0.038 lb/MMBtu.²⁶ The operating permit does not require compliance testing.

The technically feasible control options with their estimated control efficiency are as follows:

Table 7. Boiler No. 4 – 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) ^(a)
No.4 – FGR	21%	0.8	0.030
No.4 – SCR	90%	3.6	0.004

(a) Control efficiencies were calculated from the permit limited PTE and the controlled NO_x emission rate.

(b) Percent reduction in fuel usage; therefore, the emissions on a MMBtu basis does not change

Control efficiencies were derived from RBLC emissions limits for gas fired ICI boilers and are consistent with the control efficiency ranges in the references cited in Step 1.

Economic Analysis

ACHD collected information for an economic analysis of the technically feasible control option for Boiler No. 4 - 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 components intrinsic to the complete system, the estimated annual operating costs, and the indirect annual costs. All 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). Annualized costs are based on an interest rate of 7% and equipment life of 15 years.

The basis of 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 8:

Table 8. Boiler No. 4 – Economic Analysis of NO_x Technically Feasible Control Options

Option	Total Capital Investment (\$)	Total Annualized Cost (\$/yr)	Potential NO_x Removal from Add-on Control (ton/yr)	Cost Effectiveness (\$/ton NO_x removed)
No.4 – FGR	54,900	35,320	0.8	42,700
No.4 – SCR	158,810	138,690	3.6	38,600

²⁶ NO_x emissions are limited, pursuant to the operating permit, November 19, 2009, conditions V.D.1.b and V.D.1.d.

Step 4 – Select RACT

Based on the costs shown in Table 8, neither FGR nor SCR are cost-effective NO_x control options.

ACHD considers the Boiler No. 4 meeting their existing permit conditions and regulatory requirements to be RACT.

Review of the RBLC indicates that the current emission limit for Boiler No. 4 (0.038 lb/MMBtu) is consistent with performance of other natural gas fired boilers with a capacity less than 50 MMBtu/hr and operating with LNB. Boilers with this configuration are limited to between 0.0109 and 0.070 and an average of 0.038 lb/MMBtu. Table 9 provides the RBLC findings.

Table 9. EPA's RBLC Findings

Source	RBLC ID	Date of Permit Issuance	NO _x Limit (lb/MMBtu)	NO _x Control
13.31 – Gas Chouteau Power Plant [33.5 MMBtu/hr]	OK-0129	1/23/2009	0.0700	LNB
11.31 – Gas Harrah'S Operating Company, Inc. [16.7 MMBtu/hr]	NV-0049	8/20/2009	0.0490	LNB
13.31 – Gas Harrah'S Operating Company, Inc. [33.48 MMBtu/hr]	NV-0049	8/20/2009	0.0367	LNB
12.31 – Gas Harrah'S Operating Company, Inc. [21 MMBtu/hr]	NV-0049	8/20/2009	0.0366	LNB
13.31 – Gas Ray Compressor Station [12.25 MMBtu/hr]	*MI-0393	10/14/2010	0.0350	LNB
13.31 – Gas Harrah'S Operating Company, Inc. [35.4 MMBtu/hr]	NV-0049	8/20/2009	0.0350	LNB
13.31 – Gas Harrah'S Operating Company, Inc. [31.38 MMBtu/hr]	NV-0049	8/20/2009	0.0306	LNB
13.31 – Gas Harrah'S Operating Company, Inc. [24 MMBtu/hr]	NV-0049	8/20/2009	0.0108	LNB
13.31 – Gas Suwannee Mill [46 MMBtu/hr]	FL-0335	9/5/2012	0.0360	LNB+FGR
13.31 – Gas Harrah'S Operating Company, Inc. [14.34 MMBtu/hr]	NV-0049	8/20/2009	0.0353	LNB+FGR
13.31 – Gas Harrah'S Operating Company, Inc. [16.8 MMBtu/hr]	NV-0049	8/20/2009	0.0300	LNB+FGR
11.31 – Gas Mgm Mirage [41.64 MMBtu/hr]	NV-0050	11/30/2009	0.0110	LNB+FGR
12.31 – Gas Mgm Mirage [44 MMBtu/hr]	NV-0050	11/30/2009	0.0109	LNB+GCP
11.31 – Gas Montville Power LLC [995 MMBtu/hr]	CT-0156	4/6/2010	0.0600	SCR
13.31 – Gas Kenai Nitrogen Operations [50 MMBtu/hr]	*AK-0083	1/6/2015	0.0084 (3 hr avg. @15% O ₂)	SCR

Source	RBLC ID	Date of Permit Issuance	NO _x Limit (lb/MMBtu)	NO _x Control
Current Operating Permit Limit	-	2009	0.038	LNB

**REASONABLY ACHIEVABLE CONTROL TECHNOLOGY (RACT)
ANALYSIS**

**ENERGY CENTER PITTSBURGH LLC
NORTH SHORE PLANT**

Prepared For:

**ALLEGHENY COUNTY HEALTH DEPARTMENT
301 39TH STREET, BUILDING 7
PITTSBURGH, PENNSYLVANIA 15201**

Submitted By:

**ENERGY CENTER PITTSBURGH LLC – NORTH SHORE PLANT
111 SOUTH COMMONS
PITTSBURGH, PENNSYLVANIA 15212**

Prepared By:

**CIVIL & ENVIRONMENTAL CONSULTANTS, INC.
MONROEVILLE, PENNSYLVANIA**

CEC Project 195-822

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Civil & Environmental Consultants, Inc.

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1.0 INTRODUCTION

1.1 BACKGROUND AND PURPOSE

Reasonably Achievable Control Technology (RACT) is defined by the U.S. Environmental Protection Agency (EPA) 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.” The Federal Clean Air Act (CAA) requires a re-evaluation of RACT requirements each time the EPA promulgates a National Ambient Air Quality Standard (NAAQS). Because the ozone NAAQS was revised in 2008, a re-evaluation of RACT was necessary. RACT requirements apply statewide to the owner or operator of a major nitrogen oxides (NO_x) emitting facility, a major volatile organic compound (VOC) emitting facility, or both, when the installation/modification of the source(s) occurred before July 20, 2012. NO_x and VOC are pre-cursors to the formation of ozone.

As such, the Pennsylvania Department of Environmental Protection (PADEP) implemented regulations entitled, “Additional RACT Requirements for Major Sources of NO_x and VOCs” (known as RACT II), which were promulgated by the Environmental Quality Board on April 23, 2016 (46 Pa.B. 2036). This regulation is referred to as RACT II, as the first round of RACT was implemented by PADEP in 1995. An owner or operator of a major NO_x or a VOC emitting facility as defined in 25 Pa. Code §121.1 was to demonstrate compliance with the RACT II requirements by January 1, 2017.

An owner or operator subject to RACT II has three compliance options as follows:

- 1) Compliance with presumptive RACT requirements and/emissions limits;
- 2) Facility-wide or system-wide averaging for compliance with presumptive NO_x emissions limits; or
- 3) Case-by-case RACT determinations for sources that either do not have an applicable presumptive requirements or emissions limitation or cannot comply with the applicable presumptive RACT requirement.

Energy Center Pittsburgh’s (ECP) North Shore Plant (North Shore) is located in Allegheny County, Pennsylvania and is classified as a major source of NO_x. Section 2105.06 of Allegheny County Health Department (ACHD) Rules and Regulations, Article XXI Air Pollution Control requires that RACT be applied to all major sources of NO_x. ECP submitted a timely RACT II Rule Compliance Plan to ACHD for North Shore in April 2016, with a revision submitted on November 10, 2016. In the submitted RACT II Rule Compliance Plan, ECP proposed complying with the presumptive RACT for North Shore’s three emergency generators (P001) and Boilers 4 and 5 (B004 and B005) and submitted a case-by-case RACT proposal for Boilers 1, 2, and 3 (B001, B002, and B003).

On October 18, 2019, ACHD issued a review letter with comments on the case-by-case RACT proposal for Boilers 1, 2 and 3. In the letter, ACHD identified specific points in the previous RACT Analysis that ACHD found in error or unwarranted. This revised RACT Analysis has been prepared to address ACHD’s comments.

1.2 FACILITY DESCRIPTION

North Shore is a commercial district heating and cooling plant located at 111 South Commons in the North Shore section of Pittsburgh, PA. The plant supplies steam for space heating and hospital sterilization and chilled water for summer air conditioning to commercial and institutional sites in that area.

The plant is composed of five (5) boilers, which fire natural gas as their primary fuel and have the capacity to fire no. 2 fuel oil, in lieu of natural gas at times of emergency or natural gas curtailment with the exception of Boilers 4 and 5. Additional equipment used for chilled water production includes various turbines, chillers, compressors and cooling towers. The facility is a major source of NO_x and carbon monoxide (CO) and minor source of particulate matter (PM), particulate matter < 10 microns in diameter (PM-10), sulfur dioxide (SO₂), VOCs and hazardous air pollutants (HAPs) as defined in section 2101.20 of Article XXI.

1.3 RACT AFFECTED UNITS

As described in the RACT II Rule Compliance Plan submitted in 2016, the following table (Table 1-1) illustrates the sources at North Shore subject to RACT II and the method used for demonstrating compliance with the RACT II requirements.

Table 1-1: Description of RACT Affected Units

Source ID	Source Description	Capacity	Install Year	Fuel	RACT II Compliance Method
P001	Three Emergency Generators	350 kW; 250 kW & 250 kW	2004, 1999, 1972	No. 2 fuel oil; Natural gas	Presumptive RACT requirement per §129.97(c) for emergency engines operating less than 500 hours per year– installation, maintenance and operation in accordance with manufacturer’s specifications and good operating practices
B001	Babcock & Wilcox forced draft, water tube boiler	92 MMBtu/hr	1967	Natural gas; No. 2 fuel oil (emergency backup)	Case-by-case RACT – does not meet presumptive RACT emission limit of 0.10 lb NO _x /MMBtu for natural gas-fired combustion unit with a rated heat input ≥ 50 MMBtu/hr
B002	Babcock & Wilcox forced draft, water tube boiler	92 MMBtu/hr	1967	Natural gas; No. 2 fuel oil (emergency backup)	Case-by-case RACT – does not meet presumptive RACT emission limit of 0.10 lb NO _x /MMBtu for natural gas-fired combustion unit with a rated heat input ≥ 50 MMBtu/hr
B003	Babcock & Wilcox forced draft, water tube boiler	131.1 MMBtu/hr	1971	Natural gas; No. 2 fuel oil (emergency backup)	Case-by-case RACT – does not meet presumptive RACT emission limit of 0.10 lb NO _x /MMBtu for natural gas-fired combustion unit with a rated heat input ≥ 50 MMBtu/hr
B004	Unilux forced draft, water tube boiler (with low-NO _x burners)	24 MMBtu/hr	2001	Natural gas	Presumptive RACT requirement per §129.97(b)(2) for combustion units with a rated heat input ≥ 20 MMBtu/hr and ≤ 50 MMBtu/hr with an oxygen trim system that maintains an optimum air-to-fuel ratio - conduct a tune-up of the boiler one time in each 5-year calendar period.
B005	Nebraska Boiler	46.08 MMBtu/hr	2008	Natural gas	Presumptive RACT requirement per §129.97(c) for fuel-burning unit with an annual capacity factor of < 5% – installation, maintenance and operation in accordance with manufacturer’s specifications and good operating practices

Boilers 1, 2 and 3 are capable of being fired with either natural gas (primary fuel) or No. 2 fuel oil as emergency / back-up fuel. Because No. 2 fuel oil will only be used in the event of an emergency, No. 2 fuel oil control technology was not evaluated for the boilers as a part of this analysis. NOx emissions from these boilers are determined by performance of a periodic compliance emissions test program. The most recent compliance test program was conducted in November 2017. The results from the test program, as compared to the presumptive RACT emission limits are summarized in the following table (Table 1-2).

