APPENDIX A-4

Source ID# 089-00118

Cleveland-Cliffs Steel, LLC-Gary Plate Facility

NOx RACT Study

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NO_X REASONABLY AVAILABLE CONTROL TECHNOLOGY STUDY

CLIFFS

Cleveland-Cliffs Gary Plate, LLC| Gary, Indiana

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1. BACKGROUND

Cleveland-Cliffs Steel LLC (Cleveland-Cliffs) owns and operates a heat treatment facility located in Gary, Lake County, Indiana (referred to herein as "Gary Plate" or "CCGP"), consisting of the following units which emit nitrogen oxides (NO_X):

- One natural gas (NG)-fired **Plate Mill Heat Treatment Furnace** (LOI), identified as ID #28, installed in 1997 and permitted in 2020 to install and operate new burners, with an estimated maximum heat input capacity of 60.64 MMBtu per hour, exhausting to a Stack PMHTStk1.
- Two NG-fired Hardening Furnaces, identified as **North Hardening Furnace** (ID #24 installed in 1969) and **South Hardening Furnace** (ID #26 installed in 1962), having an estimated heat input capacity of 100 MMBtu per hour each, exhausting through Roof Monitor PMRm1.
- Two NG-fired Tempering Furnaces, identified as **North Tempering Furnace** (ID #25 installed in 1969) and **South Tempering Furnace** (ID #27 installed in 1962), having an estimated maximum heat input capacity of 100 MMBtu per hour each, exhausting through Roof Monitor PMRm1.
- Small sources such as 11 NG-fired bug burners, four Gantry burners, and NG-fired space heaters.

To support development of a State Implementation Plan (SIP) for meeting the 2015 8-hour ozone National Ambient Air Quality Standards (NAAQS) in the "moderate" nonattainment areas of Lake and Porter counties, the Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ), requested a NO_X Reasonably Available Control Technology (RACT) analysis for the units at CCGP. The following submittal reflects CCGP's RACT analysis in response to this request. Given the limited amount of time to prepare this response, CCGP may supplement this analysis response as needed as the rulemaking process proceeds forward.

2. FACILITY OVERVIEW

2.1 General Facility Information

CCGP is a stationary heat treatment facility located at One North Broadway Avenue, Gary, Indiana 46402. CCGP currently operates under Title V operating permit No. 089-44016-00118.

Figure 2-1 is an area map that shows the site location relative to predominant geographical features such as highways and railroads.

Cleveland-Cliffs has provided the following information to assist IDEM in processing this analysis.

(a) The complete facility name and address:

Cleveland-Cliffs Burns Harbor LLC – Gary Plate
One North Broadway Avenue
Gary, Indiana 46402

(b) The name, title, address and telephone number of the owner or operator's representative within the company who is the contact person for this facility regarding the engineering study and affected sources:

Thomas Maicher
Area Manager, Environmental
219-787-4961

(c) The name, title, address and telephone number of the official who is responsible for approval of the engineering study:

Mark A. Dutler
Senior General Manager Burns Harbor
219-787-3081

(d) The standard industrial classification code and source classification code numbers which are applicable to the facility's operation:

3398 (Metal Heat Treating)

Figure 2-1. Area Map of CCGP

2.2 Permitted NO_X Sources

Table 2-1 summarizes the Title V permitted NO_X sources at CCGP, along with the corresponding potential to emit (PTE) of NO_X for each unit.

Table 2-1. PTE of NO_X-Emitting Sources at CCGP

Emission Unit ID	Emission Unit Description	Rated Capacity (MMBtu/hr)	Fuels Burned	NO_X PTE (tpy)
24	North Hardening Furnace	100	NG	42.94
25	North Tempering Furnace	100	NG	42.94
26	South Hardening Furnace	100	NG	42.94
27	South Tempering Furnace	100	NG	42.94
28	Plate Mill Heat Treatment Furnace	60.64	NG	24.92[a]
31	Bug Burners (11)	1.21	NG	0.52
19	Plate Cutting (Gantry Burners) (4)	2.0	NG	0.86
NA	Space Heaters	20	NG	8.59

[a] *PTE is limited to 24.92 tpy NO_X as of issuance of the latest Title V permit. Unconstrained emissions are 46.48 tpy NO_X.*

Table 2-2 provides the Title V permitted NO_X sources and whether the unit is subject to the RACT requirements, the applicable RACT requirement for each unit, and (if applicable) the justifications for exclusion from the RACT regulations. The NO_X RACT regulations specify presumptive NO_X emission limits for the following source types:

- Boilers and process heaters
- Stationary combustion turbines
- Stationary internal combustion engines
- Iron and steel production sources (reheat, annealing, and galvanizing furnaces > 75 MMBtu/hr)

Table 2-2. Summary of Permitted NO_X Sources Subject to RACT Regulations

Emission Unit ID	Emission Unit Description	NO_X RACT Applicability	RACT EU Classification	Presumptive NO_X Limit (lb/MMBtu)	Exemption Justification
24	North Hardening Furnace	Presumptive RACT	Annealing Furnace	0.09	--
25	North Tempering Furnace	Presumptive RACT	Annealing Furnace	0.09	--
26	South Hardening Furnace	Presumptive RACT	Annealing Furnace	0.09	--
27	South Tempering Furnace	Presumptive RACT	Annealing Furnace	0.09	--
28	Plate Mill Heat Treatment Furnace	Exempt	--	--	< 25 tpy PTE
31	Bug Burners (11)	Exempt	--	--	< 25 tpy PTE
19	Plate Cutting (Gantry Burners) (4)	Exempt	--	--	< 25 tpy PTE
NA	Space Heaters	Exempt	--	--	< 25 tpy PTE

For each unit subject to the presumptive NO_X RACT emission limit of 0.09 lb NO_X/MMBtu, CCGP is proposing an alternative RACT limit. The rationale for the alternative limit is provided in the remainder of this report.

3. RACT DEFINITION AND METHODOLOGY

"RACT," "BACT," and "LAER" are acronyms for different levels of emissions control. The least stringent is RACT, more stringent is BACT, and the most stringent is LAER. The type of control required depends on the size of the stationary source and whether it is located in an attainment or nonattainment area.

- RACT, or Reasonably Available Control Technology, is required on new minor sources and existing major sources of NO_X and VOC in the ozone NAA.
- BACT, or Best Available Control Technology, is required for new major stationary sources and major modifications in attainment areas subject to Prevention of Significant Deterioration (PSD) permitting requirements.
- LAER, or Lowest Achievable Emission Rate, is required for new major stationary sources and major modifications in non-attainment areas subject to Nonattainment New Source Review permitting requirements.

At the federal level, RACT is not defined by statue or rule, rather it is defined in U.S. Environmental Protection Agency's (U.S. EPA) guidance 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."[1]

Considering this definition, RACT involves identifying implementable control technologies with due consideration given to technological and economic feasibility. Since RACT considers the technological and economic impacts of controls, the analysis and determination may differ from source to source and location to location.

3.1 Top-down Approach

In this RACT study, CCGP is using the U.S. EPA's top-down approach to determining the feasibility of control technology where the most stringent control available for a similar or identical source or source category is identified. This control option is used to establish the RACT emission limitation, unless the applicant can demonstrate (and the permitting authority agrees) that it is not "achievable" due to technical infeasibility or not being cost effective and potentially having other adverse environmental or energy consequences of implementing the technology. If the top control alternative is eliminated, then the next most stringent level of control is evaluated. This process continues until RACT is selected. The five steps in a top-down RACT evaluation can be summarized as follows:

- Step 1. Identify all possible control technologies
- Step 2. Eliminate technically infeasible options
- Step 3. Rank the technically feasible control technologies based upon emission reduction potential
- Step 4. Evaluate ranked controls based on energy, environmental, and/or economic considerations
- Step 5. Select RACT

The following sections contain a description of the five (5) basic steps of this "top-down" approach.

[1] 44 Fed. Reg. 53762 (9/17/1979)

3.1.1 Step 1 – Identify All Control Options

In this step, available control technologies with the practical potential for application to the emission unit and regulated air pollutant in question are identified. The selected control technologies vary widely depending on the process technology and pollutant being controlled. The application of demonstrated control technologies in other similar source categories to the emission unit in question may also be considered in this step.

The following resources are typically consulted when identifying potential technologies for criteria pollutants:

- EPA's RACT/BACT/LAER Clearinghouse (RBLC) database
- NSPS, NESHAP, and RACT regulations for similar operations
- Engineering experience with similar control applications
- Information provided by air pollution control equipment vendors with significant market share in the industry

3.1.2 Step 2 – Eliminate Technically Infeasible Options

In this step, "technically infeasible" control options from the list of "potentially available" control options are eliminated. A control option is "technically feasible" if it has been "demonstrated" or if it is both "available" and "applicable."

3.1.3 Step 3 – Rank Remaining Control Options

All remaining technically feasible control options are ranked based on their overall control effectiveness for the pollutant under review. If there is only one remaining option or if all the remaining technologies could achieve equivalent control efficiencies, ranking based on control efficiency is not required. Collateral effects are usually not considered until step four of the five step top-down RACT analysis.

3.1.4 Step 4 – Evaluation of Most Effective Control Option

After identifying and ranking available and technically feasible control technologies, the economic, environmental, and energy impacts are evaluated to select the best control option. If collateral impacts do not disqualify the top-ranked option from consideration, it is selected as the basis for the RACT limit. Alternatively, in the judgment of the permitting agency, if economic, environmental, or energy considerations impact the top control option, the next most stringent option is evaluated. This process continues until a control technology is identified. This step validates the suitability of the top control option identified or provides a clear justification as to why the top option should not be selected as RACT.

3.1.5 Step 5 – Select RACT

In the final step, the RACT is determined for each emission unit under review based on evaluations from the previous step.

4. NO_X TOP-DOWN RACT STUDY

4.1 Overview of Potentially Applicable NOx Control Technologies

NO_X control technologies can lower emissions by minimizing NO_X formation or reducing emissions to atmosphere after its generated. Thermal NO_X is formed through high temperature oxidation of nitrogen found in the combustion air. The rate at which NO_X is formed depends on the reaction temperature, nitrogen, and oxygen concentrations, as well as the residence time at a given temperature. The concentration of thermal NO_X can be controlled by regulating the nitrogen and oxygen molar concentrations as well as the combustion temperature. Fuel NO_X is formed by the reaction of burning fuels that contain nitrogen with oxygen in the combustion air. Fuel NO_X can be controlled by utilizing other types of fuels that contain lower nitrogen such as blast furnace gas, reducing flame temperatures as well as reducing excess oxygen. Lastly, prompt NO_X is formed during the early stages of combustion and occurs in the presence of hydrocarbon radicals in fuel rich flames.

This report provides a list of NO_X control measures that should be evaluated as part of the NO_X RACT study. However, not all of the listed control measures are applicable to the furnaces included in this RACT study. The following sections outline the potential applicability of each of the listed NO_X control measures to the emission units included in this study.

4.1.1 Close Coupled or Separated Over-Fire Ports

Close coupled or separated over-fire ports implement air staged combustion to create a fuel-rich mixture in the main combustion zone. Since the stoichiometric ratio between the combustion fuel and air is not proportional, the combustion temperature is reduced, which in turn lowers thermal NO_X formation. After all other stages of combustion take place, the excess air needed to complete combustion is admitted through over-fire ports mostly located above the highest level of burners in the furnaces. This control technology is applicable to combustion sources that burn all types of fuels and is generally applicable to boilers. However, new furnace penetrations are required to implement over-fire systems on existing furnaces. Accordingly, this approach could not be adapted to the affected sources and is therefore not applicable for this study.

4.1.2 Burners Out of Service (BOOS)

BOOS is a form of fuel staged combustion that reduces the formation of thermal NO_X by reducing combustion temperature. Staged combustion is achieved by having multiple burners out of service (i.e., not feeding fuel and instead supplying air or flue gas) and the balance of the fuel required to maintain the unit firing rate is achieved by the remaining burners. Some of the disadvantages of this technique include high CO emissions, potentially uneven temperature profiles, and oxygen imbalances. Due to the firing rates of the furnaces and the importance of even temperature profiles to ensure proper heating of products, this approach could not be adapted to the affected sources and is therefore not applicable for this study.

4.1.3 Flue Gas Recirculation (FGR)

Flue Gas Recirculation (FGR) is another type of NO_X control measure that reduces the formation of thermal NO_X by reducing combustion temperature. The flame temperature is lowered by recirculating cooled flue gas and diluting the oxygen content of the combustion air. FGR is not considered a reasonable control option due to the potential drawbacks (e.g., uneven temperature profiles which can affect product quality). Further, Cliffs is not aware of any FGR applications for annealing furnaces within the steel industry. Accordingly, FGR is not an available technology for review for the affected sources and is therefore not applicable for this study.

4.1.4 Low-NO_X Burners with External Flue Gas Recirculation

Low-NO_X burners with external flue gas recirculation use cooled flue gases from the exhaust stacks to dilute the combustion process. The inert compounds in the flue gas streams (nitrogen, water vapor, and carbon dioxide) serve as heat sinks and can reduce combustion temperature significantly. The flue gas that is mixed with the combustion air enters the burners using adapted pipes. Recirculating flue gas in the current system would require extensive modifications. Further, this control technology is not considered a reasonable control option due to its potential drawbacks (i.e., uneven temperature profiles). Accordingly, this technology could not be adapted to the affected sources and is therefore not applicable for this study.

4.1.5 Steam/Water Injection

Steam/water injection is a type of control measure whereby water or steam is injected into the combustion zone to lower the flame temperature. However, this technology results in a significant energy loss due to the amount of energy required to produce the steam (if steam injection is used). Further, fuel consumption also increases to account for the heat of vaporization of water.

4.1.6 Dry Low NO_X Burners

Dry low NO_X burners are special types of burners used to reduce NO_X emissions from gas-fired turbines. The configuration of this control technology is only suitable for gas turbines. Cleveland-Cliffs does not operate emission sources for which this technology is applicable; as such, this control measure if not applicable for this study.

4.1.7 Ignition Timing Retard

Internal combustion engines use ignition timing to control maximum temperature and residence time. This control measure is not applicable for any of the affected sources included in this RACT study.

4.1.8 Adjustment of Air/Fuel Ratio (for internal combustion engines only)

Internal combustion engines use air-to-fuel ratio to control maximum temperature and residence time, resulting in lower NO_X emissions. This control measure is not applicable for any of the affected sources included in this RACT study.

4.1.9 Fuel Emulsification

Fuel emulsification is a type of NO_X control technology whereby thermal NO_X generation is reduced by decreasing the combustion temperatures. Reduction in combustion temperatures is achieved by injecting water into the liquid fuels burned in the combustion sources. This control measure is not applicable for any of the affected sources included in this RACT study.

4.1.10 Separate Circuit After-Cooling

This control technology is applicable to internal combustion engines and works by adding a separate water circuit to cool the engine’s intake air. This control measure is not applicable for any of the affected sources included in this RACT study.

4.1.11 Non-Selective Catalytic Reduction (NSCR)

NSCR is an add-on NO_X control technology which uses catalysts to reduce NO_X emissions from internal combustion engines. To achieve optimum NO_X reduction, the oxygen content of the exhaust streams must be low. This control measure is not applicable for any of the affected sources included in this RACT study.

4.1.12 Incineration (for sources other than boilers)

Incinerators are typically used to control emissions from facilities that operate paint lines or have hazardous waste. Cleveland-Cliffs does not operate sources for which this technology can be applied; as such, this control measure is not applicable for this study.

4.1.13 Scrubbing (for sources other than boilers)

Wet scrubbers can control NO_X emissions from pickling operations using alkali in water, water alone, or hydrogen peroxide as the liquid that captures NO_X. This control measure is not applicable for any of the affected sources included in this RACT study.

4.1.14 Process Modification

Process modification is not a feasible control option for CCGP and therefore not applicable for any of the affected sources included in this RACT study.

4.1.15 Low Excess Air (LEA)

LEA is a type of control measure whereby the net excess air flow is limited to reduce combustion temperature and oxygen availability, minimizing potential NO_X formation. Even though LEA is applicable to combustion sources that burn all types of fuels, insufficient air supply can result in lower combustion efficiency due to incomplete combustion and thus increased CO emissions. Further, LEA can also lead to uneven temperature profiles and heat distribution, which are critical parameters that affect the quality of Cleveland-Cliffs' products. Due to the preceding justification, this technology could not be adapted to the affected sources and is therefore not applicable for this study.

4.1.16 Gaseous Fuels Reburn

Fuel reburning is a NO_X control measure whereby cooled flue gas mixed with added fuel is injected back into the main combustion zone for chemical reduction of NO_X to thermal nitrogen. In addition to chemically reducing NOx, the primary combustion temperature is lowered, reducing thermal NO_X formation. However, this control measure could affect furnace temperature profiles, an important parameter that can adversely impact the quality of Cleveland-Cliffs' products. Accordingly, this technology could not be adapted to the affected sources and is therefore not applicable for this study.

4.1.17 Mid-kiln Firing

In mid-kiln firing, fuel is added in the main flame at mid-kiln, which changes both the flame temperature and flame length. These changes can reduce thermal NO_X formation by burning part of the fuel at a lower temperature. This control measure is not applicable for any of the affected sources included in this RACT study.

4.1.18 Mid-kiln Air Injection

This control measure is not applicable for any of the affected sources included in this RACT study.

4.1.19 Low NOx Burners (LNB)

LNBs implement fuel or air staging to reduce combustion temperatures and lower thermal NO_X formation. Air staging in the primary combustion zone creates "fuel-rich" combustion zones where the formation of NO_X is disrupted due to lack of oxygen and reduced combustion temperature. The additional air required for complete combustion is supplied outside the main combustion zone. Fuel staging works the opposite of air staging whereby the primary combustion zone is "fuel-lean". Under this condition, thermal NO_X formation is lowered due to reduced combustion temperatures. Similar to air staging, the additional fuel required for complete combustion to take place is supplied downstream of the primary combustion zone. LNBs are potentially applicable and are the current control measures for some of the affected sources; as such, this control measure is included for consideration in this study.

4.1.20 Selective Catalytic Reduction (SCR)

SCR is a post combustion, add-on control technology in which ammonia is injected into the flue gas streams upstream of the catalyst bed to reduce NO_X into elemental nitrogen and water. SCR systems employ metal-based catalysts with activated sites to increase the reduction rate of NO_X. Critical parameters which affect the reduction rate of NO_X include reaction temperature range, residence time available in the optimum temperature range, molar ratio of injected ammonia to uncontrolled NO_X, degree of mixing between ammonia and NO_X, and ammonia slip. The reaction temperature for the reduction reaction ranges between 480-800 °F with optimum NO_X removal occurring at approximately 700 °F. Efficient SCR systems require stable flue gas streams in regard to temperature, flow rate, and NO_X concentrations. If designed and operated efficiently, SCR systems can reduce NO_X emissions by 70% - 90%.[2] SCR is potentially applicable to the affected sources; as such, this control measure is included for consideration in this study.

4.1.21 Selective Noncatalytic Reduction (SNCR)

Similar to SCR systems, SNCR is a type of post combustion, add-on NO_X emissions control technology whereby ammonia or urea is injected into the combustion source to reduce NO_X into elemental nitrogen and oxygen. The key difference between SCR and SNCR is that SCR uses a catalyst for the reduction reaction to take place. However, for SNCR systems to be effective, the ammonia or urea must be injected into a region with a narrow temperature range (usually 1600–2100 °F). Different factors such as temperature, residence time, type of reducing agent, reagent injection rate, uncontrolled NOx level affect the reduction potential of this technology. The reaction temperature is critical since heat is needed to drive the reaction. At lower temperatures, reaction kinetics are slow, resulting in potential ammonia slip. At higher temperatures, ammonia oxidizes resulting in additional NO_X formation. If designed and operated efficiently, SNCR systems can reduce NOx emissions by 70% - 90.[3] SNCR is potentially applicable to the remaining sources. As such, this control measure is included for consideration in this study.

4.1.22 Fuel Switching

The order of fuels based on highest NO_X emissions is coal, oil, NG, and BFG. All affected annealing furnaces at CCGP burn natural gas exclusively, which has the second lowest NO_X emissions after BFG. Accordingly, fuel switching is not an option considered in this study.

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[2] U.S. EPA Cost Control Manual, 2002. https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual.

[3] *Ibid*

4.2 Annealing Furnaces

Steel plate operations at CCGP include four (4) annealing furnaces: two NG-fired hardening furnaces (north and south) and two tempering furnaces (north and south). Each annealing furnace has an estimated nominal capacity of 100 MMBtu/hr heat input.

As described in the current Title V permit, all annealing furnaces vent to roof monitors, not to a stack. Each of these units have approximately 155-160 burners that vent to approximately 40 different exhaust points within the respective building.

4.2.1 Step 1 – Identify All Control Options

CCGP considers the following technologies to be generally available for controlling NO_X emissions from the annealing furnaces:

- SCR / SNCR
- LNB

4.2.2 Step 2 – Eliminate Technically Infeasible Options

4.2.2.1 SCR / SNCR

As stated above, NO_X emissions from each of these furnaces are vented to approximately 40 different exhaust points within the respective building. Therefore, add-on control devices are technically infeasible since NO_X emissions are fugitive in nature.

4.2.2.2 LNBs

LNBs or ultra low-NO_X burners (ULNBs) are technically feasible control options for the annealing furnaces. As stated above, each of these units have approximately 155-160 burners.

4.2.3 Step 3 – Rank Remaining Control Options

The technically feasible option for controlling NO_X emissions from the annealing furnaces are as follows:

Table 4-1. Remaining Control Options

Emission Unit	NOx Removal Technology	Expected Removal Efficiency
Hardening Furnaces	LNBs/ULNBs	Variable
Tempering Furnaces	LNBs/ULNBs	Variable

4.2.4 Step 4 – Evaluation of Most Effective Control Option

Due to the time constraint of the request from IDEM, CCGP was unable to obtain unit-specific quotes from Bloom Engineering (Bloom) to replace the existing Bloom burners in the two hardening furnaces and two tempering furnaces. However, CCGP has received vendor quotes from Bloom for other Cleveland-Cliffs facilities in Indiana and Ohio. Based on these quotes, new LNBs/ULNBs that are capable of meeting the presumptive RACT limit of 0.09 lb NO_X/MMBtu range from approximately $5,000 to $8,500 per burner.

Thus, CCGP has estimated the Purchased Equipment Cost (PEC) for each unit at a minimum value of $775,000. CCGP has used nominal values for engineering/design and installation costs as 10% of PEC and 35% of PEC, respectively. The detailed cost calculations are provided in Appendix A.

Table 4-2. Cost-Effectiveness of Installing LNBs in Annealing Furnaces (PTE Basis)

Emission Unit	LNB	Total Capital Investment	Total Annualized Costs	NOx removed (tpy)	Cost Effectiveness ($/ton)
Hardening Furnace (Each)	Bloom	$ 1,123,750	$ 180,272	3.52	$ 51,213.78
Tempering Furnace (Each)	Bloom	$ 1,123,750	$ 180,272	3.52	$ 51,213.78

As shown in the above table, it is economically unreasonable to install LNBs in the annealing furnaces.

4.2.5 Step 5 – Select RACT

Since there are no control devices, including LNBs, that are both technically feasible and cost-effective, CCGP proposes the following operational restrictions as RACT:

1. Limit the fuel used in the annealing furnaces to NG only.
2. Install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices for the control of the NO_X emissions from the unit.

Note that Cleveland-Cliffs has not proposed a numerical limit for NO_X RACT. As is evident by the process description, it is not feasible to perform a stack test on the annealing furnaces. Thus, there is no baseline emissions test from which a numerical short-term lb NO_X/MMBtu emission limit could be derived.

5. SUMMARY OF RACT DETERMINATIONS

A summary of the proposed RACT determinations for each source is presented in Table 5-1 below.

Table 5-1. Summary of Proposed RACT Determinations

Emission Unit IDs	Description	Proposed RACT Determination
24-27	Annealing Furnaces – two NG-fired hardening furnaces and two NG-fired tempering furnaces.	• Limit the fuel used to NG only • Operate and maintain all annealing furnaces in accordance with good combustion practices and manufacturers recommendations

APPENDIX A. COST CALCULATIONS

Estimated Average Cost ($/ton) of Burner Installation

For Hardening Furnace (North or South) or Tempering Furnace (North or South)

ASSUMPTIONS

Parameter	Value	Units	Basis
Cost Year	2024		
Equipment Life	15	yrs	US EPA OAQPS
Annual Interest Rate	8.5	%	https://www.federalreserve.gov/releases/h15/

NO_X REDUCTION CALCULATIONS

Parameter	Value	Units	Basis
NO_X Removed (PTE Basis)	3.52	tons/yr	Maximum capacity, assuming 8,760 hr/yr of operation and multiplied by the delta of baseline and new emission factors
Furnace Capacity	100	MMBtu/hr	Title V Permit Basis
Baseline Emission Factor	0.098	lb NO_X/MMBtu	AP-42, Table 1.4-1, NG Combustion, 5th Ed, 7/98
New Emission Factor	0.09	lb NO_X/MMBtu	Proposed Presumptive NO_X RACT Limit

TOTAL CAPITAL INVESTMENT

Parameter	Value	Basis
Purchased Equipment Cost	$ 775,000	Approx. $5,000/burner x 155 burners per discussions with Bloom Eng regarding similar units at CCIH and CCBH
Engineering/Supervision Cost	$ 77,500	Conservative estimate of 10% of PEC
Installation Cost	$ 271,250	Estimated approximately 35% of PEC per vendor recommendation
Total Capital Investment, TCI	$ 1,123,750	PEC + Installation + Engineering / Supervision Cost

TOTAL ANNUAL COSTS

Parameter	Value	Basis
Direct Annual Costs		
Annual Maintenance Costs	$ -	
Annual Operator Labor Cost	$ -	
Total direct annual cost, DAC	$ -	
Indirect Annual Costs		
Annual Administrative Cost	$ 22,475	2% of TCI
Property Tax	$ 11,238	1% of TCI
Insurance	$ 11,238	1% of TCI
IDAC and TAC		
Capital Recovery, CR	$ 135,322	CR = CRF x TCI
Capital recovery factor, CRF	0.1204	CRF = i (1+ i)n/(1+ i)n - 1; where n = Equipment Life and i= Interest Rate
Total Indirect Annual Costs, IDAC	$ 180,272	IDAC = sum of Annual Administrative Cost Property Tax Insurance Capital Recovery, CR
Total Annual Cost, TAC	**$ 180,272**	**TAC = DAC + IDAC**

COST EFFECTIVENESS

Annual Cost (NO_X removed)	Value	Units	Basis
PTE Basis	$ 51,213.78	$/ton	TAC/NO_X Removed

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APPENDIX A-5

Source ID#s 089-00316 & 089-00318

Cleveland-Cliffs Steel, LLC-Indiana Harbor Facility

NOx RACT Study

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NO$_X$ REASONABLY AVAILABLE CONTROL TECHNOLOGY STUDY

Cleveland-Cliffs Steel LLC. – Indiana Harbor | East Chicago, Indiana

Prepared By:

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1. EXECUTIVE SUMMARY

Cleveland-Cliffs Steel LLC (Cleveland-Cliffs) owns and operates an integrated steelmaking facility located in East Chicago, Lake County, Indiana (CCIH), consisting of the following NO_X emitting units:

- Blast Furnace Stoves
- Blast Furnace Cast Houses
- Blast Furnace Flares
- Basic Oxygen Furnaces
- Continuous Casters
- Galvanizing Lines
- Galvanizing Lines Flame Furnaces
- Boilers
- Recycle Plant Strand Combustion
- Lime Plant Kilns
- Hot Strip Mills
- Annealing Furnaces
- Miscellaneous Fuel Combustion (e.g. Ladle Preheaters etc.)

To support development of a State Implementation Plan (SIP) for meeting the 2015 8-hour ozone National Ambient Air Quality Standards (NAAQS) in the "moderate" nonattainment areas of Lake and Porter counties, the Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ), requested a NO_X Reasonably Available Control Technology (RACT) analysis for the units at CCIH. The following submittal reflects CCIH's RACT analysis in response to this request. Given that CCIH has only had a limited amount of time to prepare this response, we may supplement our response as needed as the rulemaking process proceeds forward.

2. FACILITY OVERVIEW

2.1 General Facility Information

The Indiana Harbor (CCIH) is an integrated steelmaking facility [standard industrial classification (SIC) code: 3312] located at 3210 Watling Street (Indiana Harbor West Facility or "CCIHW") and 3001 Dickey Road (Indiana Harbor East Facility or "CCIHE"), East Chicago, Indiana 46312. CCIHE currently operates under Title V operating permit No. 089-44076-00316, last modified by administrative amendment No. 089-46648-00316. A renewal application for the CCIHE's Title V Operating Permit was submitted to IDEM on March 27, 2023, and is currently being processed. CCIHW currently operates under Title V operating permit No. 089-38318-00318, last modified by administrative amendment No. 089-45753-00318. A renewal application for CCIHW's Title V Operating Permit was submitted to IDEM on March 27, 2023, and is currently being processed.

On July 8, 2024, IDEM notified Cleveland-Cliffs that Indiana plans to follow Ohio's lead by using Ohio's proposed RACT rules. Citations below reference sections of the Ohio Administrative Code (OAC) associated with RACT.

Figure 2-**1** is an area map that shows the site location relative to predominant geographical features such as highways and railroads.