Table 1-2: Boilers 1, 2 and 3 NOx Emission Rates

Source ID	NOx Emission Rates – Natural Gas Firing (lb/MMBtu)		
	2017 Stack Test Results	Title V Permit Limit	Presumptive RACT Limit
Boiler 1	0.121	0.145	0.10
Boiler 2	0.140	0.145	0.10
Boiler 3	0.107	0.145	0.10

Because these test results demonstrate that Boilers 1, 2 and 3 cannot meet the applicable presumptive RACT emission limitation, ECP has elected to demonstrate compliance using a case-by-case RACT. The case-by-case RACT analysis and proposal for Boilers 1, 2 and 3 is detailed in the following sections.

2.0 RACT ANALYSIS FOR BOILERS 1, 2 AND 3

2.1 RACT METHODOLOGY

As discussed in the previously submitted RACT II submittals and in Section 1.3, Boilers 1, 2 and 3 at North Shore do not meet the presumptive RACT NO_x emission limit of 0.10 lb NO_x/MMBtu for natural gas-fired combustion unit with a rated heat input greater than or equal to 50 MMBtu/hr. For sources that cannot comply with a presumptive RACT requirement and/or emissions limit, a case-by-case RACT II proposal must be developed in accordance with 25 Pa. Code §129.99(d); therefore, ECP is submitting a case-by-case RACT proposal for North Shore Boilers 1, 2 and 3. The RACT proposal must include the following information:

- A list of each air contamination source included in the RACT proposal (see Section 1.3, Table 1-1);
- The size or capacity of each affected source and the types of fuel combusted, or the types and quantities of materials processed or produced in each source (see Section 1.3, Table 1-1);
- A physical description of each source and its operating characteristics (see Section 1.3, Table 1-1);
- Estimates of the potential and actual NO_x emissions from each affected source, and associated supporting documentation;
- The actual proposed alternative NO_x RACT requirement or NO_x RACT emissions limitation;
- A RACT analysis which meets the requirements of §129.92(b), including technical and economic support documentation for each affected source;
- A schedule for completing implementation of the RACT requirement or RACT emissions limitation;
- The intended testing, monitoring, recordkeeping, and reporting procedures proposed to demonstrate compliance with the proposed RACT requirement(s) and/or limitation(s); and,
- Additional information requested by the ACHD that is necessary for the evaluation of the RACT proposal.

Pursuant to 25 Pa. Code §129.92(b), the RACT analysis consists of a five-step, top-down, control technology feasibility analysis.

The first step in this approach is to determine, for the emission unit in question, the most stringent control available for a similar or identical source or source category for each regulated pollutant subject to review. If it can be shown this level of control is not technically or economically feasible, the next most stringent level of control is then determined and similarly evaluated. This process continues until a control technology and associated emission level is determined that cannot be eliminated by any technical, environmental, or economic objections. The five steps involved in a top down RACT analysis process are listed below:

- Step 1 Identify all available control technologies for the source.
- Step 2 Eliminate technically infeasible or commercially unavailable technology options.
- Step 3 Rank the remaining control technologies by control effectiveness.
- Step 4 Evaluate the most effective controls considering energy, environmental, economic, and other costs and document the results. If the top option is not selected as RACT, evaluate the next most effective control option.
- Step 5 Select RACT.

2.2 DESCRIPTION OF BASELINE CONDITIONS AND EMISSIONS

Boilers 1, 2, and 3 are located in the main boiler plant located at 111 South Commons and are conventional package boilers. These boilers provide steam to a district energy system; customers connected to the system use the steam primarily for space heating. Summer operation of the boilers is required to operate steam driven chillers, which provide chilled water for cooling at customer locations. Boiler loads are relatively higher in the heating season.

NOx emission rates from these boilers are determined by performance of a periodic compliance emissions test program. According to the facility's Title V Operating Permit, ECP must perform NOx emission testing on Boilers 1, 2 and 3 every two (2) years. Annual NOx emissions are calculated using the emission rates determined from the most recent stack tests and the fuel use for each boiler. These emissions are reported to the ACHD in the facility's annual emission inventory report.

In addition, the boilers are subject to NOx emission limitations as specified in the facility's Title V Operating Permit. The permitted emission limitations are based on potential to emit calculations, assuming that the boilers run 8,760 hours per year at full rated capacity.

Per Section 129.92(b)(4)(iii), the baseline emissions rate shall be established using either test results or approved emission factors and historic operating data. The baseline NOx emission rates (lbs/MMBtu) used in this analysis are the results from the most recent stack test performed on November 9, 2017.

As part of the RACT proposal as presented in Section 3, ECP is proposing to restrict natural gas consumed in Boiler 1 by 50 percent (%), Boiler 2 by 35% and Boiler 3 by 5% of the maximum boiler capacity. In order to annualize the baseline emissions rate, annual emissions were calculated using the proposed natural gas fuel limit. A summary of previously reported (Reporting Years 2017 and 2018) actual emissions and fuel usage and baseline emissions are summarized in the following table (Table 2-1).

Table 2-1: Boilers 1, 2 and 3 Annual Fuel Usage and NOx Emissions

Source ID	Capacity (MMBtu/hr)	Actual Emission Rate (lb/MMBtu)*	Fuel Usage (MMScf/Year)				Annual Emissions (TPY)			
			Permit Limit	2017 Actual	2018 Actual	Proposed Fuel Limit	Permit Limit	2017 Actual	2018 Actual	Baseline
Boiler 1	92	0.121	790	32	148	395	54.2	2.0	9.0	24.4
Boiler 2	92	0.140	790	132	267	514	54.2	9.4	18.9	36.7
Boiler 3	131.1	0.107	1,125	395	256	1,069	77.3	21.4	13.9	58.3

*Emission rates from stack test performed on November 9, 2017

2.3 BACKGROUND ON POLLUTANT FORMATION

NOx formation in combustion processes is generally believed to be the result of three different mechanisms producing “prompt NOx,” “thermal NOx,” and “fuel NOx.” Prompt NOx is the result of intermediate combustion reactions involving nitrogen (N₂), oxygen (O₂) and hydrocarbons (C_xH_y). Thermal NOx is the result of N₂ and O₂ reactions occurring at high temperatures during the combustion process. Fuel NOx results from the oxidation of nitrogen compounds in the fuel itself.

Prompt NOx and thermal NOx reactions are temperature driven, with prompt NOx being the dominant mechanism at low temperatures and thermal NOx formation dominating at higher temperatures. Industrial combustion processes occur at relatively high temperatures thus making thermal NOx the more significant contributor under typical boiler operating conditions. U.S. EPA notes the “principal mechanism of NOx formation in natural gas combustion is thermal NOx” (see AP-42, §1.4.3). For purposes of this analysis, when natural gas is burned, it will be assumed that 100% of the NOx is the result of thermal NOx formation. Fuel NOx is nominally a function of fuel-bound nitrogen concentration, thus making it a less important reaction when low nitrogen fuels such as natural gas and No. 2 fuel oil are used.

2.4 IDENTIFICATION OF POTENTIAL CONTROL TECHNIQUES (STEP 1)

Boiler NOx control technologies are generally divided into combustion or post-combustion controls. Commonly applied combustion controls for industrial boilers are most effective at preventing the formation of thermal NOx by limiting peak flame temperatures; these technologies are not effective at preventing fuel NOx. Post-combustion controls can effectively reduce both thermal and fuel NOx because these controls are designed to remove NOx which is already present in the flue gases exiting the furnace.

A review of the literature on NOx control and consultation with boiler equipment vendors has identified several possible control technologies that could be applied to boilers similar to those installed at ECP. The descriptions in the following sections of this analysis have been taken from the “Boiler Emission Guide” published by Cleaver Brooks.

2.4.1 Combustion Control Techniques

“Combustion control techniques reduce the amount of NO_x emission by limiting the amount of NO_x formation during the combustion process. This is typically accomplished by lowering flame temperatures. Combustion control techniques are more economical than post-combustion methods and are frequently utilized on industrial boilers requiring NO_x controls.”

- Low excess air firing – “As a safety factor to assure complete combustion, boilers are fired with excess air. One of the factors influencing NO_x formation in a boiler is the excess air levels. High excess air levels (greater than 45 percent) may result in increased NO_x formation because the excess nitrogen and oxygen in the combustion air entering the flame will combine to form thermal NO_x. Low excess air firing involves limiting the amount of excess air that is entering the combustion process in order to limit the amount of extra nitrogen and oxygen that enters the flame. Limiting the amount of excess air entering a flame is usually accomplished through burner design and can be optimized through the use of oxygen trim controls.”
- Burner modifications – “Burner modifications for NO_x control involve changing the design of a standard burner in order to create a larger flame. Enlarging the flame results in lower flame temperatures and lower thermal NO_x formation which, in turn, results in lower overall NO_x emissions. The technology can be applied to most boiler types and sizes. It is most effective when firing natural gas and distillate fuel oil and has little effect on boilers firing heavy oil. To comply with the more stringent regulations, burner modifications must be used in conjunction with other NO_x reduction methods, such as flue gas recirculation. If burner modifications are utilized exclusively to achieve low NO_x levels, adverse effects on boiler operating parameters such as turndown, capacity, CO levels and efficiency may result.”
- Water/Steam Injection – “Water or steam injection can be utilized to reduce NO_x levels. By introducing water or steam into the flame, flame temperatures are reduced, thereby lowering thermal NO_x formation and overall NO_x levels. Water or steam injection can reduce NO_x up to 80 percent (when firing natural gas) and can result in lower reductions when firing oils. There is a practical limit to the amount of water or steam that can be injected into the flame before condensation problems are experienced. Additionally, under normal operating conditions, water/steam injection can result in a 3 to 10 percent efficiency loss. Many times water or steam injection is used in conjunction with other NO_x control methods such as burner modifications or flue gas recirculation.”
- Flue Gas Recirculation – “Flue gas recirculation, or FGR, is the most effective method of reducing NO_x emissions from industrial boilers with inputs below 100 MMBtu/hr. FGR entails recirculating a portion of relatively cool exhaust gases back into the combustion zone in order to lower the flame temperature and reduce NO_x formation. It is currently the most effective and popular low NO_x technology for firetube and watertube boilers. And, in many applications, it does not require any additional reduction equipment to comply with the most stringent regulations in the United States.

Flue gas recirculation technology can be classified into two types; external or induced. External flue gas recirculation utilizes an external fan to recirculate the flue gases back into the combustion zone. External piping routes the exhaust gases from the stack to the burner. A valve controls the recirculation rate, based on boiler input. Induced flue gas recirculation utilizes the combustion air fan to recirculate the flue gases back into the combustion zone. A portion of the flue gases are routed by duct work or internally to the combustion air fan, where they are premixed with the combustion air and introduced into the flame through the burner. New designs of induced FGR that utilize an integral FGR design are becoming popular among boiler owners and operators because of their uncomplicated design and reliability.

Theoretically, there is no limit to the amount of NO_x reduction with FGR; practically, there is a physical, feasible limit. The limit of NO_x reduction varies for different fuels – 90 percent for natural gas and 25 to 30 percent for standard fuel oils. The current trends with low NO_x technologies are to design the boiler and low NO_x equipment as a package. Designing as a true package allows the NO_x control technology to be specifically tailored to match the boiler's furnace design features, such as shape, volume, and heat release. By designing the low NO_x technology as a package with the boiler, the effects of the low NO_x technology on boiler operating parameters (turndown, capacity, efficiency, and CO levels) can be addressed and minimized."