Facility information required by sections (a) through (d) of OAC 3745-110-03(J)(1) is provided as follows:

(a) The complete facility name, IDEM air quality permit source ID, and address:

Cleveland-Cliffs Steel LLC
089-00316 and 089-00318
3210 Watling Street and 3001 Dickey Road
East Chicago, Indiana 46312

(b) The name, title, address and telephone number of the owner or operator's representative within the company who is the contact person for this facility regarding the RACT study and affected sources:

Brian Wolters
Lead Environmental Air Engineer – Indiana Harbor Works
3210 Watling Street and 3001 Dickey Road
East Chicago, IN 46312
(219) 399-7000

(c) The name, title, address and telephone number of the official who is responsible for approval of the RACT study:

LaDale Combs
Sr. General Manager – Indiana Harbor Works
3210 Watling Street and 3001 Dickey Road
East Chicago, IN 46312
(219) 399-7000

Figure 2-1. Area Map of Indiana Harbor

2.2 Permitted NO_X Sources

Table 2-1 summarizes the Title V permitted NO_X sources at CCIH that are subject to either presumptive RACT limits and/or a detailed RACT study.

Table 2-2 provides the Title V permitted NO_X sources that are exempt from the NO_X RACT regulations and are therefore not considered in the remainder of this NO_X RACT study. The justifications for exclusion from the RACT regulations are provided therein. Specifically, based on guidance from IDEM, CCIH assumes that units with a potential to emit (PTE) of less than 25 tons per year (tpy) of NO_X are exempt from the RACT Analysis pursuant to the RACT exemptions from Ohio EPA in the Ohio Administrative Code 3745-110-03(K)(16).

Table 2-1. Summary of Permitted NO_X Sources Subject to RACT Regulations

Emission Unit Description	Rated Capacity		Fuels Burned	NO_X PTE (tpy)	Current NO_X Emission Limit(s)	NO_X RACT Applicability
Blast Furnace IH7 Stoves (includes casthouses and flare)	953	MMBtu/hr	BFG / NG [a]	736	n/a	RACT Study
Recycle Plant Strand Combustion	1,400,000	tpy	-	210	n/a	RACT Study
No. 4 BOF #50 and #60 Furnaces (primary & sec. vent)	4,686,600	tpy	-	129	n/a	RACT Study
No. 1 Lime Plant No. 1 Kiln	284	MMBtu/hr	NG / Oil [b]	17,331	n/a	RACT Study
No. 2 Lime Plant No. 2 Kiln	284	MMBtu/hr	NG / Oil [b]	17,331	n/a	RACT Study
80" Hot Strip Mill #4 WBF	720	MMBtu/hr	NG	480,500	357 lb/MMCF	Presumptive RACT
80" Hot Strip Mill #5 WBF	685.6	MMBtu/hr	NG	491,775	n/a	Presumptive RACT
80" Hot Strip Mill #6 WBF	685.6	MMBtu/hr	NG	491,775	n/a	Presumptive RACT
No 6 Batch Annealing Furnaces (combined) 17 Multi-stack, 8 Single-stack, 1 H2/Single-stack Units	288 Total	MMBtu/hr	NG	123 Total	0.2 lb/MMBtu (20.19 tpy)	Presumptive RACT
3 Continuous Annealing Line (CAL)	108	MMBtu/hr	NG	176	n/a	Presumptive RACT
No. 5 Boiler House: 501-503 Boilers	520 each, (10% NG, max)	MMBtu/hr each	NG [a] BFG	23 each 172 each	50% BFG, Ozone Season 0.17 lb/MMBtu - BFG	Presumptive RACT
No. 5 Boiler House: 504 Boiler	561.6	MMBtu/hr	NG [a] BFG	25 173	50% BFG, Ozone Season 0.17 lb/MMBtu - BFG	Presumptive RACT
Blast Furnace IH3 Stoves	441	MMBtu/hr	BFG / NG [a]	33	n/a	RACT Study
Blast Furnace IH3 Casthouse	4,555,200	tpy	-	25	n/a	RACT Study
Blast Furnace IH4 Stoves	486	MMBtu/hr	BFG / NG [a]	36	n/a	RACT Study
Blast Furnace IH4 Casthouse	5,490,836	tpy	-	30	n/a	RACT Study
No. 3 BOF #1 and #2 Furnaces	7,456,512	tpy	-	1,184	n/a	RACT Study
2SM No 2 Galvanizing Line Radiant Tube Furnace	49.65	MMBtu/hr	NG	37	n/a	RACT Study
2SM No 2 Galvanizing Line Flame Furnace	150	MMBtu/hr	NG	64	n/a	Presumptive RACT
West Utilities Boiler House: #6 Boiler (NG/BFG)	454	MMBtu/hr	NG BFG	153 14	50% BFG, Ozone Season 0.17 lb/MMBtu - BFG	Presumptive RACT
West Utilities Boiler House: #7 Boiler (NG/BFG)	454	MMBtu/hr	NG BFG	153 14	50% BFG, Ozone Season 0.17 lb/MMBtu - BFG	Presumptive RACT
West Utilities Boiler House: #8 Boiler (NG/BFG)	1,090	MMBtu/hr	NG BFG	393 34	50% BFG, Ozone Season 0.17 lb/MMBtu - BFG	Presumptive RACT

[a] These units predominantly use blast furnace gas (BFG). Natural gas (NG) is used for pilots and supplementary fuel when necessary (approx. 8% of fuel load).

[b] These units use a mixture of NG and oil (70% / 30% respectively).

Table 2-2. Summary of Permitted NO_X Sources Exempt from RACT Regulations

Emission Unit Description	Exemption Justification
IH7 Blast Furnace Casthouse Roof Monitor	PTE < 25 tpy
IH7 Slag Pits	PTE < 25 tpy
IH7 PCI Baghouses D & E Grinders/Dryers	PTE < 25 tpy
No. 2 BOF Charge Aisle	PTE < 25 tpy
No. 2 BOF ROOF Monitor	PTE < 25 tpy
No. 2 BOF LMF Ladle Metal	PTE < 25 tpy
No. 3 BOF RH Condenser Flare	PTE < 25 tpy
Continuous Casters	Refer to Text Below
No. 4 BOF Hot Metal Pit	PTE < 25 tpy
No. 4 BOF Ladle Preheat	PTE < 25 tpy
No. 4 BOF RHOB Condenser Flare	PTE < 25 tpy
IH3 Slag Pit	PTE < 25 tpy
IH4 Slag Pit	PTE < 25 tpy
IH3 Excess Gas Flare	PTE < 25 tpy
IH4 Excess Gas Flare	PTE < 25 tpy
BF Ladle Burners	PTE < 25 tpy
Thaw Shed Heater	PTE < 25 tpy
2SM Space Heaters	PTE < 25 tpy
NG Emergency Engines	PTE < 25 tpy
Diesel Emergency Engines	PTE < 25 tpy
3SP Fuel Usage (Ladle Preheaters, etc.)	PTE < 25 tpy
4SP Fuel Usage (Ladle Preheaters, etc.)	PTE < 25 tpy
Pugh Ladle Lancing and Drying, (each)	PTE < 25 tpy

Continuous Casters

Molten metal is poured from ladle into the continuous casters, where the metal passes through molds to form specific shapes (e.g., slabs). The only fuel used in these units is the NG for the torch that "cuts" the slab from the end of the continuous caster stand.

CCIH has historically calculated NO_X emissions from this process using an emission factor of 0.05 lb/ton metal, taken from the ACT Document for Iron and Steel Mills and resulting in a PTE NO_X of greater than 25 tpy. As noted in Table 4-3. Footnote b. of said document, "These factors have an E quality rating. Thus, they are based on a single observation of questionable quality or extrapolated from another factor for a similar process." The 0.05 lb NO_X/ton metal represents the amount of NO_X theoretically generated from exposure of molten metal to nitrogen in the atmosphere. To create the steel products at CCIH, however, mold powder is used to limit or negate the exposure of molten steel to atmospheric nitrogen. Thus, there should be little to no NO_X formation other than from the small burners used as torch cutters. Therefore, it is determined that the continuous casters are exempt from RACT requirements.

3. PRESUMPTIVE LIMITS

The NO_X RACT regulations specify presumptive NO_X emission limits for the following source types:

- Boilers and process heaters
- Stationary combustion turbines
- Stationary internal combustion engines
- Iron and steel production sources (reheat, annealing, and galvanizing furnaces > 75 MMBtu/hr)

CCIH operates seven boilers, three reheat furnaces, two annealing operations, and one galvanizing line at CCIH (i.e., CCIHW and CCIHE) that meet the criteria described above and are potentially subject to the presumptive NO_X emission limits. The emission unit category and presumptive NO_X emission limit for the affected units are summarized in Table 3-1.

Table 3-1. Presumptive NO_X RACT Limits for Affected Units

Emission Unit Description	Rated Capacity (MMBtu/hr)	Fuels Burned	EU Classification	Presumptive NO_X Limit (lb/MMBtu)
80" Hot Strip Mill #4 WBF	720	NG	Reheat Furnace	0.09
80" Hot Strip Mill #5 WBF	685.6	NG	Reheat Furnace	0.09
80" Hot Strip Mill #6 WBF	685.6	NG	Reheat Furnace	0.09
No 6 Batch Annealing Furnace	205	NG	Annealing Furnace	0.09
No. 3 Continuous Annealing Line (CAL)	108	NG	Annealing Furnace	0.09
No. 2 Galvanizing Line, Direct- and Indirect-Fired Furnaces	200	NG	Galvanizing Furnace	0.09
Boiler 501	520	NG	Boiler	0.08
Boiler 502	520	NG	Boiler	0.08
Boiler 503	520	NG	Boiler	0.08
Boiler 504	561.6	NG	Boiler	0.08
#6 Boiler	454	NG	Boiler	0.08
#7 Boiler	454	NG	Boiler	0.08
#8 Boiler	1090	NG	Boiler	0.08

For all of the units listed above, CCIH has provided information within this analysis as to why meeting the presumptive RACT limits are either not technically feasible or not cost-effective.

4. RACT DEFINITION AND METHODOLOGY

"RACT," "BACT," and "LAER" are acronyms for different levels of emissions control. The least stringent is RACT, more stringent is BACT, and the most stringent is LAER. The type of control required depends on the size of the stationary source and whether it is located in an attainment or nonattainment area.

- RACT, or Reasonably Available Control Technology, is required for major sources of NO_X in the 2015 8-hour ozone NAA.
- BACT, or Best Available Control Technology, is required for new major stationary sources and major modifications in attainment areas subject to Prevention of Significant Deterioration (PSD) permitting requirements.
- LAER, or Lowest Achievable Emission Rate, is required for new major stationary sources and major modifications in non-attainment areas subject to Nonattainment New Source Review permitting requirements.

At the federal level, RACT is not defined by statue or rule, rather it is defined in U.S. Environmental Protection Agency's (U.S. EPA) guidance 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."[1]

Considering this definition, RACT involves identifying implementable control technologies with due consideration given to technological and economic feasibility. Since RACT considers the technological and economic impacts of controls, the analysis and determination may differ from source to source and location to location.

4.1 Top-down Approach

In this RACT study, CCIH is using the U.S. EPA's top-down approach to determining the feasibility of control technology where the most stringent control available for a similar or identical source or source category is identified. This control option is used to establish the RACT emission limitation, unless the applicant can demonstrate (and the permitting authority agrees) that it is not "achievable" due to technical infeasibility or not being cost effective and potentially having other adverse environmental or energy consequences of implementing the technology. If the top control alternative is eliminated, then the next most stringent level of control is evaluated. This process continues until RACT is selected. The five steps in a top-down RACT evaluation can be summarized as follows:

- Step 1. Identify all possible control technologies
- Step 2. Eliminate technically infeasible options
- Step 3. Rank the technically feasible control technologies based upon emission reduction potential
- Step 4. Evaluate ranked controls based on energy, environmental, and/or economic considerations
- Step 5. Select RACT

The following sections contain a description of the five (5) basic steps of this "top-down" approach.

[1] 44 Fed. Reg. 53762 (9/17/1979)

4.1.1 Step 1 – Identify All Control Options

In this step, available control technologies with the practical potential for application to the emission unit and regulated air pollutant in question are identified. The selected control technologies vary widely depending on the process technology and pollutant being controlled. The application of demonstrated control technologies in other similar source categories to the emission unit in question may also be considered in this step.

The following resources are typically consulted when identifying potential technologies for criteria pollutants:

- EPA's RACT/BACT/LAER Clearinghouse (RBLC) database
- NSPS, NESHAP, and RACT regulations for similar operations
- Engineering experience with similar control applications
- Information provided by air pollution control equipment vendors with significant market share in the industry

4.1.2 Step 2 – Eliminate Technically Infeasible Options

In this step, "technically infeasible" control options from the list of "potentially available" control options are eliminated. A control option is "technically feasible" if it has been "demonstrated" or if it is both "available" and "applicable."

4.1.3 Step 3 – Rank Remaining Control Options

All remaining technically feasible control options are ranked based on their overall control effectiveness for the pollutant under review. If there is only one remaining option or if all the remaining technologies could achieve equivalent control efficiencies, ranking based on control efficiency is not required. Collateral effects are usually not considered until step four of the five step top-down RACT analysis.

4.1.4 Step 4 – Evaluation of Most Effective Control Option

After identifying and ranking available and technically feasible control technologies, the economic, environmental, and energy impacts are evaluated to select the best control option. If collateral impacts do not disqualify the top-ranked option from consideration, it is selected as the basis for the RACT limit. Alternatively, in the judgment of the permitting agency, if economic, environmental, or energy considerations impact the top control option, the next most stringent option is evaluated. This process continues until a control technology is identified. This step validates the suitability of the top control option identified or provides a clear justification as to why the top option should not be selected as RACT.

4.1.5 Step 5 – Select RACT

In the final step, the RACT is determined for each emission unit under review based on evaluations from the previous step.

5. NO_X TOP-DOWN RACT STUDY

5.1 Overview of Potentially Applicable NO_X Control Technologies

NO_X control technologies can lower emissions by minimizing NO_X formation or reducing emissions to atmosphere after its generated. Thermal NO_X is formed through high temperature oxidation of nitrogen found in the combustion air. The rate at which NO_X is formed depends on the reaction temperature, nitrogen, and oxygen concentrations, as well as the residence time at a given temperature. The concentration of thermal NO_X can be controlled by regulating the nitrogen and oxygen molar concentrations as well as the combustion temperature. Fuel NO_X is formed by the reaction of burning fuels that contain nitrogen with oxygen in the combustion air. Fuel NO_X can be controlled by utilizing other types of fuels that contain lower nitrogen such as BFG, reducing flame temperatures as well as reducing excess oxygen. Lastly, prompt NO_X is formed during the early stages of combustion and occurs in the presence of hydrocarbon radicals in fuel rich flames.