2.4.2 Post Combustion Control Methods

- Selective Non-Catalytic Reduction – "Selective non-catalytic reduction involves the injection of a NO_x reducing agent, such as ammonia or urea, in the boiler exhaust gases at a temperature of approximately 1,400 to 1,600 degrees Fahrenheit. The ammonia or urea breaks down the NO_x in the exhaust gases into water and atmospheric nitrogen. Selective non-catalytic reduction reduces NO_x up to 50 percent. However, the technology is extremely difficult to apply to industrial boilers that modulate frequently. This is because the ammonia (or urea) must be injected in the flue gases at a specific flue gas temperature. And in industrial boilers that modulate frequently, the location of the exhaust gases at the specified temperature is constantly changing. Thus, it is not feasible to apply selective non-catalytic reduction to industrial boilers that have high turndown capabilities and modulate frequently."
- Selective Catalytic Reduction – "Selective catalytic reduction involves the injection of ammonia in the boiler exhaust gases in the presence of a catalyst. The catalyst allows the ammonia to reduce NO_x levels at lower exhaust temperatures than selective non-catalytic reduction. Unlike selective non-catalytic reduction, where the exhaust gases must be approximately 1,400 to 1,600 degrees Fahrenheit, selective catalytic reduction can be utilized where exhaust gases are between 500 and 1,200 degrees Fahrenheit, depending on the catalyst used. Selective catalytic reduction can result in NO_x reductions up to 90 percent. However, it is costly to use and rarely can be cost justified on boilers with inputs less than 100 MMBtu/hour."

2.5 ELIMINATION OF TECHNICALLY INFEASIBLE CONTROL OPTIONS (STEP 2)

In this step, the control technologies identified in Step 1 are considered, and those which are clearly technically infeasible or have not been demonstrated (i.e., unavailable) are eliminated.

- Selective Catalytic Reduction – Although the technology can achieve very high levels of NO_x control, the expected flue gas temperatures for Boilers 1, 2 and 3 are typically below the effective range required for the application of SCR controls. This control is being eliminated from further consideration on the basis that it is not technically feasible.
- Flue Gas Recirculation – FGR is a commonly applied technology which has been widely applied to industrial boilers, although the operating costs increase with recirculation rates as the increased flows require more energy to operate recirculation fans. This technology will be included for further analysis as it is widely applied on similar emission units and therefore considered feasible. The technology is an effective thermal NO_x control.
- Selective Non-Catalytic Reduction – The narrative description presented above identifies problems with applying this technology to industrial boilers. Boilers that cycle and modulate, such as those used in heating applications, make it difficult to locate the necessary temperature zone for ammonia injection. This technology is being eliminated from further analysis for reasons stated previously in this narrative.
- Burner Modifications – Low NO_x burners (LNB) and Ultra-Low NO_x burners (ULNB) have been widely used in natural gas-fired boiler applications. The most effective control results when combining LNB/ULNB technology with other techniques such as FGR. The technology has been demonstrated to significantly reduce thermal NO_x formation but is not expected to have a significant impact on fuel NO_x formation.
- Low Excess Air Firing – The modest levels of reduction coupled with the already relatively low NO_x levels permitted at North Shore make it unlikely that this technology would yield cost-effective benefits. An oxygen trim system that is designed to maintain an optimum air-to-fuel ratio is currently installed and operated on Boilers 1, 2 and 3. This technology will not be subject to additional review due to the very modest levels of control achievable; control of fuel NO_x would be negligible.
- Water/Steam Injection – NO_x control can be extremely effective but high rates of injection adversely impact boiler efficiency thus limiting the practical use of this technology to achieve high levels of control. Because of the potential adverse impacts on boiler performance, and the availability of other technologies capable of similar or better levels of control, this technology will not be included for further analysis.

Based on the evaluations presented above, boiler vendor recommendations and a request from the ACHD, ECP has selected FGR and burner modification (LNB and ULNB) for further evaluation.

2.6 RANKING OF REMAINING CONTROL OPTIONS (STEP 3)

A ranking of the technically feasible control options in order of overall control effectiveness for NO_x emissions is presented below. The following five NO_x emissions control options were considered (listed in increasing order of control effectiveness):

- Control Option No. 1 – New LNB
- Control Option No. 2 – Re-use existing burner, re-use existing forced draft (FD) fan but install FGR. The amount of FGR would be limited by fan capacity.
- Control Option No. 3 - Add FGR and replace FD fan to allow greater percentage of FGR
- Control Option No. 4 - New LNB burner, new FD fan, FGR
- Control Option No. 5 - New ULNB, new FD fan, FGR, damper/drive replacement. Please note per the boiler vendor, while Option 5 is a possible retrofit for the existing boilers, Options 2, 3 or 4 are a more common option. ULNB are very tightly controlled, are more susceptible to any upsets in the process and would bring more risk of success considering the age of the existing equipment.

2.7 EVALUATION OF MOST STRINGENT CONTROLS (STEP 4)

After ranking the technically feasible control technologies, the fourth step of the analysis is to evaluate the control options on the basis of economic, energy, and environmental considerations, and document the results. An evaluation of cost effectiveness of each control option consistent with the “OAQPS Control Cost Manual” (Sixth Edition), EPA 450/3-90-006 and subsequent revisions is presented Appendix A, which includes the following tables:

- Table 1 – Capital Cost Estimates
- Table 2 – Annualized Cost Estimates
- Table 3 – Cost-Effectiveness Estimates

Vendor data used in the cost analysis is included in Appendix B.

2.8 SELECTION OF RACT (STEP 5)

The presumptive RACT benchmark is \$2,800/ton NO_x. The RACT II preamble notes that a 25% buffer to the cost-effectiveness will not change the presumptive RACT determination. This buffer increases the presumptive RACT benchmark to \$3,500/ton NO_x. Based on this benchmark and because the average cost effectiveness values for all options evaluated are in excess of \$8,000/ton NO_x removed, ECP submits that the five evaluated control options are cost prohibitive. ECP requests approval of the RACT proposal detailed in Section 3.

3.0 RACT PROPOSAL

Based on the technology screening analysis and economic analysis completed, there are no source control or add-on NOx control technologies that are technologically feasible and cost effective for Boilers 1, 2 and 3. ECP is proposing to comply with RACT II for Boilers 1, 2 and 3 with a case-by-case RACT proposal. The proposed RACT requirements are as follows:

3.1 WORK PRACTICES

The facility will operate Boilers 1, 2 and 3 in accordance with good engineering practices.

3.2 RESTRICTIONS

The facility will operate in accordance with a Title V Operating Permit that restricts NOx emissions and natural gas fuel usage to the following permit limits:

Table 3-1: Boilers 1, 2 and 3 Title V Operating Permit Restrictions

Source ID	NOx Emission Limitation		Natural Gas Usage Limit (MMScf/Year)
	lb/MMBtu	TPY	
Boiler 1	0.145	54.2	395
Boiler 2	0.145	54.2	514
Boiler 3	0.145	77.3	1,069

NOx emission limitations will remain consistent with the current Title V Operating Permit emission restrictions per Conditions V.B.1.c and V.C.1c. The proposed natural gas usage restrictions will be incorporated into the Title V Operating Permit through a permit modification.

3.3 TESTING REQUIREMENTS

The facility will follow the testing requirements as listed in Sections V.B.2 and V.C.2 of the Title V Operating Permit.

3.4 MONITORING, RECORDKEEPING AND REPORTING REQUIREMENTS

ECP will continue to comply with the monitoring, recordkeeping and reporting requirements in accordance with the facility's existing Title V Operating Permit, as follows:

Conditions V.B.4 and 5 (Boilers 1 and 2) and V.C.4 and 5 (Boiler 3)

- (1) Records of fuel consumption (daily, monthly, rolling 12-month recording basis)
- (2) Records of operating hours (daily, monthly, rolling 12-month recording basis)
- (3) Reports of fuel consumption (monthly and rolling 12-month totals)
- (4) Reports of operating hours (monthly and rolling 12-month totals)

APPENDIX A

RACIAL ECONOMIC ANALYSIS

Energy Center Pittsburgh
PA DEP RACT II Rule - Case-by-Case NOx RACT Proposal for Boilers 1 and 2
Table 1 - Capital Cost Estimates

Cost Item	Computation Method	Factor	Costs for Each NOx Control Option					Notes
			Option 1	Option 2	Option 3	Option 4	Option 5	
Direct Costs								
Purchased Equipment (PE)	Vendor Quote x factor	1	\$182,938	\$119,742	\$194,026	\$376,964	\$526,964	Input - B&W 2019 Vendor Quote OAQPS Control Cost Manual, Table 2.4 (Nov 2017)
Freight	PE x factor	0.05	<u>\$9,147</u>	<u>\$5,987</u>	<u>\$9,701</u>	<u>\$18,848</u>	<u>\$26,348.20</u>	
Total Purchased Equipment Costs (PEC)	Sum		\$192,085	\$125,729	\$203,727	\$395,812	\$553,312	
Installation Costs	Vendor Quote	1	\$110,872	\$160,764	\$232,831	\$395,812	\$435,394	Input - B&W 2019 Vendor Quote
Total Direct Costs (TDC)	Sum PEC + Installation Costs	1	\$302,957	\$286,493	\$436,558	\$791,624	\$988,706	
Installation Costs, Indirect								
Engineering / supervision	TDC x factor	0.10	\$30,296	\$28,649	\$43,656	\$79,162	\$98,871	OAQPS Control Cost Manual, Table 2.4 (Nov 2017)
Construction / field expenses	TDC x factor	0.10	\$30,296	\$28,649	\$43,656	\$79,162	\$98,871	OAQPS Control Cost Manual, Table 2.4 (Nov 2017)
Construction fee	TDC x factor	0.10	\$30,296	\$28,649	\$43,656	\$79,162	\$98,871	OAQPS Control Cost Manual, Table 2.4 (Nov 2017)
Start-up	TDC x factor	0.01	\$3,030	\$2,865	\$4,366	\$7,916	\$9,887.06	OAQPS Control Cost Manual, Table 2.4 (Nov 2017)
Performance test	TDC x factor		\$12,000	\$12,000	\$12,000	\$12,000	\$12,000	Plant Estimate based on current test costs
Model Study	TDC x factor	0	\$0	\$0	\$0	\$0	\$0	OAQPS Control Cost Manual, Table 2.4 (Nov 2017)
Contingencies	TDC x factor	0.2	<u>\$60,591</u>	<u>\$57,299</u>	<u>\$87,312</u>	<u>\$158,325</u>	<u>\$197,741.24</u>	Vendor quote pricing is +/- 20%
Total Indirect Costs (TIC)	Sum	0.51	\$166,508	\$158,111	\$234,645	\$415,728	\$516,240	
Total Capital Investment (TCI)	Sum TDC + TIC	1	\$469,465	\$444,605	\$671,203	\$1,207,353	\$1,504,946	

- Notes:
- The Capital Cost Estimates were prepared using the methods described in the OAQPS Control Cost Manual 6th Edition and updated chapters.
 - The NOx control options include the following:
NOx Control Option 1: New Low-NOx burner.
NOx Control Option 2: Re-use existing burner, re-use existing forced draft (FD) fan but install flue gas recirculation(FGR). The amount of FGR would be limited by fan capacity.
NOx Control Option 3: Add FGR and replace FD fan to allow greater % of flue gas recirculation.
NOx Control Option 4: New Low-NOx burner, new FD fan, flue gas recirculation.
NOx Control Option 5: New Ultra-Low-NOx burner, new FD fan, flue gas recirculation, damper/drive replacements.
 - The purchased equipment costs and direct installation costs were provided by the vendor.
 - The factors used to determine the freight cost and indirect installation costs (except contingency) were referenced from the OAQPS Control Cost Manual, Table 2.4 (Nov 2017).
 - The factor used to determine the indirect installation cost for contingency was provided by the vendor.
 - The costs are the same for Boilers 1 and 2.

Energy Center Pittsburgh
PA DEP RACT II Rule - Case-by-Case NOx RACT Proposal for Boiler 3
Table 1 - Capital Cost Estimates

Cost Item	Computation Method	Factor	Costs for Each NOx Control Option					Notes
			Option 1	Option 2	Option 3	Option 4	Option 5	
Direct Costs								
Purchased Equipment (PE)	Vendor Quote x factor	1	\$194,026	\$119,742	\$210,656	\$404,682	\$554,682	Input - B&W 2019 Vendor Quote OAQPS Control Cost Manual, Table 2.4 (Nov 2017)
Freight	PE x factor	0.05	<u>\$9,701</u>	<u>\$5,987</u>	<u>\$10,533</u>	<u>\$20,234</u>	<u>\$27,734.10</u>	
Total Purchased Equipment Costs (PEC)	Sum		\$203,727	\$125,729	\$221,189	\$424,916	\$582,416	
Installation Costs	Vendor Quote	1	\$110,872	\$160,764	\$252,788	\$426,856	\$469,542	Input - B&W 2019 Vendor Quote
Total Direct Costs (TDC)	Sum PEC + Installation Costs	1	\$314,599	\$286,493	\$473,977	\$851,772	\$1,051,958	
Installation Costs, Indirect								
Engineering / supervision	TDC x factor	0.10	\$31,460	\$28,649	\$47,398	\$85,177	\$105,196	OAQPS Control Cost Manual, Table 2.4 (Nov 2017)
Construction / field expenses	TDC x factor	0.10	\$31,460	\$28,649	\$47,398	\$85,177	\$105,196	OAQPS Control Cost Manual, Table 2.4 (Nov 2017)
Construction fee	TDC x factor	0.10	\$31,460	\$28,649	\$47,398	\$85,177	\$105,196	OAQPS Control Cost Manual, Table 2.4 (Nov 2017)
Start-up	TDC x factor	0.01	\$3,146	\$2,865	\$4,740	\$8,518	\$10,520	OAQPS Control Cost Manual, Table 2.4 (Nov 2017)
Performance test	TDC x factor		\$12,000	\$12,000	\$12,000	\$12,000	\$12,000	Plant Estimate based on current test costs
Model Study	TDC x factor	0	\$0	\$0	\$0	\$0	\$0	OAQPS Control Cost Manual, Table 2.4 (Nov 2017)
Contingencies	TDC x factor	0.2	<u>\$62,920</u>	<u>\$57,299</u>	<u>\$94,795</u>	<u>\$170,354</u>	<u>\$210,391.62</u>	Vendor quote pricing is +/- 20%
Total Indirect Costs (TIC)	Sum	0.51	\$172,446	\$158,111	\$253,728	\$446,404	\$548,499	
Total Capital Investment (TCI)	Sum TDC + TIC	1	\$487,045	\$444,605	\$727,705	\$1,298,176	\$1,600,457	

- Notes:
- The Capital Cost Estimates were prepared using the methods described in the OAQPS Control Cost Manual 6th Edition and updated chapters.
 - The NOx control options include the following:
NOx Control Option 1: New Low-NOx burner.
NOx Control Option 2: Re-use existing burner, re-use existing forced draft (FD) fan but install flue gas recirculation(FGR). The amount of FGR would be limited by fan capacity.
NOx Control Option 3: Add FGR and replace FD fan to allow greater % of flue gas recirculation.
NOx Control Option 4: New Low-NOx burner, new FD fan, flue gas recirculation.
NOx Control Option 5: New Ultra-Low-NOx burner, new FD fan, flue gas recirculation, damper/drive replacements.
 - The purchased equipment costs and direct installation costs were provided by the vendor.
 - The factors used to determine the freight cost and indirect installation costs (except contingency) were referenced from the OAQPS Control Cost Manual, Table 2.4 (Nov 2017).
 - The factor used to determine the indirect installation cost for contingency was provided by the vendor.

Energy Center Pittsburgh
PA DEP RACT II Rule - Case-by-Case NOx RACT Proposal for Boiler 1
Table 2 - Annualized Cost Estimates

Cost Item	Computation Method	Factor	Costs for Each NOx Control Option					Notes
			Option 1	Option 2	Option 3	Option 4	Option 5	
<u>Direct Operating Costs</u>								
Operating Labor - Operator (OL)	(0.5 man-hours / shift) x (equivalent shifts / yr) x factor	65.00	\$4,063	\$4,063	\$4,063	\$4,063	\$4,063	OAQPS Control Cost Manual; factor = typical loaded labor rate (\$/hr)
Operating Labor - Supervision	OL x factor	0.15	\$609.38	\$609	\$609	\$609	\$609	OAQPS Control Cost Manual
Maintenance Labor (ML)	(0.5 man-hours / shift) x (equivalent shifts / yr) x factor	65.00	\$4,063	\$4,063	\$4,063	\$4,063	\$4,063	OAQPS Control Cost Manual; factor = typical loaded labor rate (\$/hr)
Maintenance Materials	100% of ML	1	\$4,063	\$4,063	\$4,063	\$4,063	\$4,063	OAQPS Control Cost Manual
<u>Utilities - Electricity</u>								
Additional Fan Power	Calculation - see below	1						OAQPS Control Cost Manual (Equation 2.10);
KWh	KWh x factor	0.11	<u>\$0</u>	<u>\$986</u>	<u>\$3,566</u>	<u>\$3,566</u>	<u>\$3,566</u>	factor = typical electricity cost (\$/KWh)
Total Direct Operating Costs (DOC)	Sum		\$12,797	\$13,783	\$16,363	\$16,363	\$16,363	
<u>Indirect Operating Costs</u>								
Overhead	(OL + ML) x factor	0.60	\$4,875	\$4,875	\$4,875	\$4,875	\$4,875	OAQPS Control Cost Manual (Section 2.6.5.7)
Insurance	TCI x factor	0.01	\$4,695	\$4,446	\$6,712	\$12,074	\$15,049	OAQPS Control Cost Manual
Administration	TCI x factor	0.02	\$9,389	\$8,892	\$13,424	\$24,147	\$30,099	OAQPS Control Cost Manual
Capital Recovery	TCI x factor	0.10979	<u>\$51,543</u>	<u>\$48,813</u>	<u>\$73,691</u>	<u>\$132,555</u>	<u>\$165,228</u>	Factor per OAQPS Control Cost Manual (Equation 2.8)
Total Indirect Operating Costs (IOC)	Sum		\$70,502	\$67,026	\$98,702	\$173,651	\$215,251	
Total Annualized Cost (TAC)	Sum DOC+ IOC	1	\$83,298	\$80,809	\$115,065	\$190,014	\$231,614	

Notes:

1. The Annualized Cost Estimates were prepared using the methods described in the OAQPS Control Cost Manual 6th Edition and updated chapters.
2. The NOx control options include the following:

NOx Control Option 1: New Low-NOx burner.

NOx Control Option 2: Re-use existing burner, re-use existing forced draft (FD) fan but install flue gas recirculation(FGR). The amount of FGR would be limited by fan capacity.

NOx Control Option 3: Add FGR and replace FD fan to allow greater % of flue gas recirculation.

NOx Control Option 4: New Low-NOx burner, new FD fan, flue gas recirculation.

NOx Control Option 5: New Ultra-Low-NOx burner, new FD fan, flue gas recirculation, damper/drive replacements.
3. The direct operating costs use the following assumptions:

Operating hours per year1000operating hours / yr

Equivalent shifts per year125
4. The man-hours per shift for the Operating Labor and Maintenance Labor were estimated from examples in the OAQPS Control Cost Manual.
5. The direct costs related to utilities were determined using Equation 2.10 from Section 2.6.5.4 of the OAQPS Control Cost Manual (Section 2, Chapter 1) updated Nov 2017. Equation 2.10 is shown below:

$$C_e = \frac{0.746 * Q * \Delta P * s * \theta * p_e}{6356 * \eta}$$

Where:

- Q = gas flow rate (acfm)
- P = pressure drop through system (in. H2O)
- s = specific gravity of gas relative to air
- θ = operating factors (hr/yr)
- η = combined fan and motor efficiency (usually 0.6 to 0.7)
- p_e = electricity cost (\$/kw-hr)

The direct costs related to utilities for Options 1-5 are shown below:

Option 1: There is no additional fan power associated with the low-NOx burner.

Option 2: FGR (4.5% recirculation rate)

Gas flow rate, Q (acfm)	38,197	per 2017 compliance stack test
ΔP (in. H2O)	1.3	Engineering estimate
Additional Fan Power (kWh)	8,966	0.746 x acfm x ΔP x operating hours / (6356 x 0.65)

Options 3 & 4 with 15% FGR (w and wo LNB); Option 5 with 30% FGR

Gas flow rate, Q (acfm)	38,197	per 2017 compliance stack test
ΔP (in. H2O)	4.7	Engineering estimate
Additional Fan Power (kWh)	32,417	0.746 x acfm x ΔP x operating hours / (6356 x 0.65)
Capital Recovery Factor	0.10979	i(1+i) ⁿ / ((1+i) ⁿ -1)
Equipment Life, n (years)	15	
Annual Compounded Interest, i (%)	7%	

Energy Center Pittsburgh
PA DEP RACT II Rule - Case-by-Case NOx RACT Proposal for Boiler 2
Table 2 - Annualized Cost Estimates **

Cost Item	Computation Method	Factor	Costs for Each NOx Control Option					Notes
			Option 1	Option 2	Option 3	Option 4	Option 5	
<u>Direct Operating Costs</u>								
Operating Labor - Operator (OL)	(0.5 man-hours / shift) x (equivalent shifts / yr) x factor	65.00	\$20,313	\$20,313	\$20,313	\$20,313	\$20,313	OAQPS Control Cost Manual; factor = typical loaded labor rate (\$/hr)
Operating Labor - Supervision	OL x factor	0.15	\$3,047	\$3,047	\$3,047	\$3,047	\$3,047	OAQPS Control Cost Manual
Maintenance Labor (ML)	(0.5 man-hours / shift) x (equivalent shifts / yr) x factor	65.00	\$20,313	\$20,313	\$20,313	\$20,313	\$20,313	OAQPS Control Cost Manual; factor = typical loaded labor rate (\$/hr)
Maintenance Materials	100% of ML	1	\$20,313	\$20,313	\$20,313	\$20,313	\$20,313	OAQPS Control Cost Manual
<u>Utilities - Electricity</u>								
Additional Fan Power	Calculation - see below	1						OAQPS Control Cost Manual (Equation 2.10);
KWh	KWh x factor	0.11	<u>\$0</u>	<u>\$3,458</u>	<u>\$12,501</u>	<u>\$12,501</u>	<u>\$12,501</u>	Factor = typical electricity cost (\$/KWh)
Total Direct Operating Costs (DOC)	Sum		\$63,984	\$67,442	\$76,486	\$76,486	\$76,486	
<u>Indirect Operating Costs</u>								
Overhead	(OL + ML) x factor	0.60	\$24,375	\$24,375	\$24,375	\$24,375	\$24,375	OAQPS Control Cost Manual (Section 2.6.5.7)
Insurance	TCI x factor	0.01	\$4,695	\$4,446	\$6,712	\$12,074	\$15,049	OAQPS Control Cost Manual
Administration	TCI x factor	0.02	\$9,389	\$8,892	\$13,424	\$24,147	\$30,099	OAQPS Control Cost Manual
Capital Recovery	TCI x factor	0.10979	<u>\$51,543</u>	<u>\$48,813</u>	<u>\$73,691</u>	<u>\$132,555</u>	<u>\$165,228</u>	Factor per OAQPS Control Cost Manual (Equation 2.8)
Total Indirect Operating Costs (IOC)	Sum		\$90,002	\$86,526	\$118,202	\$193,151	\$234,751	
Total Annualized Cost (TAC)	Sum DOC+ IOC	1	\$153,986	\$153,969	\$194,688	\$269,637	\$311,237	

Notes:

1. The Annualized Cost Estimates were prepared using the methods described in the OAQPS Control Cost Manual 6th Edition and updated chapters.
2. The NOx control options include the following:

NOx Control Option 1: New Low-NOx burner.