OAC 3745-110-03(J)(1)(h) provides a list of at least 22 NO_X control measures that should be evaluated as part of the NO_X RACT study. However, not all of the listed control measures are applicable to the furnaces included in this RACT study. The following sections outline the potential applicability of each of the listed NO_X control measures to the emission units included in this study.

5.1.1 Close Coupled or Separated Over-Fire Ports

Close coupled or separated over-fire ports implement air staged combustion to create a fuel-rich mixture in the main combustion zone. Since the stoichiometric ratio between the combustion fuel and air is not proportional, the combustion temperature is reduced, which in turn lowers thermal NO_X formation. After all other stages of combustion take place, the excess air needed to complete combustion is admitted through over-fire ports mostly located above the highest level of burners in the furnaces. This control technology is applicable to combustion sources that burn all types of fuels and is generally applicable to boilers. However, new furnace penetrations are required to implement over-fire systems on existing furnaces. Based on the information available at the time of submitting this RACT analysis, close coupled or separated over-fire ports are not assessed as a viable mechanism for NO_X mitigation for the subject units at CCIH.

5.1.2 Burners Out of Service (BOOS)

BOOS is a form of fuel staged combustion that reduces the formation of thermal NO_X by reducing combustion temperature. Staged combustion is achieved by having multiple burners out of service (i.e., not feeding fuel and instead supplying air or flue gas) and the balance of the fuel required to maintain the unit firing rate is achieved by the remaining burners. Some of the disadvantages of this technique include high CO emissions, potentially uneven temperature profiles, and oxygen imbalances. Based on the information available at the time of submitting this RACT analysis, BOOS is not assessed as a viable mechanism for NO_X mitigation for the subject units at CCIH.

5.1.3 Flue Gas Recirculation (FGR)

Flue Gas Recirculation (FGR) is another type of NO_X control measure that reduces the formation of thermal NO_X by reducing combustion temperature. The flame temperature is lowered by recirculating cooled flue gas and diluting the oxygen content of the combustion air.

5.1.4 Low-NO_X Burners with External Flue Gas Recirculation

Low-NO_X burners with external flue gas recirculation use cooled flue gases from the exhaust stacks to dilute the combustion process. The inert compounds in the flue gas streams (nitrogen, water vapor, and carbon dioxide) serve as heat sinks and can reduce combustion temperature significantly. The flue gas that is mixed with the combustion air enters the burners using adapted pipes.

5.1.5 Steam/Water Injection

Steam/water injection is a type of control measure whereby water or steam is injected into the combustion zone to lower the flame temperature. However, this technology results in a significant energy loss due to the amount of energy required to produce the steam (if steam injection is used). Further, fuel consumption also increases to account for the heat of vaporization of water. Based on the information available at the time of submitting this RACT analysis, steam/water injection is not assessed as a viable mechanism for NO_X mitigation for the subject units at CCIH.

5.1.6 Dry Low NO_X Burners

Dry low NO_X burners are special types of burners used to reduce NO_X emissions from gas-fired turbines. The configuration of this control technology is only suitable for gas turbines. CCIH does not operate emission sources for which this technology is applicable; as such, this control measure if not applicable for this study.

5.1.7 Ignition Timing Retard

Internal combustion engines use ignition timing to control maximum temperature and residence time. This control measure is not applicable for any of the affected sources included in this RACT study.

5.1.8 Adjustment of Air/Fuel Ratio (for internal combustion engines only)

Internal combustion engines use air-to-fuel ratio to control maximum temperature and residence time, resulting in lower NO_X emissions. This control measure is not applicable for any of the affected sources included in this RACT study.

5.1.9 Fuel Emulsification

Fuel emulsification is a type of NO_X control technology whereby thermal NO_X generation is reduced by decreasing the combustion temperatures. Reduction in combustion temperatures is achieved by injecting water into the liquid fuels burned in the combustion sources. This control measure is not applicable for any of the affected sources included in this RACT study.

5.1.10 Separate Circuit After-Cooling

This control technology is applicable to internal combustion engines and works by adding a separate water circuit to cool the engine's intake air. This control measure is not applicable for any of the affected sources included in this RACT study.

5.1.11 Non-Selective Catalytic Reduction (NSCR)

NSCR is an add-on NO_X control technology which uses catalysts to reduce NO_X emissions from internal combustion engines. To achieve optimum NO_X reduction, the oxygen content of the exhaust streams must be low. This control measure is not applicable for any of the affected sources included in this RACT study.

5.1.12 Incineration (for sources other than boilers)

Incinerators are typically used to control emissions from facilities that operate paint lines or have hazardous waste. CCIH does not operate sources for which this technology can be applied; as such, this control measure is not applicable for this study.

5.1.13 Scrubbing (for sources other than boilers)

Wet scrubbers can control NO_X emissions from pickling operations using alkali in water, water alone, or hydrogen peroxide as the liquid that captures NO_X. This control measure is not applicable for any of the affected sources included in this RACT study.

5.1.14 Process Modification

Process modification is not a feasible control option for the Indiana Harbor Facilities and therefore not applicable for any of the affected sources included in this RACT study.

5.1.15 Low Excess Air (LEA)

LEA is a type of control measure whereby the net excess air flow is limited to reduce combustion temperature and oxygen availability, minimizing potential NO_X formation. Even though LEA is applicable to combustion sources that burn all types of fuels, insufficient air supply can result in lower combustion efficiency due to incomplete combustion and thus increased CO emissions. Further, LEA can also lead to uneven temperature profiles and heat distribution, which are critical parameters that affect the quality of CCIH' products. Due to the preceding justification, this technology could not be adapted to the affected sources and is therefore not applicable for this study.

5.1.16 Gaseous Fuels Reburn

Fuel reburning is a NO_X control measure whereby cooled flue gas mixed with added fuel is injected back into the main combustion zone for chemical reduction of NO_X to thermal nitrogen. In addition to chemically reducing NOX, the primary combustion temperature is lowered, reducing thermal NO_X formation. However, this control measure could affect furnace temperature profiles, an important parameter that can adversely impact the quality of CCIH' products. Accordingly, this technology could not be adapted to the affected sources and is therefore not applicable for this study.

5.1.17 Mid-kiln Firing

In mid-kiln firing, fuel is added in the main flame at mid-kiln, which changes both the flame temperature and flame length. These changes can reduce thermal NO_X formation by burning part of the fuel at a lower temperature. Based on the information available at the time of submitting this RACT analysis, mid-kiln firing is not assessed as a viable mechanism for NO_X mitigation for the subject units at CCIH.

5.1.18 Mid-kiln Air Injection

Based on the information available at the time of submitting this RACT analysis, mid-kiln air injection is not assessed as a viable mechanism for NO_X mitigation for the subject units at CCIH.

5.1.19 Low NO_X Burners (LNB)

LNBs implement fuel or air staging to reduce combustion temperatures and lower thermal NO_X formation. Air staging in the primary combustion zone creates "fuel-rich" combustion zones where the formation of NO_X

is disrupted due to lack of oxygen and reduced combustion temperature. The additional air required for complete combustion is supplied outside the main combustion zone. Fuel staging works the opposite of air staging whereby the primary combustion zone is "fuel-lean". Similar to air staging, the additional fuel required for complete combustion to take place is supplied downstream of the primary combustion zone. In either case, the staging effect creates a longer and cooler flame in the LNBs where thermal NO_X formation is decreased compared to traditional burners. LNBs are potentially applicable and are the current control measures for some of the affected sources; as such, this control measure is included for consideration in this study.

5.1.20 Selective Catalytic Reduction (SCR)

SCR is a post combustion, add-on control technology in which ammonia is injected into the flue gas streams upstream of the catalyst bed to reduce NO_X into elemental nitrogen and water. SCR systems employ metal-based catalysts with activated sites to increase the reduction rate of NO_X. Critical parameters which affect the reduction rate of NO_X include reaction temperature range, residence time available in the optimum temperature range, molar ratio of injected ammonia to uncontrolled NO_X, degree of mixing between ammonia and NO_X, and ammonia slip. The reaction temperature for the reduction reaction ranges between 480-800 °F with optimum NO_X removal occurring at approximately 700 °F. Efficient SCR systems require stable flue gas streams in regard to temperature, flow rate, and NO_X concentrations. If designed and operated efficiently, SCR systems can reduce NO_X emissions by 70% - 90%.[2] SCR is potentially applicable to the affected sources; as such, this control measure is included for consideration in this study.

5.1.21 Selective Noncatalytic Reduction (SNCR)

Similar to SCR systems, SNCR is a type of post combustion, add-on NO_X emissions control technology whereby ammonia or urea is injected into the combustion source to reduce NO_X into elemental nitrogen and oxygen. The key difference between SCR and SNCR is that SCR uses a catalyst for the reduction reaction to take place. However, for SNCR systems to be effective, the ammonia or urea must be injected into a region with a narrow temperature range (usually 1600–2100 °F). Different factors such as temperature, residence time, type of reducing agent, reagent injection rate, uncontrolled NO_X level affect the reduction potential of this technology. The reaction temperature is critical since heat is needed to drive the reaction. At lower temperatures, reaction kinetics are slow, resulting in potential ammonia slip. At higher temperatures, ammonia oxidizes resulting in additional NO_X formation. If designed and operated efficiently, SNCR systems can reduce NO_X emissions by 70% - 90.[3] SNCR is potentially applicable to the remaining sources. As such, this control measure is included for consideration in this study.

5.1.22 Fuel Switching

The order of fuels based on highest NO_X emissions is coal, oil, NG, and BFG. BFG burns at a much lower temperature than NG resulting in the least amount of NO_X emissions. The use of maximum BFG is the primary objective at the Indiana Harbor Facilities since the gas is also generated on site. The remaining fuel fired at the facility is NG which is the next lowest NO_X fuel. Accordingly, fuel switching is not an option considered in this study.

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[2] U.S. EPA Cost Control Manual, 2002. https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual

[3] *Ibid*

5.2 Boilers

CCIH operates seven NG fired boilers at the CCIH, grouped into the units at CCIHW (i.e., Boilers #6-#8) and CCIHE (Boilers 501-504) below.

5.2.1 Boilers 6-8

Boilers 6 and 7 are wall-fired boilers manufactured by Babcock & Wilcox with 6 burners each. Pursuant to a study by AECOM in 2023 (see Appendix D), the units have been de-rated from 454 MMBtu/hr (as permitted) to 329 and 356 MMBtu/hr, respectively, due to tube failures and other issues affecting boiler capacity. Boiler 8 was manufactured by Combustion Engineering and is tangentially fired boiler with 2 burners in each of the 4 corners. This unit has been de-rated from 1,090 MMBtu/hr to 612 MMBtu/hr for similar reasons. All three units were originally designed to burn oil, BFG or NG. The oil burners have been removed and their original locations covered with steel plate.

Up until recently, these boilers have operated with BFG as the primary fuel, which is inherently low-NO_X due to the flame temperature. However, the blast furnaces at CCIHW (IH3 and IH4) have been idled since 2022. Thus, there is currently no source of BFG for Boilers 6-8 which requires the units to burn NG only. In 2023 when the units operated for an entire calendar year with no BFG, Boilers 6-8 operated at 30% of their total combined permitted capacity, primarily to produce steam for the #3 Steel Producing unit (3SP).

5.2.1.1 Step 1 – Identify All Control Options

The following technologies are available for reducing NO_X emissions from the boilers to the presumptive RACT emission rates:

- SNCR/SCR
- LNB (with FGR or OFA)

The technical feasibility of each of these options is discussed in Step 2 below.

5.2.1.2 Step 2 – Eliminate Technically Infeasible Options

5.2.1.2.1 <u>SNCR/SCR</u>

While industrial boilers utilize economizers making the exhaust temperatures too low to be conducive to SNCR operation without extensive re-heating, there are instances in which an SCR is used for NO_X control. It is important to note that these units have traditionally fired BFG as the primary fuel and there is no industrial knowledge to suggest that SNCR or SCR is a viable control option for BFG-fired boilers. As stated above, however, these units have operated as NG-fired boilers since the blast furnaces at CCIHW were idled in 2022. Therefore, this RACT analysis considers these units as NG-fired boilers for the purposes of this report as a worst-case analysis.

CCIH worked with AECOM in August 2023 to assess the technical and economic viability of SNCR and SCR add-on control. The result of the analysis is provided in Appendix D. Though each have limitations in the ability to be successfully applied to the CCIHW boilers, they are considered technically feasible for purposes of this RACT Study. The economic feasibility of retrofitting both SNCR and SCR on the boilers is evaluated in Steps 3-4 below.

5.2.1.2.2 LNBs (with FGR or OFA)

As stated above, CCIH worked with AECOM in August 2023 to provide a technically viable path for achieving compliance with the 0.09 lb NO_X/MMBtu presumptive RACT. The AECOM report included in Appendix D states that Boiler 6 and 7 would require LNB + FGR in order to meet the presumptive RACT limit, while Boiler 8 would require LNB + FGR or LNG + OFA.[4] These options are further explored in Steps 3-4 below.

5.2.1.3 Step 3 – Rank Remaining Control Options

The remaining technically feasible options for controlling NO_X emissions from Boilers 6-8 are as follows:

Table 5-1. Remaining Control Options

Emission Unit	NO_X Removal Technology	Expected Removal Efficiency
Boiler 6	LNBs (Zeeco or B&W) + FGR SNCR SCR	40-70% 25% 70-90%
Boiler 7	LNBs (Zeeco or B&W) + FGR SNCR SCR	40-70% 25% 70-90%
Boiler 8	LNBs (Zeeco or B&W) + OFA SNCR SCR	40-70% 25% 70-90%

5.2.1.4 Step 4 – Evaluation of Most Effective Control Option

5.2.1.4.1 LNBs

The detailed cost calculations of installing LNBs in the affected boilers are shown in Appendix A. Table 5-2 presents a summary of the cost-effectiveness calculations for LNBs on a PTE basis. The cost calculations in Appendix A use an emissions assessment from AECOM as the basis, as this is the only testing performed on the units during NG-only operation. The AECOM study is included as Appendix D.

Table 5-2. Cost-Effectiveness of Installing New LNBs in Boilers 6-8 (PTE Basis)

Emission Unit	Technology	Total Capital Investment	Total Annualized Costs	NO_X Removed (tpy)	Cost Effectiveness ($/ton)
Boiler 6	LNB + FGR	$ 13,700,000	$ 2,317,760	1,050	$ 2,207.08
Boiler 7	LNB + FGR				
Boiler 8	LNB + OFA				

As shown in the above table, LNB + FGR (for Boiler 6 and 7) and LNG + OFA (for Boiler 8) is economically reasonable based on the PTE analysis (i.e., when assuming the units operate at maximum MMBtu/hr capacity for 8,760 hr/yr).