NOx Control Option 2: Re-use existing burner, re-use existing forced draft (FD) fan but install flue gas recirculation(FGR). The amount of FGR would be limited by fan capacity.

NOx Control Option 3: Add FGR and replace FD fan to allow greater % of flue gas recirculation.

NOx Control Option 4: New Low-NOx burner, new FD fan, flue gas recirculation.

NOx Control Option 5: New Ultra-Low-NOx burner, new FD fan, flue gas recirculation, damper/drive replacements.
3. The direct operating costs use the following assumptions:

Operating hours per year5000operating hours / yr

Equivalent shifts per year625
4. The man-hours per shift for the Operating Labor and Maintenance Labor were estimated from examples in the OAQPS Control Cost Manual.
5. The direct costs related to utilities were determined using Equation 2.10 from Section 2.6.5.4 of the OAQPS Control Cost Manual (Section 2, Chapter 1) updated Nov 2017. Equation 2.10 is shown below:

$$C_e = \frac{0.746 * Q * \Delta P * s * \theta * p_e}{6356 * \eta}$$

Where:

Q = gas flow rate (acfm)

P = pressure drop through system (in. H2O)

s = specific gravity of gas relative to air

θ = operating factors (hr/yr)

η = combined fan and motor efficiency (usually 0.6 to 0.7)

p_e = electricity cost (\$/kw-hr)

The direct costs related to utilities for Options 1-5 are shown below:
Option 1: There is no additional fan power associated with the low-NOx burner.

Option 2: FGR (4.5% recirculation rate)		
Gas flow rate, Q (acfm)	26,783	per 2017 compliance stack test
ΔP (in. H2O)	1.3	Engineering estimate
Additional Fan Power (kWh)	31,435	0.746 x acfm x ΔP x operating hours / (6356 x 0.65)
Options 3 & 4 with 15% FGR (w and wo LNB); Option 5 with 30% FGR		
Gas flow rate, Q (acfm)	26,783	per 2017 compliance stack test
ΔP (in. H2O)	4.7	Engineering estimate
Additional Fan Power (kWh)	113,650	0.746 x acfm x ΔP x operating hours / (6356 x 0.65)
Capital Recovery Factor	0.10979	i(1+i) ⁿ / ((1+i) ⁿ -1)
Equipment Life, n (years)	15	
Annual Compounded Interest, i (%)	7%	

Energy Center Pittsburgh
PA DEP RACT II Rule - Case-by-Case NOx RACT Proposal for Boiler 3
Table 2 - Annualized Cost Estimates **

Cost Item	Computation Method	Factor	Costs for Each NOx Control Option					Notes
			Option 1	Option 2	Option 3	Option 4	Option 5	
<u>Direct Operating Costs</u>								
Operating Labor - Operator (OL)	(0.5 man-hours / shift) x (equivalent shifts / yr) x factor	65.00	\$28,438	\$28,438	\$28,438	\$28,438	\$28,438	OAQPS Control Cost Manual; factor = typical loaded labor rate (\$/hr)
Operating Labor - Supervision	OL x factor	0.15	\$4,266	\$4,266	\$4,266	\$4,266	\$4,266	OAQPS Control Cost Manual
Maintenance Labor (ML)	(0.5 man-hours / shift) x (equivalent shifts / yr) x factor	65.00	\$28,438	\$28,438	\$28,438	\$28,438	\$28,438	OAQPS Control Cost Manual; factor = typical loaded labor rate (\$/hr)
Maintenance Materials	100% of ML	1	\$28,438	\$28,438	\$28,438	\$28,438	\$28,438	OAQPS Control Cost Manual
<u>Utilities - Electricity</u>								
Additional Fan Power	Calculation - see below	1						OAQPS Control Cost Manual (Equation 2.10);
KWh	KWh x factor	0.11	<u>\$0</u>	<u>\$7,699</u>	<u>\$27,834</u>	<u>\$27,834</u>	<u>\$27,834</u>	Factor = typical electricity cost (\$/KWh)
Total Direct Operating Costs (DOC)	Sum		\$89,578	\$97,277	\$117,412	\$117,412	\$117,412	
<u>Indirect Operating Costs</u>								
Overhead	(OL + ML) x factor	0.60	\$34,125	\$34,125	\$34,125	\$34,125	\$34,125	OAQPS Control Cost Manual (Section 2.6.5.7)
Insurance	TCI x factor	0.01	\$4,870	\$4,446	\$7,277	\$12,982	\$16,005	OAQPS Control Cost Manual
Administration	TCI x factor	0.02	\$9,741	\$8,892	\$14,554	\$25,964	\$32,009	OAQPS Control Cost Manual
Capital Recovery	TCI x factor	0.10979	<u>\$53,473</u>	<u>\$48,813</u>	<u>\$79,895</u>	<u>\$142,527</u>	<u>\$175,714</u>	Factor per OAQPS Control Cost Manual (Equation 2.8)
Total Indirect Operating Costs (IOC)	Sum		\$102,209	\$96,276	\$135,851	\$215,597	\$257,853	
Total Annualized Cost (TAC)	Sum DOC+ IOC	1	\$191,787	\$193,553	\$253,263	\$333,009	\$375,265	

- Notes:
- The Annualized Cost Estimates were prepared using the methods described in the OAQPS Control Cost Manual 6th Edition and updated chapters.
 - The NOx control options include the following:
NOx Control Option 1: New Low-NOx burner.
NOx Control Option 2: Re-use existing burner, re-use existing forced draft (FD) fan but install flue gas recirculation(FGR). The amount of FGR would be limited by fan capacity.
NOx Control Option 3: Add FGR and replace FD fan to allow greater % of flue gas recirculation.
NOx Control Option 4: New Low-NOx burner, new FD fan, flue gas recirculation.
NOx Control Option 5: New Ultra-Low-NOx burner, new FD fan, flue gas recirculation, damper/drive replacements.
 - The direct operating costs use the following assumptions:
Operating hours per year 7000 operating hours / yr
Equivalent shifts per year 875
 - The man-hours per shift for the Operating Labor and Maintenance Labor were estimated from examples in the OAQPS Control Cost Manual.
 - The direct costs related to utilities were determined using Equation 2.10 from Section 2.6.5.4 of the OAQPS Control Cost Manual (Section 2, Chapter 1) updated Nov 2017. Equation 2.10 is shown below:

$$C_e = \frac{0.746 * Q * \Delta P * s * \theta * p_e}{6356 * \eta}$$

Where:
Q = gas flow rate (acfm)
P = pressure drop through system (in. H2O)
s = specific gravity of gas relative to air
θ = operating factors (hr/yr)
η = combined fan and motor efficiency (usually 0.6 to 0.7)
p_e = electricity cost (\$/kw-hr)

The direct costs related to utilities for Options 1-5 are shown below:

Option 1: There is no additional fan power associated with the low-NOx burner.

Option 2: FGR (4.5% recirculation rate)

Gas flow rate, Q (acfm)	42,593	per 2017 compliance stack test
ΔP (in. H2O)	1.3	Engineering estimate
Additional Fan Power (kWh)	69,988	0.746 x acfm x ΔP x operating hours / (6356 x 0.65)

Options 3 & 4 with 15% FGR (w and wo LNB); Option 5 with 30% FGR

Gas flow rate, Q (acfm)	42,593	per 2017 compliance stack test
ΔP (in. H2O)	4.7	Engineering estimate
Additional Fan Power (kWh)	253,032	0.746 x acfm x ΔP x operating hours / (6356 x 0.65)
Capital Recovery Factor	0.10979	i(1+i) ⁿ / ((1+i) ⁿ -1)
Equipment Life, n (years)	15	
Annual Compounded Interest, i (%)	7%	

Energy Center Pittsburgh
PA DEP RACT II Rule - Case-by-Case NOx RACT Proposal for Boiler 1
Table 3 - Cost-Effectiveness Estimates

Control Option No.	Description	Fuel ¹	Boiler Capacity (MMBtu/hr)	Max. Fuel Use Based on Capacity (MMScf/Yr) ²	Fuel Use with Restriction (MMScf/Yr) ³	Current NOx Emission Rate (lb/MMBtu) ⁴	Baseline NOx Emissions (tons/yr) ⁵	Controlled NOx Emission Rate (lb/MMBtu) ⁶	NOx Emissions Post-Control (tons/yr) ⁷	Total Annualized Cost (\$/yr) ⁸	Cost Effectiveness (\$ / ton NOx Reduced)	
											Average	Incremental
1	Low-NOx Burner (LNB)	Natural Gas	92	790	395	0.121	24.4	0.100	20.1	\$83,298	\$19,687	
2	FGR with existing FD Fan	Natural Gas	92	790	395	0.121	24.4	0.100	20.1	\$80,809	\$19,099	Infinite
3	FGR + FD fan	Natural Gas	92	790	395	0.121	24.4	0.050	10.1	\$115,065	\$8,044	\$3,400
4	FGR + FD fan + LNB	Natural Gas	92	790	395	0.121	24.4	0.036	7.3	\$190,014	\$11,095	\$26,571
5	FGR + FD fan + ULNB	Natural Gas	92	790	395	0.121	24.4	0.012	2.4	\$231,614	\$10,546	\$8,603

- Notes:
1. Fuel oil is not included in this analysis; Title V operating permit #0022, Conditions V.B.1.f and V.C.1.f restrict the use of no. 2 fuel oil in Boilers, 1, 2, and 3 to “a backup fuel in emergency situations, including where natural gas is not available or during periods of natural gas curtailment. During periods of curtailment, the permittee shall use their natural gas allotment as specified by the curtailment notice before combusting No. 2 fuel oil.”
2. Maximum natural gas burned calculated based on boiler capacity calculated as follows:
Maximum Natural Gas Burned (MMScf/year) = Boiler Capacity (MMBtu/hr) * 8,760 hours/year / Heating Value (Btu/scf), where
Natural Gas Heating Value (Btu/scf): 1020
3. RACT II Proposal includes a percent fuel reduction restriction of permitted fuel capacity. Proposed percent reduction: 50%
Natural Gas Burned with Fuel Use Restriction (MMScf/year) = Maximum Natural Gas Burned based on Boiler Capacity (MMBtu/hr) * (1-% Reduction)
4. Per Section 129.92(b)(4)(iii), the baseline emissions rate shall be established using either test results or approved emission factors and historic operating data. The baseline emission rate is from stack test data performed on 11/9/2017.
5. Baseline Annual NOx Emissions (TPY) = Fuel Use with Restriction (MMScf/Year) * Baseline NOx Emission Rate (lb/MMBtu) * Heating Value (Btu/scf) / 2000 lbs/ton
6. Post-control NOx emission rates are vendor guarantees for natural gas firing.
7. NOx Emissions Post-Control (TPY) = Fuel Use with Restriction (MMScf/Year) * Controlled NOx Emission Rate (lb/MMBtu) * Heating Value (Btu/scf) / 2000 lbs/ton
8. Annualized costs are summarized here and were calculated in Tables 1 and 2.

Energy Center Pittsburgh
PA DEP RACT II Rule - Case-by-Case NOx RACT Proposal for Boiler 2
Table 3 - Cost-Effectiveness Estimates

Control Option No.	Description	Fuel ¹	Boiler Capacity (MMBtu/hr)	Max. Fuel Use Based on Capacity (MMScf/Yr) ²	Fuel Use with Restriction (MMScf/Yr) ³	Current NOx Emission Rate (lb/MMBtu) ⁴	Baseline NOx Emissions (tons/yr) ⁵	Controlled NOx Emission Rate (lb/MMBtu) ⁶	NOx Emissions Post-Control (tons/yr) ⁷	Total Annualized Cost (\$/yr) ⁸	Cost Effectiveness (\$ / ton NOx Reduced)	
											Average	Incremental
1	Low-NOx Burner (LNB)	Natural Gas	92	790	514	0.14	36.7	0.100	26.2	\$153,986	\$14,698	
2	FGR with existing FD Fan	Natural Gas	92	790	514	0.14	36.7	0.100	26.2	\$153,969	\$14,696	Infinite
3	FGR + FD fan	Natural Gas	92	790	514	0.14	36.7	0.050	13.1	\$194,688	\$8,259	\$3,109
4	FGR + FD fan + LNB	Natural Gas	92	790	514	0.14	36.7	0.036	9.4	\$269,637	\$9,899	\$20,439
5	FGR + FD fan + ULNB	Natural Gas	92	790	514	0.14	36.7	0.012	3.1	\$311,237	\$9,283	\$6,618

Notes:

- Fuel oil is not included in this analysis; Title V operating permit #0022, Conditions V.B.1.f and V.C.1.f restrict the use of no. 2 fuel oil in Boilers, 1, 2, and 3 to “a backup fuel in emergency situations, including where natural gas is not available or during periods of natural gas curtailment. During periods of curtailment, the permittee shall use their natural gas allotment as specified by the curtailment notice before combusting No. 2 fuel oil.”
- Maximum natural gas burned calculated based on boiler capacity calculated as follows:
Maximum Natural Gas Burned (MMScf/year) = Boiler Capacity (MMBtu/hr) * 8,760 hours/year / Heating Value (Btu/scf), where
Natural Gas Heating Value (Btu/scf): 1020
- RACT II Proposal includes a percent fuel reduction restriction of permitted fuel capacity. Proposed percent reduction: 35%
Natural Gas Burned with Fuel Use Restriction (MMScf/year) = Maximum Natural Gas Burned based on Boiler Capacity (MMBtu/hr) * (1-% Reduction)
- Per Section 129.92(b)(4)(iii), the baseline emissions rate shall be established using either test results or approved emission factors and historic operating data. The baseline emission rate is from stack test data performed on 11/9/2017.
- Baseline Annual NOx Emissions (TPY) = Fuel Use with Restriction (MMScf/Year) * Baseline NOx Emission Rate (lb/MMBtu) * Heating Value (Btu/scf) / 2000 lbs/ton
- Post-control NOx emission rates are vendor guarantees for natural gas firing.
- NOx Emissions Post-Control (TPY) = Fuel Use with Restriction (MMScf/Year) * Controlled NOx Emission Rate (lb/MMBtu) * Heating Value (Btu/scf) / 2000 lbs/ton
- Annualized costs are summarized here and were calculated in Tables 1 and 2.

Energy Center Pittsburgh
PA DEP RACT II Rule - Case-by-Case NOx RACT Proposal for Boiler 3
Table 3 - Cost-Effectiveness Estimates

Control Option No.	Description	Fuel ¹	Boiler Capacity (MMBtu/hr)	Max. Fuel Use Based on Capacity (MMScf/Yr) ²	Fuel Use with Restriction (MMScf/Yr) ³	Current NOx Emission Rate (lb/MMBtu) ⁴	Baseline NOx Emissions (tons/yr) ⁵	Controlled NOx Emission Rate (lb/MMBtu) ⁶	NOx Emissions Post-Control (tons/yr) ⁷	Total Annualized Cost (\$/yr) ⁸	Cost Effectiveness (\$ / ton NOx Reduced)	
											Average	Incremental
1	Low-NOx Burner (LNB)	Natural Gas	131.1	1125	1069	0.107	58.3	0.100	54.5	\$191,787	\$50,266	
2	FGR with existing FD Fan	Natural Gas	131.1	1125	1069	0.107	58.3	0.100	54.5	\$193,553	\$50,729	Infinite (neg.)
3	FGR + FD fan	Natural Gas	131.1	1125	1069	0.107	58.3	0.050	27.3	\$253,263	\$8,152	\$2,191
4	FGR + FD fan + LNB	Natural Gas	131.1	1125	1069	0.107	58.3	0.036	19.6	\$333,009	\$8,605	\$10,450
5	FGR + FD fan + ULNB	Natural Gas	131.1	1125	1069	0.107	58.3	0.012	6.5	\$375,265	\$7,247	\$3,230

Notes:

1. Fuel oil is not included in this analysis; Title V operating permit #0022, Conditions V.B.1.f and V.C.1.f restrict the use of no. 2 fuel oil in Boilers, 1, 2, and 3 to “a backup fuel in emergency situations, including where natural gas is not available or during periods of natural gas curtailment. During periods of curtailment, the permittee shall use their natural gas allotment as specified by the curtailment notice before combusting No. 2 fuel oil.”
2. Maximum natural gas burned calculated based on boiler capacity calculated as follows:
Maximum Natural Gas Burned (MMScf/year) = Boiler Capacity (MMBtu/hr) * 8,760 hours/year / Heating Value (Btu/scf), where
Natural Gas Heating Value (Btu/scf): 1020
3. RACT II Proposal includes a percent fuel reduction restriction of permitted fuel capacity. Proposed percent reduction: 5%
Natural Gas Burned with Fuel Use Restriction (MMScf/year) = Maximum Natural Gas Burned based on Boiler Capacity (MMBtu/hr) * (1-% Reduction)
4. Per Section 129.92(b)(4)(iii), the baseline emissions rate shall be established using either test results or approved emission factors and historic operating data. The baseline emission rate is from stack test data performed on 11/9/2017.
5. Baseline Annual NOx Emissions (TPY) = Fuel Use with Restriction (MMScf/Year) * Baseline NOx Emission Rate (lb/MMBtu) * Heating Value (Btu/scf) / 2000 lbs/ton
6. Post-control NOx emission rates are vendor guarantees for natural gas firing.
7. NOx Emissions Post-Control (TPY) = Fuel Use with Restriction (MMScf/Year) * Controlled NOx Emission Rate (lb/MMBtu) * Heating Value (Btu/scf) / 2000 lbs/ton
8. Annualized costs are summarized here and were calculated in Tables 1 and 2.

APPENDIX B

BOILER VENDOR DATA



The Babcock & Wilcox Company

► 277 Fairfield Road ► Suite 331A ► Fairfield, NJ 07004
► Phone 973.227.7008 ► Fax 973.227.7009 ► www.babcock.com

Nov 13, 2019

Via Email

Clearway Energy, Inc.
111 South Commons Ave
Pittsburgh, PA 15212

Attn: Mr. Bard Rupp

Re: Orig. B&W Contract FM-1158 (2 boilers) & FM-2199
Subj: RACT 2 Filing Analysis Support

Dear Mr. Rupp:

Following our conversation last week regarding your upcoming RACT 2 filing, we wanted to summarize the analysis we completed related to NOx control technologies that could be available to the three referenced B&W boilers at your Pittsburgh steam plant. This analysis was a continuation of similar work we did for this facility in 2016. There are a number of NOx reduction strategies that can be used depending on existing equipment arrangement, the fuel being burned, NOx target levels and of course project costs. The following is a summary of the options reviewed:

- Option 1: New Low-NOx burner.
- Option 2: Re-use existing burner, re-use existing forced draft (FD) fan but install flue gas recirculation (FGR). The amount of FGR would be limited by fan capacity.
- Option 3: Add FGR and replace FD fan to allow greater % of flue gas recirculation.
- Option 4: New Low-NOx burner, new FD fan, flue gas recirculation.
- Option 5: New Ultra-Low-NOx burner, new FD fan, flue gas recirculation, damper/drive replacements

The attached spreadsheet summarizes the predicted NOx reduction from each of the strategies listed above. The sheet also includes estimated material and installation costs. I should note that while Option 5 is likely possible to retrofit on the existing boilers, we typically see requests for Options 2, 3 or 4. Ultra-Low-NOx burners are very tightly controlled, are more susceptible to any upsets in the process and would bring more risk of success considering the age of the existing equipment.

If we can be of further assistance please do not hesitate to contact me at 603-498-1207 or via e-mail at ladimke@babcock.com.

Sincerely,

A handwritten signature in black ink, appearing to read 'Luke Dimke'.

Luke Dimke – District Engineer - Northeast



Clearway Energy Pittsburgh Steam Plant

11/13/2019

							Pricing is estimated +/- 20%		
FM-1158 (2 Units)	NOx	Units	NOx	Units	% FGR	Equipment Required	Material	Labor	Total
Natural Gas - Case 1	0.100	LB/MMBTU	82	PPM*	0	New Burner	\$182,938	\$110,872	\$293,810
Natural Gas - Case 2	0.100	LB/MMBTU	82	PPM*	4.5	FGR Duct	\$119,742	\$160,764	\$280,506
Natural Gas - Case 3	0.050	LB/MMBTU	41	PPM*	15	FD Fan/FGR Duct	\$194,026	\$232,831	\$426,856
Natural Gas - Case 4	0.036	LB/MMBTU	30	PPM*	15	Burner/FD Fan/FGR Duct	\$376,964	\$395,812	\$772,776
Natural Gas - Case 5	0.012	LB/MMBTU	10	PPM*	30	Burner/FD Fan/FGR Duct	\$526,964	\$435,394	\$962,358
* Corrected to 3% O2 Dry									
							Pricing is estimated +/- 20%		
FM-2199	NOx	Units	NOx	Units	% FGR	Equipment Required	Material	Labor	Total
Natural Gas - Case 1	0.100	LB/MMBTU	82	PPM*	0	New Burner	\$194,026	\$110,872	\$304,897
Natural Gas - Case 2	0.100	LB/MMBTU	82	PPM*	4.5	FGR Duct	\$119,742	\$160,764	\$280,506
Natural Gas - Case 3	0.050	LB/MMBTU	41	PPM*	15	FD Fan/FGR Duct	\$210,656	\$252,788	\$463,444
Natural Gas - Case 4	0.036	LB/MMBTU	30	PPM*	15	Burner/FD Fan/FGR Duct	\$404,682	\$426,856	\$831,538
Natural Gas - Case 5	0.012	LB/MMBTU	10	PPM*	30	Burner/FD Fan/FGR Duct	\$554,682	\$469,542	\$1,024,224
* Corrected to 3% O2 Dry									
							Pricing is estimated +/- 20%		
All Three Units						Equipment Required	Material	Labor	Total
Natural Gas - Case 1						New Burner	\$559,903	\$332,615	\$892,518
Natural Gas - Case 2						FGR Duct	\$359,225	\$482,292	\$841,517
Natural Gas - Case 3						FD Fan/FGR Duct	\$598,708	\$718,449	\$1,317,157
Natural Gas - Case 4						Burner/FD Fan/FGR Duct	\$1,158,610	\$1,218,481	\$2,377,091
Natural Gas - Case 5						Burner/FD Fan/FGR Duct	\$1,608,610	\$1,340,329	\$2,948,939