[4] LNG + OFA was also presented for Boiler 6 and 7 but commentary within the report makes it clear that OFA is not a viable option unless substantial portions of the boilers tubes were relocated.

CCIH has provided a secondary analysis for Boilers 6-8 in Table 5-3 below. This analysis is based on actual operating conditions. The boilers operate only to meet steam demand for CCIHW. The MMBtu/hr capacity of the units is not fully realized even on an instantaneous basis, and sustained operation above approximately 60% utilization is infrequent due to lack of steam consumers, especially when limiting operation as needed to comply with the current NO_X limitations for ozone season. IDEM has readily acknowledged that a cost feasibility assessment based on actual operating conditions is appropriate, with the assumed contingency based on Ohio EPA's RACT program that actual operating conditions will correspond to a "RACT Trigger" that would require a subsequent RACT analysis. The RACT Trigger would effectively be a rolling 12-month NO_X emission threshold calculated as the average operating condition rate used in the cost calculations (MMBtu/hr) multiplied by the current NO_X emission rate (lb NO_X/MMBtu) used in the cost calculations and 8,760 hr/yr of operation.

Table 5-3. Cost-Effectiveness of Installing New LNBs in Boilers 6-8 (Actual Operations)

Emission Unit	Technology	Total Capital Investment	Total Annualized Costs	NO_X Removed (tpy)	Cost Effectiveness ($/ton)
Boiler 6	LNB + FGR				
Boiler 7	LNB + FGR	$ 13,700,000	$ 2,317,760	381.11	$ 6,081.53
Boiler 8	LNB + OFA				

As provided in the table above, when considering actual operations, it is not economically reasonable to retrofit the CCIHW boilers with the combustion modification necessary to meet the 0.08 lb NO_X/MMBtu presumptive limits.

5.2.1.4.2 <u>SNCR/SCR</u>

As part of the technical study performed by AECOM in 2023 (see Appendix D), AECOM evaluated the economic feasibility of retrofitting the affected boilers with SCRs. The study indicated that it is not economically reasonable to retrofit the CCIHW boilers with SCRs. The detailed cost calculations performed by AECOM are shown in Appendix D. CCIH did not recreate the cost calculations for SNCR and SCR as add-on control is not a realistic path forward considering technical challenges and cost-effectiveness.

5.2.1.5 Step 5 – Select RACT

For the CCIHW boilers, CCIH has demonstrated that retrofit installation of SCRs on the affected boilers is not cost effective. Further, CCIH has demonstrated that installing the necessary LNBs to meet the 0.08 lb NO_X/MMBtu presumptive limit is not cost-effective on an actual operations basis.

For this reason, CCIH is proposing a RACT Trigger equal to the actual emissions rate of 635.2 tpy NO_X for Boilers 6-8, which is derived in the cost calculations provided in Appendix A. The RACT Trigger would require that CCIH develop and submit a new RACT analysis within one year if exceeded. This represents an approximate 65% restriction on the PTE of the units.

In addition, the units will comply with the following good combustion practice requirements:

1. Conduct tune-ups on the burners as required by 40 CFR 63 Subpart DDDDD (i.e., the "Boiler MACT") when burning less than 90% BFG by volume.
2. Limit the fuel used in the units to NG or BFG.
3. Install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices for the control of the NO_X emissions from the unit.

5.2.2 Boilers 501-504

Boilers 501-504 are BFG-fired top gas boilers rated at 520 MMBtu/hr (Boilers 501-503) and 561.6 MMBtu/hr (Boiler 504). The units produce utility steam for operating turbo-blowers in the generation of cold blast (wind) to the blast furnace, high-pressure steam for power generation at the turbine, and low-pressure steam for use throughout CCIHE. Each boiler predominantly fires BFG and automatically supplements NG to maintain BFG header pressure.

5.2.2.1 Step 1 – Identify All Control Options

The following technologies are available for reducing NO_X emissions from the boilers:

- SCR
- LNB (with FGR or OFA)

The technical feasibility of each of these options is discussed in Step 2 below.

5.2.2.2 Step 2 – Eliminate Technically Infeasible Options

5.2.2.2.1 SNCR/SCR

There is no industrial knowledge to suggest that SCR is a viable control option for BFG-fired boilers. Therefore, SNCR/SCR has been deemed technically infeasible for these units.

5.2.2.2.2 LNBs

As quoted in the Briefing Sheet accompanying the 2010 Nucor Permit to Construct (PSD-LA-740), "The combustion of BFG in the top gas boilers requires the supplement of NG in order to maintain flame stability and prevent flame-outs of the burners. The use of low NO_X burners would attempt to stage fuel gas at the limits of combustibility and potentially prevent combustion of the fuel from occurring. Thus, LNBs are not a feasible control technology for the top gas boilers."

Furthermore, with regard to multi-fuel boilers such as Boilers 501-504, when firing a combination of BFG with NG, the excess air needed for BFG is high because BFG contains a high concentration of the inert gases carbon dioxide and nitrogen (CO_2, N_2) and a low higher heating value (HHV). This results in a higher combustion air volume burning with a low adiabatic flame temperature. Thus, the F-factor for BFG is approximately 16,500 scf/MMBtu compared to approximately 8740 scf/MMBtu for NG. When BFG is co-fired with NG, there is a significantly higher amount of excess air available to convert to NO_X from the NG. Therefore, the mitigation benefits from installing LNB would be substantially negated from the fact that there will be a considerable amount of excess air present as required for BFG.

5.2.2.3 Step 3 – Rank Remaining Control Options

There are no remaining technically feasible control options for the BFG-fired boilers.

5.2.2.4 Step 4 – Evaluation of the Most Effective Control Option

There are no remaining technically feasible control options for the BFG-fired boilers.

5.2.2.5 Step 5 – Select RACT

Since there are no control devices, including LNBs, that are both technically feasible and cost-effective, CCIH proposes the following operational restrictions as RACT:

1. Limit the fuel used to no less than 90% BFG by volume per year per boiler.
2. Continued compliance with existing ozone season requirements in place in the current Title V.
3. Install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices for the control of the NO_X emissions from the unit.

5.3 Blast Furnace IH3, IH4 and IH7

Blast furnaces are used to convert iron ore and iron-bearing raw materials to hot metal. The process is completed in a vertical shaft furnace in which raw materials (ore, coke, and flux) are introduced in batch additions via a skip car or a rotary feed at the top of the column. Once the molten iron is produced, the furnace is tapped and the molten iron flows through a series of troughs into refractory lined bottle cars for rail transfer to the steel shop(s). Combustion occurs within the shaft generating heat that melts the iron and reduces the oxides forming metallic iron.

Combustion occurs by introduction of pre-heated air (blast) through tuyeres. Carbon in the coke is first converted to CO_2 which passes upward through the burden heating the ore. In the burden part of the CO_2 produced by coke combustion is reduced to carbon monoxide (CO) by contact with iridescent coke which has been heated by the exhaust gases passing through the bed. This reaction is referred to as the Boudouard reaction. The top gases are passed through a scrubber to remove particulate matter (PM) and then used as fuel in the furnace stoves, or as fuel for other processes in the steel mill, or excess BFG is sent to a flare. Under normal operating conditions, the HHV of the BFG is approximately 120-125 Btu/scf which results in lower flame temperature and low thermal NO_X emissions.

The furnaces are equipped with regenerative heat exchangers, which are commonly referred to as stoves, in which the blast air is heated. BFG and supplemental NG are fired in the stoves to heat the stove refractory, called checkers. When the required checker temperature is achieved the gas flow is reversed and stored sensible heat is recovered into the blast air. There are 3 (IH3/4) or 4 (IH7) stoves on each furnace which are cycled through to provide hot blast to the blast furnace. The combustion gases are vented through a common stack from the stoves, and IH7 sends a portion of the exhaust to its pulverized coal facility for waste heat recovery.

CCIH operates Blast Furnaces IH3, IH4, and IH7 stoves at CCIH as discussed in Section 2. The blast furnace stoves predominantly burn BFG, which has a low heating value and contains inert, critical factors for reducing combustion temperature. As such, NO_X emissions from burning BFG are inherently low thermal NO_x and the potential for further NO_X reduction is considerably low. NO_X emissions are generated at the stoves, casthouses, and flares of the blast furnaces predominately due to variable trace quantities of nitrogen bearing compounds like ammonia NH_3.

5.3.1 Step 1 – Identify All Control Options

The following technologies are available for reducing NO_X emissions from Blast Furnace IH3, IH4 and IH7.

- SCR
- SNCR
- LNB

The technical feasibility of each of these options is discussed in Step 2 below.

5.3.2 Step 2 – Eliminate Technically Infeasible Options

5.3.2.1 SCR

5.3.2.1.1 Stoves

There are several significant challenges with respect to design and installation of SCR on the blast furnace stoves that render it technically infeasible:

- The exhaust temperature from the blast furnace stoves (500 °F) is too low for the application of SCR (NO_X removal with SCR units is at the highest for temperature range between 600-700 °F) and the extreme volumes of exhaust gases would need to be re-heated with NG to achieve the needed SCR activation temperature. Reheating the large volume of gas would require firing wasteful NG which would result in additional NO_X emissions and significant greenhouse gas (GHG) emissions.
- There has been no application of SCR to any blast furnace stove in the Iron and Steel sector. Accordingly, SCR vendors have no experience in specification of SCR design or catalyst formulation as they do with the power industry.
- The flue gas volume from stove combustion is significant and the surface area for SCR design would be extremely large. Therefore, the physical dimensions of any proposed SCR would also be large. The retrofit cost for installation of the SCR would have to include structural support and an induced draft fan to overcome the additional static pressure loss, both of which would be very costly.
- The achievable removal efficiency of SCR is highly dependent on the inlet NO_X loading. Blast furnaces operate with remarkably high exhaust volumes and relatively low inlet NO_X concentrations, particularly when firing BFG. The low inlet NO_X concentrations would result in low removal efficiency. The reduced efficiency would also require a higher ammonia molar ratio likely to result in significant ammonia slip.

The effect of particulate in the combustion gases from BFG fuel firing is expected to foul or poison the catalyst, reducing effectiveness even further. SCR vendors have no data on these gas streams and would require significant testing to assess if this issue could be mitigated.

5.3.2.1.2 Casthouses (Baghouse Stack)

As discussed in previous sections, SCR is most efficient at removing NO_X between 700 ºF and 750 ºF. The temperatures entering these baghouses are low (less than 200 ºF) so there would have to be significant reheat for add-on control, which is especially difficult considering the large airflow (approx. 650,000 acfm total across two separate baghouses for IH7 and 300,000 for IH4). Thus, SCR is not technically viable for the blast furnace casthouse baghouse stacks emissions at CCIH.

5.3.2.1.3 Casthouses (Fugitive)

There are fugitive NO_X emissions that are uncaptured from the baghouses or coming from exposure of the trough and runners between the tapholes, tilters, and the slag pits. These emissions vent from draft vents at the top of the building or are routed to a roof/canopy collection system in the case of IH7. If emissions were able to be directed to an add-on control device for IH3/4 by building a dedicated stack, there would be similar issues regarding high flow, low temperature and low NO_X concentrations as described above, and as already seen at IH7's Canopy Baghouse. Thus, SCR is not technically viable for the blast furnace casthouse fugitive emissions at CCIH.

5.3.2.1.4 Flare

The blast furnace flares combust excess BFG from the blast furnaces at CCIH. Use of SCR/SNCR to control NO_X emissions from the open flare is technically infeasible given the absence of a physical stack.

5.3.2.2 SNCR

SNCR is not technically feasible for the same reasons as stated above for SCR.

5.3.2.3 LNB

5.3.2.3.1 Stoves

As discussed in the prior section, the blast furnace stoves operating at CCIH predominantly burn BFG (greater than 90% BFG on average) which has inherently low NO_X emissions. NG enrichment is used only when the heat content is below a certain necessary threshold (approximately 110 Btu/scf) and following refractory repair work for slow controlled warmup and dry-out. Accordingly, CCIH considers RACT to have already been satisfied for the stoves with the use of BFG as the primary fuel.

5.3.2.3.2 Casthouses (Baghouse Stack)

Not applicable – there are no engineered burners used in the casthouse beyond the system used for rebuild/maintenance.

5.3.2.3.3 Casthouses (Fugitive)

Not applicable – there are no engineered burners used in the casthouse beyond the system used for rebuild/maintenance.

5.3.2.3.4 Flare

Flares typically operate with pilot flames to provide heat (or ignition source). Accordingly, LNBs are technologically infeasible for the blast furnace flares at CCIH.

5.3.3 Step 3 – Rank Remaining Control Options

There are no remaining control options that are deemed technically feasible for the Blast Furnaces IH3, IH4 and IH7 Stoves.

5.3.4 Step 4 – Evaluation of the Most Effective Control Option

There are no remaining control options that are deemed technically feasible for the Blast Furnaces IH3, IH4 and IH7 Stoves.

5.3.5 Step 5 – Select RACT

5.3.5.1.1 Stoves

CCIH is unable to propose a numerical restriction for the blast furnace stoves as RACT because stack tests cannot occur at worst-case conditions. The amount of supplemental NG fuel needed at any time is dependent on the heat content of the BFG and NG. NG cannot be unnecessarily introduced to the blast furnace at high levels to create worst-case emissions for stack testing due to inherent safety limitations.

Alternatively, CCIH proposes an operational restriction of no less than 90% BFG by volume on a rolling 30-operating day basis. An operating day is defined as any calendar day with 12 hours or more during which wind is being added to the furnace and the top pressure of the furnace is greater than 5 pounds per square inch (psi). This operational restriction ensures that CCIH has the operational flexibility needed to supply the necessary heat content to the blast furnace while also ensuring that NO_X emissions are not significantly higher than what is expected from combusting solely BFG.

5.3.5.1.2 Casthouses

Based on the above analysis, there are no technically feasible NO_X control options for blast furnace casthouses.

5.3.5.1.3 Flare

For the flare, RACT is proposed as a requirement to install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices for the control of the NO_X emissions from the unit.

5.4 Basic Oxygen Furnaces #1, #2, #50 and #60

Basic Oxygen Furnaces (BOFs) are batch processes used in integrated iron and steel facilities to convert hot metal produced in the blast furnace and scrap into steel. Hot metal contains between 3.5 and 4.5% carbon. When converting the hot metal to steel, the carbon is removed by oxidation in the BOF vessel. This process is completed by blowing oxygen into the liquid metal bath which oxidizes the carbon, forming CO and CO_2. Impurities are removed by forming slag from the addition of flux (quick lime, dolomitic lime, and limestone). The oxidation of carbon and silicon generates heat which melts the scrap and raises the liquid temperature to about 2,800°F. The CO and CO_2 produced are emitted from the vessel along with a high concentration of particulate matter which is removed using a particulate control device. The blowing process does not generate significant amounts of NO_X inside the BOF vessel due to the consumption of oxygen (O_2) in the heat and the exclusion of air containing nitrogen.