ALLEGHENY COUNTY HEALTH DEPARTMENT
BUREAU OF ENVIRONMENTAL QUALITY
Division of Air Quality

IN RE:

Pittsburgh Thermal)	
Limited Partnership)	PLAN APPROVAL ORDER
111 South Commons Avenue)	AND AGREEMENT NO. <u>220</u>
P. O. Box 6929)	<u>UPON CONSENT</u>
Allegheny County)	
Pittsburgh, PA 15212)	

AND NOW, this 4 day of March, 1996,

WHEREAS, the Allegheny County Health Department, Bureau of Environmental Quality, Division of Air Quality (hereafter referred to as "Bureau"), has determined that the Pittsburgh Thermal Limited Partnership (hereafter referred to as "PTLP"), 111 South Commons Avenue, Pittsburgh, Allegheny County, PA 15212, as the operator and the owner of its steam generation facility at 111 South Commons Avenue, Pittsburgh, Allegheny County, PA 15212 (hereafter referred to as "the facility"), is a major stationary source of "oxides of nitrogen" emissions (hereafter referred to as "NO_x") as defined of 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 Bureau has determined that Section 2105.06.a. of Article XXI, entitled "Major Source of NO_x's" is applicable to PTLP'S operations; and

WHEREAS, PTLP promptly submitted to the Bureau all documents required of Section 2105.06.b of Article XXI (hereafter referred to as "the proposal"); and

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

WHEREAS, the Bureau 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's emissions from PTLP; and

WHEREAS, the parties have agreed that the most appropriate vehicle for both memorializing the submitted proposal and approving the submitted proposal by the Bureau for the purpose of submission of the same to the U.S. Environmental Protection Agency (hereafter referred to as "US EPA") as a revision to the Commonwealth of Pennsylvania State Implementation Plan (hereafter referred to as "SIP") is a Plan Approval Order and Agreement Upon Consent; and

WHEREAS, the Bureau and PTLP desire to memorialize the details of the submitted proposal by entry of an Plan Approval Order and Agreement Upon Consent; and

WHEREAS, pursuant to Section 2109.03 of Article XXI, the Director of the Allegheny County Health Department or his

designated representative may take action in order to aid in the enforcement of the provisions this Article; and

NOW, THEREFORE, this first day above written, the Bureau, pursuant of Section 2109.03 of Article XXI, and upon agreement of the parties as hereinafter set forth, hereby issues this Enforcement Order and Agreement upon Consent:

I. ORDER

- 1.1. At no time shall PTLP allow emissions from the facility to exceed the following limitations:

Unit Number	NO _x lbs/mmBTU	TPY
1	0.145	54.2
2	0.145	54.2
3	0.145	77.3

- 1.2. At no time shall PTLP operate boilers one (1), two (2), and three (3) unless all process equipment and O₂ trim equipment are properly operated and maintained according to good engineering practice.

- 1.3. At no time shall PTLP operate boilers 1, 2 and 3 using any fuel other than natural gas (hereafter referred to as "NG") with the exception of

emergency conditions and/or NG curtailment.

1.4. The facility shall perform NO_x emission testing on boiler 3 every 2 years in order to demonstrate compliance with the emission limitations referenced in paragraph 1.1 above. Such testing shall be conducted in accordance with all applicable US EPA approved test methods and Section 2108.02 of Article XXI.

1.5. PTLP shall maintain all appropriate records to demonstrate compliance with both the requirements of Section 2105.06 of Article XXI and this Order. Such records shall provide sufficient data and calculations to demonstrate that all requirements of Section 2105.06 of Article XXI and this Order are being met. Such records shall include, but not be limited to, the following:

A. production data on a daily basis for each boiler:

1. total fuel consumption and type consumed;
2. amount of fuel usage, (mmBTU/day and/or gallon(s)/day);
3. steam load, (mlbs/day); and
4. total operating hours, (hours/day and hours/year).

B. all operation, maintenance, inspection

calibration and/or replacement of fuel-burning equipment--(i. e. replacement of burner(s), adjustment of flame pattern and/or air-to-fuel ratio, ...etc.).

- 1.6. PTLP shall retain all 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 Bureau upon request.

II. AGREEMENT

The foregoing Order shall be enforced in accordance with and is subject to the following agreement of the parties, to wit:

- 2.1. The contents of this Order shall be submitted to The US EPA as a revision to the Commonwealth of Pennsylvania's SIP.
- 2.2. Failure to comply with any portion of this Order or Agreement is a violation of Article XXI that may subject PTLP to criminal and civil proceedings, including injunctive relief, by the Bureau.
- 2.3. This Order does not, in any way, preclude, limit or otherwise affect any other remedies available to the Bureau 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.

2.4. PTLP hereby consents to the foregoing Order and hereby knowingly waives all rights to appeal said Order, and the undersigned represents that he is authorized to consent to the Order and to enter into this Agreement on behalf of PTLP.

2.5.

PTLP acknowledges and understands that the purpose of this Agreement is to establish RACT for the control of emissions of NO_x's from this facility. PTLP further acknowledges and understands the possibility that the US EPA may decide to not accept the Agreement portion of the Enforcement Order and Agreement by Consent as a revision to the Commonwealth of Pennsylvania's SIP.

NO
SIP

IN WITNESS WHEREOF, and intending to be legally bound,
the parties hereby consent to all of the terms and conditions of
the foregoing Order and Agreement as of the date of the above
written.

PITTSBURGH THERMAL LIMITED PARTNERSHIP

By: James S. Cummings

(signature)

Print or type Name: JAMES S. CUMMINGS

Title: PRES.

Date: 4 MAR 96

ALLEGHENY COUNTY HEALTH DEPARTMENT

By: Bruce W. Dixon 7/9/

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

and By: Ronald J. Chlebowski

Ronald J. Chlebowski, Deputy Director
Bureau of Environmental Quality



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

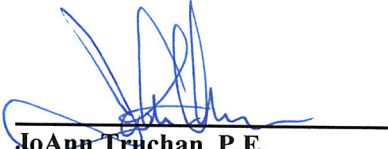
Minor Source/Minor Modification
INSTALLATION PERMIT

Issued To: **Energy Center Pittsburgh LLC**
 North Shore Plant
 111 South Commons
 Pittsburgh, PA 15212

ACHD Permit#: **0022-1003**

Date of Issuance: **March 18, 2020**

Expiration Date: **(See Section III.12)**

Issued By: 
 JoAnn Truchan, P.E.
 Section Chief, Engineering

Prepared By: 
 David D. Good
 Air Quality Engineer

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AMENDMENTS:

<i>DATE</i>	<i>SECTION(S)</i>
-------------	-------------------

I. CONTACT INFORMATION

Facility Location: **Energy Center Pittsburgh LLC – North Shore Plant**
111 South Commons
Pittsburgh, PA 15212

Permittee/Owner: **Energy Center Pittsburgh LLC**
111 South Commons
Pittsburgh, PA 15212

Permittee/Operator: **Same as Above**

Responsible Official: **Brian Goss**
Title: Plant Manager
Company: Energy Center Pittsburgh LLC
Address: 111 South Commons
Pittsburgh, PA 15212
Telephone Number: 412-231-0409
Fax Number: 412-231-0428
E-mail Address: Brian.Goss@clearwayenergy.com

Facility Contact: **Brian Goss**
Title: Plant Manager
Telephone Number: 412-231-0409
Fax Number: 412-231-0428
E-mail Address: Brian.Goss@clearwayenergy.com

AGENCY ADDRESSES:

ACHD Engineer: **Hafeez Ajenifuja**
Title: Air Quality Engineer
Telephone Number: 412-578-8132
Fax Number: 412-578-8144
E-mail Address: hafeez.ajenifuja@alleghenycounty.us

ACHD Contact: **Chief Engineer**
Allegheny County Health Department
Air Quality Program
301 39th Street, Building #7
Pittsburgh, PA 15201-1891

EPA Contact: **Enforcement Programs Section (3AP12)**
USEPA Region III
1650 Arch Street
Philadelphia, PA 19103-2029

II. FACILITY DESCRIPTION

FACILITY DESCRIPTION

The Energy Center Pittsburgh LLC North Shore Plant is a commercial district heating and cooling plant located at 111 South Commons Avenue in the North Shore section of Pittsburgh, PA. The plant supplies steam for space heating and hospital sterilization and chilled water for summer air conditioning to commercial and institutional sites in that area. The plant is composed of five (5) boilers, which fire natural gas as their primary fuel and have the capacity to fire no. 2 fuel oil, in lieu of natural gas at times of emergency or natural gas curtailment with the exception boilers 4 & 5. Additional equipment used for chilled water production includes various turbines, chillers and compressors, a two 3-cell 33,000 gpm cooling tower (sharing a common basin) and a 2-cell 7,200 gpm cooling tower. The facility is a major source of nitrogen oxides (NO_x) and carbon monoxide (CO) and minor source of particulate matter (PM), particulate matter < 10 microns in dia. (PM-10), sulfur dioxide (SO₂), 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 facilities pursuant to Reasonable Available Control Technology (RACT) 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
B001	Babcock & Wilcox forced draft, water tube boiler	None	92.0 MMBtu/hr	Natural gas, No. 2 fuel oil (emergency backup)
B002	Babcock & Wilcox forced draft, water tube boiler	None	92.0 MMBtu/hr	Natural gas, No. 2 fuel oil (emergency backup)
B003	Babcock & Wilcox forced draft, water tube boiler	None	131.1 MMBtu/hr	Natural gas, No. 2 fuel oil (emergency backup)

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)

- a. 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
- b. 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 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 within 30 days of the end of the calendar half.
- e. Quarterly reports required by this permit shall be submitted to the Department within 30 days of the end of the calendar quarter.
- f. Reports may be emailed to the Department at aqreports@achd.net 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 insure 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.

21. National Emission Standards for Hazardous Air Pollutants (§2104.08)

- a. The permittee shall comply with each applicable emission limitation, work practice standard, and operation and maintenance requirement of 40 CFR Part 63, Subpart DDDDD – *National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters*, CFR Part 63, Subpart UUUUU – *National Emission Standards for Hazardous Air Pollutants for Coal- and Oil-Fired electric Utility Steam Generating Units*, and CFR Part 63, Subpart ZZZZ – *National Emission Standards for Stationary Reciprocating Internal Combustion Engines*.

V. EMISSION UNIT LEVEL TERMS AND CONDITIONS

A. Boilers No. 1 & No 2

Process Description:	Two identical Babcock & Wilcox, forced draft water tube boilers
Facility ID:	B001, B002
Maximum Design Rate:	92.0 MMBtu/hr each
Fuel(s):	Natural gas and no. 2 fuel oil as an emergency fuel
Control Device(s):	None

1. Restrictions:

- a. The permittee shall continue to meet the conditions of Operating Permit No. 0022, in addition to the revisions in this permit. (§2102.04.b.5)
- b. At no time shall the permittee allow emissions of nitrogen oxides from each boiler to exceed 0.145 pounds per MMBtu at any time. The annual nitrogen oxides limits for boiler no. 1 and boiler no. 2 are 24.4 tons and 36.7 tons, respectively, during any 12 consecutive month period. (§2105.06, 25 Pa. Code §129.99)
- c. At no time shall the permittee operate boilers no. 1 or no. 2 unless all process equipment and O₂ trim equipment are properly operated and maintained according to condition V.A.3.a. (RACT Order #220, Condition 1.2; §2105.0625 Pa. Code §129.99)
- d. At no time shall the permittee operate boiler no. 1 or no. 2 using any fuel other than natural gas with the exception of no.2 fuel oil which may be combusted only during emergency conditions and/or natural gas curtailment. (RACT Order #220, Condition 1.3; §2105.06, 25 Pa. Code §129.99)
- e. Natural gas usage in boiler no. 1 shall not exceed the maximum potential usage of 90,200 scf/hr and 395 million scf/yr. Natural gas usage in boiler no. 2 shall not exceed the maximum potential usage of 90,200 scf/hr and 514 million scf/yr. (§2103.12.h.1; §2103.12.a.2.C, 25 Pa. Code §129.99)
- f. No. 2 fuel oil combusted in each boiler shall not exceed 660 gal/hr and 330,000 gallons in any consecutive twelve-month period, at any time. All fuel oil combusted shall meet current ASTM specifications for no.2 fuel oil and contain 0.05% sulfur (wt. percent) or less. (§2103.12.h.1, 25 Pa. Code §129.99)
- g. Emissions from boiler no. 1 and boiler no. 2, shall not exceed the following limitations in Table V-A-1 or V-A-2 at any time: (§2104.02.a.1, §2105.06, §2101.02.c.4, §2103.12.a.2.B, 25 Pa. Code §129.99)

TABLE V-A-1: Boiler No. 1 Emission Limitations

POLLUTANT	Natural Gas (lb/hr)	No. 2 Fuel Oil (lb/hr)	ANNUAL EMISSION LIMIT (tons/year) ¹
Nitrogen Oxides	13.34	13.25	24.4

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

TABLE V-A-2: Boiler No. 2 Emission Limitations

POLLUTANT	Natural Gas (lb/hr)	No. 2 Fuel Oil (lb/hr)	ANNUAL EMISSION LIMIT (tons/year) ¹
Nitrogen Oxides	13.34	13.25	36.7

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

2. Testing Requirements:

- a. While combusting natural gas, the permittee shall perform NO_x emission testing on boilers no.1 & no.2, at least once every two (2) years from the most recent stack test. Such testing shall consist of methods no. 1 through no. 5 and no. 7E of appendix A of 40 CFR 60 and be conducted in accordance with such test methods and §2108.02 of Article XXI. (RACT Order #220, Condition 1.4; §2105.06; §2103.12.h.1; §2108.02 and §2103.12.i, 25 Pa. Code §129.100)
- b. The permittee shall perform NO_x and particulate matter testing after accruing 40 or more operating hours in any consecutive 12-month period while firing fuel oil resulting from periods of gas curtailment or gas supply interruption in order to demonstrate compliance with the fuel oil NO_x, and particulate emission limitations in conditions in conditions V.A.1.g. Such testing shall be conducted in accordance with Article XXI §2108.02 and as part of the next regularly-scheduled test program required in condition V.A.2.a above. The permittee shall not be required to repeat the fuel oil testing more often than once in any five year period, unless requested to do so by the Department. (§2108.02 and §2103.12.i)
- 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 continuously monitor the oxygen content of the flue gas of each boiler to within 2% of actual and record the oxygen content to the nearest 0.2%, to ensure the boilers are being operated and maintained properly and are operating under the conditions demonstrated during the most recent compliance test. (§2103.12.i; §2108.03, 25 Pa. Code §129.100)

4. Record Keeping Requirements:

- a. The permittee shall keep and maintain the following data for boilers no. 1 and no.2 (RACT Order #220, Condition 1.5; §2105.06; §2103.12.h.1 and §2103.12.j, 25 Pa. Code §129.100):
 - 1) Fuel consumption (daily, monthly, and 12-month), type of fuel consumed and suppliers' certification of sulfur content, and heating value;
 - 2) Steam load, (mlbs/day, monthly average);
 - 3) Flue gas oxygen (continuously, monthly average)
 - 4) Cold starts (date, time and duration of each occurrence);
 - 5) Total operating hours, (hours/day, monthly and 12-month); and
 - 6) Records of operation, maintenance, inspection, calibration and/or replacement of combustion equipment.

- 7) Stack test protocols and reports.
- 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. (§2103.12.h.1, 25 Pa. Code §129.100)
- 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. [§2103.12.j.2, 25 Pa. Code §129.100]

5. Reporting Requirements:

- a. The permittee shall report the following information to the Department within thirty days of the end of each calendar half. The reports shall contain all required information for the time period of the report: (§2103.12.k.1, 25 Pa. Code §129.100)
 - 1) Monthly and 12-month data required to be recorded by condition V.A.4.a above;
 - 2) Cold start information; and
 - 3) Non-compliance information required to be recorded by V.A.4.b above.
- b. 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:

The permittee shall at all times properly operate and maintain all process and emission control equipment at the facility according to good engineering practice. (25 Pa. Code §129.99)

B. Boiler No. 3

Process Description: One Babcock & Wilcox, forced draft water tube, natural gas-fired boiler
Facility ID: B003
Capacity: 131.1 MMBtu/hr
Fuel(s): Natural gas and no. 2 fuel oil as an emergency fuel
Control Device: None

1. Restrictions:

- a. The permittee shall continue to meet the conditions of Operating Permit No. 0022, in addition to the revisions in this permit. [§2102.04.b.5]
- b. At no time shall the permittee allow emissions of nitrogen oxides from boiler 3 to exceed 0.145 pounds per MMBtu at any time and 58.3 tons during any 12 consecutive months (Condition 1.1; §2105.06, 25 Pa. Code §129.99).
- c. At no time shall the permittee operate boiler no. 3 unless all process equipment and O₂ trim equipment are properly operated and maintained according to condition V.B.3.a (RACT Order #220, Condition 1.2; §2105.06, 25 Pa. Code §129.99).
- d. At no time shall the permittee operate boiler no. 3 using any fuel other than natural gas with the exception of no.2 fuel oil which may be combusted only during emergency conditions and/or natural gas curtailment (RACT Order #220, Condition 1.3; §2105.06, 25 Pa. Code §129.99).
- e. Natural gas usage in boiler no.3 shall not exceed the maximum potential usage of 128,430 scf/hr and 1,069 million scf/yr. (§2103.12.h.1, 25 Pa. Code §129.99)
- f. No. 2 fuel oil combustion in boiler no.3 shall not exceed 940 gal/hr and 470,000 gallons in any consecutive twelve-month period, at any time. All fuel oil combusted shall meet current ASTM specifications for no.2 fuel oil and shall contain 0.05% sulfur (wt. percent) or less. (§2103.12.h.1, 25 Pa. Code §129.99)
- g. Emissions from boiler no. 3 shall not exceed the emission limitations in Table V-B-1 at any time: (§2104.02.a.1, §2105.06, §2101.02.c.4, §2103.12.a.2.B, 25 Pa. Code §129.99)

TABLE V-B-1: Boiler No. 3 Emission Limitations

POLLUTANT	Natural Gas (lb/hr)	No. 2 Fuel Oil (lb/hr)	ANNUAL EMISSION LIMIT (tons/year) ¹
Nitrogen Oxides	19.01	22.65	58.3

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

2. Testing Requirements:

- a. While combusting natural gas, the permittee shall perform NO_x emission testing on boilers no.1 & no.2, at least once every two (2) years from the most recent stack test. Such testing shall consist of methods no. 1 through no. 5 and no. 7E of appendix A of 40 CFR 60 and be conducted in accordance

with such test methods and §2108.02 of Article XXI. (RACT Order #220, Condition 1.4; §2105.06; §2103.12.h.1; §2108.02 and §2103.12.i, 25 Pa. Code §129.100)

- b. The permittee shall perform NO_x and particulate matter testing on boiler No 3 after accruing 40 or more operating hours in any consecutive 12-month period while firing fuel oil resulting from periods of gas curtailment or gas supply interruption to demonstrate compliance with conditions V.B.1.b and V.B.1.g. Such testing shall be conducted in accordance with Article XXI §2108.02, and as part of the next regularly scheduled test required in condition V.B.2.a above. The permittee shall not be required to repeat the fuel oil testing more often than once in any five year period, unless requested to do so by the Department. (§2108.02 and §2103.12.i)
- 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. [§2108.02]

3. Monitoring Requirements:

- a. The permittee shall continuously monitor the oxygen content of the flue gas of the boiler to within 2% of actual and shall record the percent oxygen content to the nearest 0.2%, to ensure the boiler is being operated and maintained properly and is operating under the conditions demonstrated during the most recent compliance test to meet the lb/MMBtu requirements of the NO_x RACT. (§2103.12.i; §2108.03; §2102.04.e, 25 Pa. Code §129.100)
- b. The permittee shall inspect boiler no.3 weekly, to insure compliance with condition V.B.1.c above. (§2103.12.i; §2102.04.e, 25 Pa. Code §129.100)

4. Record Keeping Requirements:

- a. The permittee shall keep and maintain the following data for Boiler No. 3 (RACT Order #220, Condition 1.5; §2105.06; §2103.12.h.1 and §2103.12.j, 25 Pa. Code §129.100):
 - 1) Fuel consumption (daily, monthly, and 12-month), type of fuel consumed and suppliers' certification of sulfur content and heating value;
 - 2) Steam load, (mlbs/day, monthly average);
 - 3) Flue gas oxygen (continuously, monthly average);
 - 4) Cold starts (date, time and duration of each occurrence);
 - 5) Total operating hours (hours/day), monthly and 12-month);
 - 6) Records of operation, maintenance, inspection calibration and/or replacement of combustion equipment, and
 - 7) Stack test protocols and reports.
- 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. (§2103.12.h.1, 25 Pa. Code §129.100)
- c. All records shall be retained by the facility for at least five (5) years. These records shall be made available to the Department upon request for inspection and/or copying. (§2103.12.j.2, 25 Pa. Code §129.100)

5. Reporting Requirements:

- a. The permittee shall report the following information to the Department within thirty days of the end of each calendar half. The reports shall contain all required information for the time period of the report: (§2103.12.k.1, 25 Pa. Code §129.100)
 - 1) Monthly and 12-month data required to be recorded by condition V.B.4.a above;
 - 2) Cold start information; and
 - 3) Non-compliance information required to be recorded by V.B.4.b above.
- b. Until terminated by written notice from the Department, the requirement for the permittee to report cold starts 24 hours in advance in accordance with §2108.01.d is waived and the permittee may report all cold starts in accordance with Condition V.B.5.a above. (§2108.01.d, §2103.12.k.1)
- 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:

The permittee shall at all times properly operate and maintain all process and emission control equipment at the facility according to good engineering practice. (25 Pa. Code §129.99)

VI. ALTERNATIVE OPERATING SCENARIOS

No alternative operating scenarios exist for this operation.

VII. EMISSIONS LIMITATIONS SUMMARY

The following table summarizes the estimated annual maximum potential emissions (which may not include fugitive) from Boilers 1, 2 and 3 at the Energy Center North Shore Plant. These annual (consecutive 12 month) potential emission estimates assume that all three boilers operate continuously according to to their permit conditions.

TABLE VII-1: Boiler 1, 2 and 3 Emission Limitations Summary

POLLUTANT	ANNUAL EMISSION LIMIT (tons/year)*
Nitrogen Oxides (NO _x)	119.4

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