The BOF blowing process occurs in batch cycles with charging, blowing, and tapping events. Each batch cycle is referred to as a heat. The total cycle can be around one hour with the blowing period between approximately 18 and 24 minutes. Off-gas temperatures entering the fume capture hood can be between 350°F during charging and 3,200°F during the peak blow period of the heat cycle. There are two (2) types of BOF furnaces based on how the off gases are processed after leaving the vessel: full combustion/open hood and suppressed combustion/closed hood. Both No. 3 and No. 4 Steel Producing facilities operate open hood vessels.

The full combustion operations at CCIH (as opposed to suppressed combustion BOFs) capture the vessel off gases in an open hood. Ambient air is introduced between the vessel mouth and hood. The amount of air introduced is controlled by the system draft to prevent fugitive emissions and to assure combustion of CO and hydrogen (H_2) emitted from the vessel. As a result of the combustion, the gas temperature increases to about 3,800°F and NO_X can be formed as thermal NO_X. At No. 3 Steel Producing the gases are cooled by water sprays located in the evaporation chamber just above the water-cooled hood to about 150-620°F before being introduced to an electrostatic precipitator (ESP) for particulate removal for #1 & #2 BOFs. At No. 4 Steel Producing off-gas is quenched by water sprays before passing through a wet venturi scrubber for #50 & #60 BOFs.

Ladle preheaters are included with the BOFs, as they are employed in steel shops to dry the ladle refractory to cure refractory after ladle repairs and to maintain temperature and reduce thermal cycling that damages refractory during operational pauses. In both applications an open gas flame is introduced into the ladle to increase the refractory temperature. The equipment typically includes either a cold air/fuel burner in a vertical (down-fire) position or horizontal position depending on the manufacturer. Combustion gases are vented through the gap between the cover and the ladle rim, exhausting emissions directly into the building without any dedicated stacks.

5.4.1 Step 1 – Identify All Control Options

The following technologies are available for reducing NO_X emissions from the BOFs:

- SCR
- SNCR
- LNBs

The technical feasibility of each of these options is discussed in Step 2 below.

5.4.2 Step 2 – Eliminate Technically Infeasible Options

The technical feasibility of each of these options is discussed in Step 2 below.

5.4.2.1 SCR

5.4.2.1.1 BOF Vessels

The mouth of the furnace exhausts to a hood and combusts CO in the hood, and the resulting off-gas goes to either an electrostatic precipitator or a scrubber. If SCR were placed after the ESP or scrubber, the cooled (approx. 140 °F) and moisture-laden gases would require significant reheating with NG to achieve the required reaction temperature. If there was a unit redesign to allow for residence time between the BOF and the particulate controls, the high concentration of metal oxide particulates would deteriorate the catalyst and poison the noble metals if SCR were installed prior to the particulate control train.

Furthermore, the temperature in the primary hood is variable over the batch process blow period and the required gas temperature and residence time for proper SCR functionality cannot be achieved between the combustion in the hood and the particulate controls. To prevent degradation of the SCR catalyst, the catalyst bed would be required to be held at the operating temperature between the batch processing of heats. This would result in combustion of a significant amount of wasteful NG which would generate more NO_X than that which is potentially formed in the combustion hood.

For the reasons stated above, CCIH has determined that SCR is technically infeasible for retrofit to the BOFs at CCIH.

5.4.2.1.2 Ladle Preheaters

Emissions from the ladle preheaters are fugitive in nature and exhaust into the melt shop. Given the absence of a stack, post-combustion controls such as SCR are technically infeasible.

5.4.2.1.3 Secondary Vents

The secondary emission point may include a portion of the calculated NO_X emissions for the BOFs. Charging, tapping, and miscellaneous furnace emissions are controlled by a secondary ventilation baghouse at No. 4 BOF, having a flow rate of upwards of 600,000 acfm with a relatively low (<120 °F) outlet temperature, rendering add-on control technically infeasible due to the need to reheat an extremely large flow with relatively low NO_X concentration. Charging and tapping at No. 3 BOF are controlled by the ESP where there are similar issues regarding flow and NO_X concentration. Thus, SCR has been deemed technically infeasible.

5.4.2.2 SNCR

SNCR has been deemed technically infeasible for the same reasons as described for SCR above.

5.4.2.3 LNBs

5.4.2.3.1 BOF Vessels

Not applicable – there are no burners in the BOF vessels.

5.4.2.3.2 Ladle Preheaters

Ladle preheaters at the BOFs burn NG exclusively and utilize inherently low NO_X burners (cold air-fired burners). While these units cannot be stack tested, Bloom has indicated that the cold air-fired burners may achieve NO_X emissions as low as 0.056 lb NO_X/MMBtu. To install burners designed as LNBs/ULNBs, a tight seal would be necessary to stage air/fuel as described elsewhere in this report. Ladle preheaters cannot have a tight seal as an air leak is incorporated by design to avoid suffocating the furnaces. Therefore, installation of ULNBs for the ladle preheaters is not technically feasible.

5.4.2.3.3 Secondary Vents

Not applicable – there are no burners in the secondary vent at No 4 BOF.

5.4.3 Step 3 – Rank Remaining Control Options

There are no remaining viable control options for the BOFs.

5.4.4 Step 4 – Evaluation of the Most Effective Control Option

There are no remaining viable control options for the BOFs.

5.4.5 Step 5 – Select RACT

Based on the above analysis, there are no technically feasible NO_X control options for the BOF vessels and secondary vents. CCIH will continue to operate the existing burners which have inherently low NO_X emissions at the ladle preheaters.

5.5 2SM No. 2 Galvanizing Line

The 2SM No. 2 Galvanizing Line at CCIHW consists of processes in which steel is hot dipped to add coating. The line consists of a NG fired galvanizing furnace (49.65 MMBtu/hr) and a galvanizing line flame furnace (150 MMBtu/hr) in which NO_X emissions are generated.

The furnace consists of three zones: an unfired preheat tunnel, a direct-fired section, and indirect-fired section(s).

- In the preheat tunnel, excess combustibles introduced in the direct-fired section are ignited, generating NO_X emissions. According to vendor data, the preheat tunnel accounts for approximately 30-40% of all NO_X emissions for the coating line.
  - The exhaust from this area vents along with the direct fired section through a natural draft chimney that is routed just west of the furnace and out of the roof. Because the chimney lacks a draft fan, flow is directly proportional to the firing rate/line speed.
- The burners in the direct-fired section operate without excess O_2 to limit the presence of oxygen in the furnace. The NO_X generated from the burners and other combustion byproducts exit the natural draft chimney along with the preheat section. The forced blanketing gas introduced into the exit of the furnace that flows countercurrent to the direction of steel pushes the combustion gases from the direct-fired burners back to the preheat tunnel where it is emitted as described above.
- Finally, the indirect-fired section of the furnaces allows hot exhaust from the NG burners to vent through single pass pipes that radiate heat into the furnace.
  - Each individual burner has a dedicated vent for exhaust. Thus, there are approximately 180 single pass pipes and corresponding exhaust vents that all individually emit fugitive combustion products directly to the inside of the building.

As stated in the current Title V permit, nearly half of the galvanizing furnace (on a MMBtu/hr basis) is equipped with ULNBs. The unit also involves inherently lower-NO_X cold air burners.

5.5.1 Step 1 – Identify All Control Options

The following technologies to be generally available for controlling NO_X emissions from the continuous annealing furnace

- SCR
- SNCR
- LNB

The technical feasibility of each of these options is discussed in Step 2 below.

5.5.2 Step 2 – Eliminate Technically Infeasible Options

5.5.2.1 SCR/SNCR

It is technically infeasible to capture emissions from the indirect-fired section of the furnace as each burner has its own stub exhaust pipe that vents to the interior of the building.

5.5.2.2 LNB

The burner manufacturer, Bloom Engineering (Bloom), has provided information stating narratively that the 2SM No. 2 Galvanizing Line could achieve 0.09 lb NO_X/MMBtu by replacing approximately 110 burners at a cost of $8,500/burner (71 burners have already been replaced with LNBs in recent years). This information is provided in Appendix B and used for the cost calculation in Appendix A and in Table 5-5 below.

5.5.3 Step 3 – Rank Remaining Control Options

The remaining technically feasible options for controlling NO_X emissions are provided in Table 5-4.

Table 5-4. Remaining Control Options

NO_X Removal Technology	Expected Removal Efficiency
Bloom LNBs/ULNBs	Est. 33%

5.5.4 Step 4 – Evaluation of the Most Effective Control Option

Based on the cost information provided above, the economic feasibility of replacing the current burners in the indirect-fired and direct-fired sections with newer model burners was estimated. The detailed cost calculations are shown in Appendix A. Table 5-5 presents a summary of the cost-effectiveness calculations on a PTE basis.

Table 5-5. Cost-Effectiveness for Technically Feasible Control Devices (PTE Basis)

Emission Unit	Technology	Total Capital Investment	Total Annualized Costs	NOX Removed (tpy)	Cost Effectiveness ($/ton)
2SM No. 2 Galvanizing Line	Bloom LNB/ULNB	$ 1,559,113	$ 250,114	19.06	$ 13,123.54

As shown in the above table, it is economically unreasonable to replace the existing burners with new LNBs/ULNBs.

5.5.5 Step 5 – Select RACT

Since there are no control devices, including LNBs, that are both technically feasible and cost-effective, CCIH proposes the following operational restrictions as RACT:

1. Conduct tune-ups on the burners as required by the Boiler MACT.
2. Limit the fuel used at the burners to NG only.
3. Install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices for the control of the NO_X emissions from the unit.

Note that CCIH has not proposed a numerical limit for NO_X RACT. As is evident by the process description, it is not feasible to perform a traditional Method 1-4,6 stack test on the 180 individual exhaust vents of the indirect fired section of the furnace. Thus, there is no baseline emissions test from which a numerical lb NO_X/MMBtu emission limit may be derived. However, CCIH is confident that the combustion practices described above are sufficient to ensure NO_X emissions from the continuous annealing furnace will be mitigated to the fullest extent practical.

5.6 Recycle Plant

CCIH operates a Recycle Plant at CCIHE. At the Recycle Plant, iron bearing reverts from the various processes at CCIH are mixed with coke/coal, flux, blended iron ores, and other materials. A NG burner(s) ignites the blended materials at the introduction to a strand bed and wind boxes below the strand pull gases through the strand bed to multiclones and a baghouse prior to exhaust. The agglomerated iron from the Recycle Plant process is then used in the Blast Furnaces. A vast majority of NO_X generated from the Recycle Plant is generated from the exposure of ignited material to atmospheric nitrogen on the strand bed. The contribution of NO_X from the ignition burner(s) is inconsequential.

5.6.1 Step 1 – Identify All Control Options

The following technologies are available for controlling NO_X emissions from the Recycle Plant:

- SCR
- SNCR

The technical feasibility of each of these options is discussed in Step 2 below.

5.6.2 Step 2 – Eliminate Technically Infeasible Control Options

5.6.2.1 SNCR

As described above, the Recycle Plant exhaust gases are pulled down through the furnace bed and exhausted to cyclones and a baghouse. The exhaust gases are typically less than 250 °F due to large amounts of ambient/tramp air that is pulled through the end of the strand to cool the bed before it goes through the breaker. Therefore, as discussed elsewhere, there would need to be significant reheating of the exhaust with duct burners to utilize SNCR. Reheating is not feasible due to the large variable air flow and limitations of the baghouse capacity to maintain draft in addition to large volumes of burner combustion gases. Therefore, CCIH has determined that SNCR is technically infeasible.

5.6.2.2 SCR

The temperature profile of the exhaust, as described above, is more conducive to SCR operation. However, the exhaust gases contain fine metal particles from the raw material fines. The windbox duct in the exhaust gas train is lined with refractory all the way up to the multiclones and draft fan, and degrade due to the abrasive exhaust, which would likely plug, erode, and/or poison the SCR catalyst bed, and would not achieve desired control. To consider SCR, the existing baghouse would need to be replaced with a high-temperature baghouse of the proper size that would need a long duct to a location with the necessary footprint, and then additional duct burners would have to be installed to reheat the exhaust post-baghouse. Therefore, CCIH has determined that SCR is technically infeasible.

5.6.3 Step 3 – Rank Remaining Control Options

There are no remaining technically feasible control options for the Recycle Plant.

5.6.4 Step 4 – Evaluation of the Most Effective Control Option

There are no remaining technically feasible control options for the Recycle Plant.

5.6.5 Step 5 – Select RACT

Based on the above analysis, there are no technically feasible NO_X control options for the Recycle Plant.

5.7 Lime Plant Kilns

The No. 1 Lime Plant operates two kilns, #1 and #2 Kiln, (284 MMBtu/hr each) and produces lime for use throughout the facility. Lime is produced through thermal decomposition of limestone in rotary kilns, where calcium carbonate decomposes into calcium oxide and waste carbon dioxide at temperatures in excess of 1,800 °F. The kilns are fired with at least 70% NG and up to 30% Btu input from residual fuel oil.

Particulate emissions from these sources are controlled with a set of cyclone separators and two baghouses. The Lime Plant No. 1 and No. 2 Preheater and Rotary Kilns generate NO_X emissions from NG and fuel oil combustion. The preheater utilizes residual heat from the rotary kiln combustion gases to preheat limestone feed. This increased energy efficiency results in less fuel usage, and less NO_X emissions as a result. The use of a preheater is a NO_X emission control measure for Lime Plant No. 1 and No. 2.

5.7.1 Step 1 – Identify All Control Options

The following technologies are available for controlling NO_X emissions from the Recycle Plant:

- SCR
- SNCR
- LNBs

The technical feasibility of each of these options is discussed in Step 2 below.

5.7.2 Step 2 – Eliminate Technically Infeasible Control Options

5.7.2.1 SCR/SNCR

The RACT/BACT/LAER Clearinghouse (RBLC) and industrial permits for similar sources do not include any NO_X mitigation techniques for lime kilns other than methods of "good combustion practices" for gaseous/liquid fuel fired units. With no industry precedent for add-on control, CCIH considers SCR/SNCR technically infeasible.

5.7.2.2 LNBs

As stated above, the RBLC does not suggest there is industry precedent for LNBs. Furthermore, in a similar manner to the explanation provided in Section 5.2, mixed fuel burners generally do not have low-NO_X capabilities due to differences in F-factors of fuel, resulting in excess air that counteracts the NO_X reducing techniques of LNBs. The lime kilns operate with mixed fuel burners; therefore, LNBs are not feasible for the lime plant kilns.

5.7.3 Step 3 – Rank Remaining Control Options

There are no remaining technically feasible control options for the Lime Plants.

5.7.4 Step 4 – Evaluation of the Most Effective Control Option

There are no remaining technically feasible control options for the Lime Plants.

5.7.5 Step 5 – Select RACT

CCIH has demonstrated that there are no feasible control options for NO_X at the No. 1 and No. 2 Lime Kilns. Thus, CCIH recommends that RACT for these units is the continued implementation of good combustion practices.

5.8 Hot Strip Mill Reheat Furnaces

CCIH operates the following Hot Strip Mill walking beam reheat furnaces (WBFs) at CCIHE:

- 80" Hot Strip Mill #4 WBF
- 80" Hot Strip Mill #5 WBF
- 80" Hot Strip Mill #6 WBF

The #4 WBF has an estimated maximum heat input capacity of 720 MMBtu/hr and is equipped with first generation LNBs. The #5 WBF and #6 WBF each have an estimated maximum heat input capacity of 685.6 MMBtu/hr. The #5 WBF and #6 WBF have 12 zones of burners, 10 of the zones have wall burners and 2 zones in the soak section have only roof burners. The roof burners are flat flame cold air-fired burners and are inherently low-NO_X due to the operating temperature.

5.8.1 Step 1 – Identify All Control Options

- SCR
- SNCR
- LNB

The technical feasibility of each of these options is discussed in Step 2 below.

5.8.2 Step 2 – Eliminate Technically Infeasible Control Options

5.8.2.1 SCR

CCIH is aware of one SCR installation on a new reheat furnace in the steel industry. Beta Steel (now NLMK) in Indiana was issued a PSD permit on May 30, 2003, requiring operation of SCR on a steel slab reheat furnace and compliance with an emission limit of 0.014 lb/MMBtu.[5] However, as noted in a response to comment document provided with Permit No. T127-9691-00036, Beta Steel submitted an application to increase the NO_X emission limit for the reheat furnace from 0.014 to 0.077 lb/MMBtu because "the non-steady state nature of the reheat furnace made it impossible to achieve a consistent level of SCR performance". Importantly, as a new construction project, the Beta Steel slab reheat furnace and corresponding exhaust system were designed specifically to accommodate SCR NO_X control. Conversely, installing SCR at CCIHE Facility would require retrofitting an existing system, which would only compound the issues with applying SCR technology to a slab reheat furnace.

The reheat furnaces at the CCIH have door(s) that continually open and close to allow cold slabs to be charged to the furnace and to remove reheated slabs of steel on the exit end of the furnace. The batch reheat furnace process of opening and closing the door(s) results in swings of the furnace exhaust temperatures that is detrimental to a successful SCR application.

While some SCR systems can accommodate temperature swings in the range of 200 ºF,[6] SCR does rely on vent gas temperatures being within a specific range to be effective and to avoid damage to the catalyst bed. Vent gas temperature must be relatively known and constant to be considered in the initial design of catalyst, from chamber size to type and amount of catalyst. This is a unique challenge to reheat furnaces, which operate at different temperatures depending on the type of steel being heated, the stage of the process, upstream/downstream bottlenecks for the slabs, and door openings and closing. U.S. EPA considered these difficulties in applying an SCR to slab reheat furnaces in their decision to remove the requirement initially proposed for slab reheat furnaces to install and operate an SCR within the released Good Neighbor Plan for 2015 Ozone NAAQS (GNP) and replace it with a requirement to reduce NO_X emissions by 40%. The Technical Support Document (TSD) and NO_X Emission Control Technology Installation Timing for Non-EGU Sources document for the GNP include no presumption that employing SCR on slab reheat furnaces is a viable control option.[7,8]

For all the reasons stated herein, SCR is deemed technically infeasible for the reheat furnaces at CCIH.

5.8.2.2 SNCR

As discussed in prior sections, temperature is a critical factor for optimum NO_X removal in SNCR units. The flue gas temperatures from the furnaces are too low for SNCR to be effective (desired temperature range for efficient SNCR systems is 1600–2100 °F). The flue gases would have to be reheated by using NG to raise the gas temperatures in the range of 1600 to 2100 °F for effective reaction of NO_X with ammonia. This would require significant fuel cost and generate additional NO_X from the combustion of the NG. Further, low NO_X concentrations would result in low NO_X removal efficiencies. Accordingly, SNCR is deemed technically infeasible for the reheat furnaces.

5.8.2.3 LNBs

Bloom provided a proposal in 2020 that included an option for installing 61 Bloom 1600 series burners on each furnace achieving compliance with the 0.09 lb NO_X/MMBtu presumptive RACT limit. This proposal is included in Appendix B and used in the cost calculations below and in Appendix A.

5.8.3 Step 3 – Rank Remaining Control Options

The remaining technically feasible options for controlling NO_X emissions from the 80 Inch HSM SRFs are as follows:

Table 5-6. Remaining Control Options

NO_X Removal Technology	Expected Removal Efficiency
ULNB	45.5%

5.8.4 Step 4 – Evaluation of the Most Effective Control Option

The economic feasibility of replacing the current burners in the 80 Inch HSM SRFs was estimated. The detailed cost calculations are shown in Appendix A. Table 5-7 presents a summary of the cost-effectiveness calculations. Note that stack tests performed at near-maximum operating rates were used to establish the

"PTE Basis" emission factors used in the assessment summarized in Table 5-7. These stack test reports are provided in abridged form in Appendix C.

Table 5-7. Cost-Effectiveness for Technically Feasible Control Devices (PTE Basis)

Emission Unit	Technology	Total Capital Investment	Total Annualized Costs	NO_X Removed (tpy)	Cost Effectiveness ($/ton)
#4 WBF	ULNB	$ 4,044,214	$ 1,188,052	157.7	$ 7,534.57
#5 WBF	ULNB	$ 4,382,213	$ 1,287,344	543.5	$ 2,368.49
#6 WBF	ULNB	$ 4,382,213	$ 1,287,344	549.5	$ 2,342.60

As shown in the above table, ULNB installation is economically reasonable for #5 WBF and #6 WBF based on the PTE analysis (i.e., when assuming the units operate at maximum MMBtu/hr capacity 8,760 hr/yr).

CCIH has provided additional analysis for the #5 and #6 WBF in Table 5-8 below. Over any extended period of time (i.e., days or weeks) SRFs operate only to the extent needed based on upstream and downstream steel operations. The MMBtu/hr capacity of the unit is not fully realized and operation over approximately 50% capacity only occurs over short periods when high steel demand corresponds with "worst-case" heating needs for certain grades, sizes, and thicknesses of steel. IDEM has readily acknowledged that a cost feasibility assessment based on actual operating conditions is appropriate, with the assumed contingency based on Ohio EPA's RACT program that actual operating conditions will correspond to a "RACT Trigger" that would require a subsequent RACT analysis. The RACT Trigger would effectively be a rolling 12-month NO_X emission threshold calculated as the average operating condition rate used in the cost calculations (MMBtu/hr) multiplied by the current NO_X emission rate (lb NO_X/MMBtu) used in the cost calculations and 8,760 hr/yr of operation. Note that stack tests performed at typical operating rates were used to establish the "Actual Operations" emission factors used in the assessment summarized in Table 5-8. These stack test reports are provided in abridged form in Appendix C.

CCIH has calculated the cost effectiveness of the ULNB installations based on actual operating conditions for #5 and #6 WBF and summarized the analysis in Table 5-8 below.

Table 5-8. Cost-Effectiveness for Technically Feasible Control Devices (Actual Operations)

Emission Unit	Technology	Total Capital Investment	Total Annualized Costs	NO_X Removed (tpy)	Cost Effectiveness ($/ton)
#5 WBF	ULNB	$ 4,382,213	$ 1,287,344	156.64	$ 8,218.70
#6 WBF	ULNB	$ 4,382,213	$ 1,287,344	155.84	$ 8,260.60

As provided in the table above, when considering actual operations, it not economically reasonable to retrofit the #5 and #6 WBF with ULNBs that are capable of meeting the 0.09 lb NO_X/MMBtu presumptive limit.

5.8.5 Step 5 – Select RACT

#4 WBF

For the #4 WBF, CCIH has demonstrated that installing the necessary ULNBs to meet the 0.09 lb NO_X/MMBtu presumptive limit is not economically reasonable (refer to Table 5-7). As an alternative, CCIH is proposing the following good combustion practices as RACT:

1. Limit the fuel used in the SRF to NG only.
2. Install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices for the control of the NO_X emissions from the unit.

#5 WBF and #6 WBF

CCIH has demonstrated that it is not economically reasonable to install ULNBs on the #5 WBF and #6 WBF when considering actual operations. For this reason, CCBH is proposing a RACT Trigger equal to the actual emissions rate of 569.9 tpy NO_X for #5 WBF and #6 WBF, combined, which is equal to the sum of the RACT Triggers for each individual unit based on actual operations as provided in Appendix A (i.e., 286.0 tpy NO_X for #5 WBF and 283.9 tpy NO_X for #6 WBF).[5] The RACT Trigger would require that CCIH develop and submit a new RACT analysis within one year if exceeded. This represents an approximate 66% restriction on the PTE of the units.

In addition, the units will comply with the following good combustion practice requirements:

1. Limit the fuel used in the SRFs to NG only.
2. Install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices for the control of the NO_X emissions from the unit.

5.9 No. 3 Continuous Annealing Line

CCIH operates the No. 3 Continuous Annealing Line (3CAL) at the CCIHE, with an estimated maximum total heat input capacity of 108 MMBtu/hr.
The 3CAL consists of two furnaces, the annealing furnace and aging furnace. The annealing furnace includes a heat, soak, and gas jet cool (GJC) sections while the aging furnace includes the reheat and overage sections.

- All sections of the furnaces operate with indirect-fired radiant tube burners. Hot exhaust from the NG burners vent into exhaust mains that collect and discharge through one of three stacks, while the tubes of various sizes and configuration radiate heat on the steel strip inside the furnace.
- The exhaust gas ducts are combined from the individual burner tubes and collected by ID fans into the following groupings:
  - Heat Section Stack, (148 Burners)
  - Soak and GJC Sections Stack (72 Burners)

5.9.1 Step 1 – Identify All Control Options

The following technologies to be generally available for controlling NO_X emissions from the 3CAL:

[5] The NO_X RACT Trigger for #5 and #6 WBF are calculated separately and summed for a combined NO_X threshold because the units have different emission factors. The Boilers 6-8 NO_X RACT was calculated as a single cost analysis because the units use the same baseline emission factor.

- SCR
- SNCR
- LNB

The technical feasibility of each of these options is discussed in Step 2 below.

5.9.2 Step 2 – Eliminate Technically Infeasible Control Options

5.9.2.1 SNCR/SCR

As stated above, there are currently three stacks from this unit that share an unknown distribution of NO_X emissions to each. Thus, CCIH would have to redesign and construct a new exhaust system to reasonably employ add-on control. Furthermore, the exhaust temperatures will require significant reheating for SCR and an infeasible amount of reheating/duct burning for SNCR as discussed for other units. Considering the cost information presented below for LNBs (which generally require significantly less initial and ongoing costs than SCR) and the fact that the 3CAL is a relatively low NO_X-emitter, it can reasonably be stated that SCR and SNCR are not viable options for the 3CAL.

5.9.2.2 LNBs

The 3CAL has 220 burners in the unit, 71 of which have been replaced with LNBs by Bloom (80 burners have been supplied, 71 currently in place). This includes all 14 GJC section burners, 43 burners in the soak section, and 14 burners in the heat section. Bloom provided a quote to replace the remaining 149 burners as needed to comply with the 0.09 lb NO_X/MMBtu presumptive RACT limit. This quote is used in the assessment summarized below and provided in detail in Appendix B.

5.9.3 Step 3 – Rank Remaining Control Options

The remaining technically feasible options for further controlling NO_X emissions from the 3CAL is as follows:

Table 5-9. Remaining Control Options

Emission Unit	NO_X Removal Technology	Expected Removal Efficiency
No. 3 CAL	Bloom 2370 Ultra Low NOx burner	~55%

5.9.4 Step 4 – Evaluation of the Most Effective Control Option

Based on a vendor quote provided by Bloom Engineering to CCIH, the economic feasibility of replacing the remaining original burners in the 3CAL with newer model burners was estimated. Table 5-10 presents a summary of the cost-effectiveness calculations.

Table 5-10. Cost-Effectiveness of Installing New ULNBs in the No. 3 Continuous Anneal Line (PTE Basis)

Emission Unit	ULNB Model	Total Capital Investment	Total Annualized Costs	NO_X removed (tpy)	Cost Effectiveness ($/ton)
No. 3 CAL	Bloom 2370 Ultra Low NOx burner	$2,057,862	$ 330,123	44.6	$ 7,409.18

The current emission factor used in the cost calculation provided in Appendix A and summarized above is calculated based on burner-specific information from Bloom, because the Title V Permit basis does not consider that the unit has had LNBs installed in various zones. The calculation methodology is provided in Table 5-11 below:

Table 2. 3 CAL Emission Factor Calculation Methodology

Zone	Burner Type	#	MMBtu/hr	EF (#/MMBtu)
Gas Jet Cooling	Original	-	-	0.22
	LNBs	14	7.00	0.072
Heating Section	Original	134	54.50	0.28
	LNBs	14	8.40	0.085
Soaking Section	Original	15	3.60	0.178
	LNBs	43	9.20	0.054
		220	82.7	**0.213**

5.9.5 Step 5 – Select RACT

Since there are no control devices, including LNBs, that are both technically feasible and cost-effective, CCIH proposes the following operational restrictions as RACT:

1. Conduct tune-ups on the burners as required by the Boiler MACT.
2. Limit the fuel used in the 3CAL to NG only.
3. Install, maintain and operate the source in accordance with the manufacturer’s specifications and with good operating practices for the control of the NO_X emissions from the unit.

Note that CCIH has not proposed a numerical limit for NO_X RACT. While it may be feasible to test the furnaces’ three stacks in the future, the timing of the request from IDEM did not allow for baseline emissions testing. However, CCIH is confident that the combustion practices described above are sufficient to ensure NO_X emissions from the continuous annealing furnace will be mitigated to the fullest extent practical.

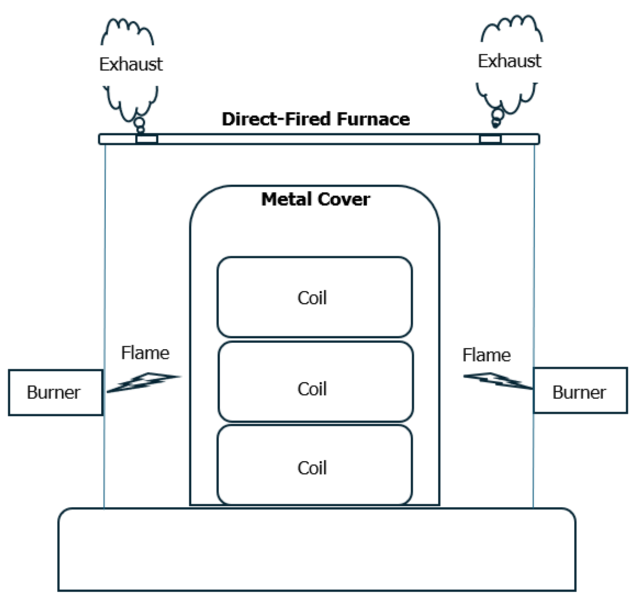
5.10 Batch Annealing Furnaces

No. 6 Batch Annealing furnaces at CCIHE has a collective MMBtu/hr firing rate high enough to yield a combined NO_X PTE of greater than 25 tpy. The No. 6 Batch Annealing furnaces at CCIHE consists of 17 individual multi-coil stack furnaces, 8 individual single-coil stack furnaces, and one hydrogen single-coil stack furnace each with a firing rate that would not have a NO_X PTE greater than 25 tpy.

The batch annealing furnaces are portable cylindrical furnaces that are set over the top of a “stack” of metal coils with a metal cover (or “can”) between the coils and the furnace. The cans are filled with an inert blanketing HNX gas (or H2 for the single unit) that protects the coils and helps distribute heat from the furnace burners to evenly bake the coils. In the case of multi-coil stack units, the portable cover is rectangular and sits over a base with 5 cans or coil stacks inside. The direct-fired furnaces consist of 10 burners per single-coil stack or 10 burners for multi-coil stack furnaces with open spiral/flat flames that burn parallel with the walls of the furnace inside the annular space between the furnace wall and the cans. Exhaust gases for each furnace exhaust to either 2 or 4 passive exhaust ports along the top edge of the furnace with mechanical counterweighted flaps over the discharge to maintain a static furnace pressure. A simplified cross section of a single-stack furnace is shown in Figure 5-1 below.

As described above, these units each have a NO_X PTE less than 25 tpy and are unable to be tested. Consequently, add-on control devices are not feasible. This is affirmed by the following statement in the current Title V Renewal Permit ATSD: *The NO_X emission factor for the No. 6 batch anneal furnace has not been tested. IDEM Compliance and Enforcement Branch has determined that a one-time test on the NO_X emission factor of the No. 6 Batch Anneal Furnace would not be possible.*

Figure 5-1. Simplified Schematic of Direct-Fired Batch Annealing Furnace



5.10.1 Step 1 – Identify All Control Options

The following technologies appear to be generally available for controlling NO_X emissions from the batch annealing furnaces:

- SCR
- SNCR
- LNB

The technical feasibility of each of these options is discussed in Step 2 below.

5.10.2 Step 2 – Eliminate Technically Infeasible Control Options

5.10.2.1 SCR AND SNCR

As described above and illustrated in the figure, it is technically infeasible to capture emissions from each of the individual batch annealing furnaces. Each furnace has several exhaust openings, and the emission unit group consists of 26 furnaces. Accordingly, CCIH considers installation of post-combustion controls such as SCR and SNCR to be technically infeasible.

5.10.2.2 LNBs

CCIH has used furnace tune-up burner data from both the Middletown Works and Cleveland Works to establish an estimated 0.10 lb NO_X/MMBtu emission factor, which is often considered as "inherently low NO_X." Furthermore, the EU group consists of several hundred burners. Therefore, it can be inherently assumed that installed new burners that achieve even the lowest possible lb NO_X/MMBtu emission rate would not be cost effective. Therefore, CCIH assumes that LNBs are not a realistic option and are not considered further in this analysis.

5.10.3 Step 3 – Rank Remaining Control Options

There are no remaining control options for the batch annealing furnaces.

5.10.4 Step 4 – Evaluation of the Most Effective Control Option

There are no remaining control options for the batch annealing furnaces.

5.10.5 Step 5 – Select RACT

CCIH proposes the following operational restrictions as RACT:

1. Conduct tune-ups on the burners as required by the Boiler MACT.
2. Limit the fuel used in the batch annealing furnaces to NG only.
3. Install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices for the control of the NO_X emissions from the unit.

Note that CCIH has not proposed a numerical limit for NO_X RACT. As is evident by the process description and accompanying figures in the introduction to Section 5.16., as well as discussed in the stack test feasibility letter provided by EQM in Appendix D, it is not feasible to perform a stack test on the batch annealing furnaces. Thus, there is no baseline emissions test from which a numerical lb NO_X/MMBtu NO_X emission limit may be derived. However, CCIH is confident that the combustion practices described above are sufficient to ensure NO_X emissions from the batch annealing furnaces will remain at minimal levels.

6. SUMMARY OF RACT DETERMINATIONS

A summary of the proposed RACT determinations for each source is presented in Table 6- below.

Table 6-1. Summary of Proposed RACT Determinations

Emission Unit	Proposed RACT Determination
Boilers 6-8	• NO_X RACT Trigger of 635.2 tpy, combined, enforceable on a 12-month rolling average, requiring a new RACT analysis within 1 year of exceeding the trigger • Conduct tune-ups on the burners as required by the Boiler MACT, when burning less than 90% BFG by volume • Limit the fuel used to NG or BFG • Install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices for the control of the NO_X emissions from the unit
Boilers 501-504	• Limit the fuel used to no less than 90% BFG by volume per year per boiler • Install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices for the control of the NO_X emissions from the unit
Site-wide Boiler Fleet	• Limit total heat input to no less than 50% BFG during the ozone season.
Blast Furnaces IH3, IH4 and IH7	• <u>Stoves</u>: Operational restriction of no less than 90% BFG by volume on a rolling 30-operating day basis. An operating day is defined as any calendar day with 12 hours of more during which wind is being added to the furnace and the top pressure of the furnace is greater than 5 pounds per square inch (psi). • <u>Casthouses</u>: No technically feasible NO_X control options • <u>Flare</u>: Maintain and operate the flare in accordance with the manufacturer's specifications and with good operating practices for the control of the NO_X emissions from the unit.
BOF #1, #2, #50 and #60	• <u>BOF Vessels</u>: No technically feasible NO_X control options • <u>Ladle Preheaters</u>: Continue to operate inherently low NO_X burners
2SM No. 2 Galvanizing Line	• Conduct tune-ups on the burners as required by the Boiler MACT • Limit the fuel used to NG only • Install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices for the control of the NO_X emissions from the unit
Recycle Plant	• No technically feasible NO_X control options
Lime Plant Kilns	• Install, maintain and operate the kiln burners in accordance with the manufacturer's specifications and with good operating practices for the control of the NO_X emissions from the unit

Emission Unit	Proposed RACT Determination
Hot Strip Mill Reheat Furnaces	#4 WBF • Limit the fuel used to NG only Install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices for the control of the NO_X emissions from the unit #5 WBF and #6 WBF • NO_X RACT Trigger of 569.9 tpy, combined, enforceable on a 12-month rolling average, requiring a new RACT analysis within 1 year of exceeding the trigger • Limit the fuel used to NG only • Install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices for the control of the NO_X emissions from the unit
No. 3 Continuous Annealing Line (CAL)	• Conduct tune-ups on the burners as required by the Boiler MACT • Limit the fuel used to NG only • Install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices for the control of the NO_X emissions from the unit
Batch Annealing Furnaces	• Conduct tune-ups on the burners as required by the Boiler MACT • Limit the fuel used to NG only • Install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices for the control of the NO_X emissions from the unit

APPENDIX A. COST CALCULATIONS

Estimated Average Cost ($/ton) of Burner Replacement

No. 2 Galvanizing Line (P022 Zinc Galv Twin)

ASSUMPTIONS

Parameter	Value	Units	Basis
Cost Year	2024		
Equipment Life	15	yrs	US EPA OAQPS
Annual Interest Rate	8.5	%	https://www.federalreserve.gov/releases/h15/

NO_X REDUCTION CALCULATIONS

Parameter	Value	Units	Basis
NO_X Removed (PTE Basis)	19.06	tons/yr	Maximum capacity, assuming 8,760 hr/yr of operation and multiplied by the delta of baseline and new emission factors
Furnace Capacity	200	MMBtu/hr	Title V Permit Basis
Baseline Emission Factor	0.112	lb NO_X/MMBtu	Title V Permit Basis (173.5 lb/MMscf for 49.65 MMBtu galvanizing furnace; 100 lb/MMscf for 150 MMBtu galvanizing furnace)
New Emission Factor	0.09	lb NO_X/MMBtu	Proposed Presumptive NO_X RACT Limit

TOTAL CAPITAL INVESTMENT

Parameter	Value	Basis
Purchased Equipment Cost	$ 1,075,250	Vendor quote of $8,500/burner for 110 burners (with 15% contingency for spares)
Engineering/Supervision Cost	$ 107,525	Conservative estimate of 10% of PEC
Installation Cost	$ 376,338	Estimated approximately 35% of PEC per vendor recommendation
Total Capital Investment, TCI	$ 1,559,113	PEC + Installation + Engineering / Supervision Cost

TOTAL ANNUAL COSTS

Parameter	Value	Units	Basis
Direct Annual Costs			
Annual Maintenance Costs	$ -		
Annual Operator Labor Cost	$ -		
Total direct annual cost, DAC	$ -		
Indirect Annual Costs			
Annual Administrative Cost	$ 31,182		2% of TCI
Property Tax	$ 15,591		1% of TCI
Insurance	$ 15,591		1% of TCI
IDAC and TAC			
Capital Recovery, CR	$ 187,749		CR = CRF x TCI
Capital recovery factor, CRF	0.12		CRF = i (1+ i)n/(1+ i)n - 1; where n = Equipment Life and i= Interest Rate
Total Indirect Annual Costs, IDAC	$ 250,114		IDAC = sum of Annual Administrative Cost Property Tax Insurance Capital Recovery, CR
Total Annual Cost, TAC	**$ 250,114**		**TAC = DAC + IDAC**

COST EFFECTIVENESS

Annual Cost (NO_X removed)

	Value	Units	Basis
PTE Basis	$ 13,123.54	$/ton	TAC/NO_X Removed

Estimated Average Cost ($/ton) of Burner Replacement

80" Hot Strip Mill (WBF #4)

ASSUMPTIONS

Parameter	Value	Units	Basis
Cost Year	2024		
Equipment Life	5	yrs	US EPA OAQPS
Annual Interest Rate	8.5	%	https://www.federalreserve.gov/releases/h15/

NO_X REDUCTION CALCULATIONS

Parameter	Value	Units	Basis
NO_X Removed (PTE Basis)	157.68	tons/yr	Maximum capacity, assuming 8,760 hr/yr of operation and multiplied by the delta of baseline and new emission factors
Furnace Capacity	720	MMBtu/hr	Title V Permit
Baseline Emission Factor	0.140	lb NO_X/MMBtu	November 2023 test at max capacity (685 MMBtu/hr)
New Emission Factor	0.09	lb NO_X/MMBtu	Proposed Presumptive NO_X RACT Limit

TOTAL CAPITAL INVESTMENT

Parameter	Value	Basis
Purchased Equipment Cost Engineering/Supervision Cost	$ 1,700,000	Total cost for equipment, design, and engineering from Bloom Engineering. Does not include flame safety upgrade and installation.
Installation Cost	$ 2,344,214	Internal analysis from reheat furnace engineering group at CCMW, scaled up from 598 MMBtu/hr (CCMW) to 720 MMBtu/hr to account for larger furnace
Total Capital Investment, TCI	$ 4,044,214	PEC + Engineering/Supervision + Installation Cost

TOTAL ANNUAL COSTS

Parameter	Value	Units	Basis
Direct Annual Costs			
Annual Maintenance Costs	$ -		
Annual Operator Labor Cost	$ -		
Total direct annual cost, DAC	$ -		
Indirect Annual Costs			
Annual Administrative Cost	$ 80,884		2% of TCI
Property Tax	$ 40,442		1% of TCI
Insurance	$ 40,442		1% of TCI
IDAC and TAC			
Capital Recovery, CR	$ 1,026,283		CR = CRF x TCI
Capital recovery factor, CRF	0.2538		CRF = i (1+ i)n/(1+ i)n - 1; where n = Equipment Life and i= Interest Rate
Total Indirect Annual Costs, IDAC	$ 1,188,052		IDAC = sum of Annual Administrative Cost Property Tax Insurance Capital Recovery, CR
Total Annual Cost, TAC	**$ 1,188,052**		**TAC = DAC + IDAC**

COST EFFECTIVENESS

Annual Cost (NO_X removed)	Value	Units	Basis
PTE Basis	$ 7,534.57	$/ton	TAC/NO_X Removed

Estimated Average Cost ($/ton) of Burner Replacement

80" Hot Strip Mill (WBF #5)

ASSUMPTIONS

Parameter	Value	Units	Basis
Cost Year	2024		
Equipment Life	5	yrs	US EPA OAQPS
Annual Interest Rate	8.5	%	https://www.federalreserve.gov/releases/h15/

NO_X REDUCTION CALCULATIONS

Parameter	Value	Units	Basis
NO_X Removed (PTE Basis)	543.53	tons/yr	Maximum capacity, assuming 8,760 hr/yr of operation and multiplied by the delta of baseline and new emission factors
Furnace Capacity	686	MMBtu/hr	Title V Permit Basis
Baseline Emission Factor	0.271	lb NO_X/MMBtu	September 2023 test at max capacity (652 MMBtu/hr)
New Emission Factor	0.09	lb NO_X/MMBtu	Proposed Presumptive NO_X RACT Limit
NO_X Removed (Actual Operations)	156.64	tons/yr	Maximum average firing rate, assuming 8,760 hr/yr of operation and multiplied by the delta of baseline and new emission factors
Firing Rate (Actual Operations)	328.1	MMBtu/hr	Jan 2016 to Mar 2016 average firing rate extrapolated to annual operation
RACT Trigger	**286.0**	**tpy NOx**	NOx emissions based on Jan 2016 to Mar 2016 average firing rate extrapolated to annual operation
Baseline Emission Factor	0.199	lb NO_X/MMBtu	Average of March 2009, March 2014, and Nov 2018 tests at normal operating conditions
New Emission Factor	0.09	lb NOX/MMBtu	Proposed Presumptive NO_X RACT Limit

TOTAL CAPITAL INVESTMENT

Parameter	Value	Basis
Purchased Equipment Cost Engineering/Supervision Cost	$ 2,150,000	Total cost for equipment, design, and engineering from Bloom Engineering. Does not include flame safety upgrade and installation.
Installation Cost	$ 2,232,213	Internal analysis from reheat furnace engineering group at CCMW, scaled up from 598 MMBtu/hr (CCMW) to 686 MMBtu/hr to account for larger furnace
Total Capital Investment, TCI	$ 4,382,213	PEC + Engineering/Supervision + Installation Cost

TOTAL ANNUAL COSTS

Parameter	Value	Units	Basis
Direct Annual Costs			
Annual Maintenance Costs	$ -		
Annual Operator Labor Cost	$ -		
Total direct annual cost, DAC	$ -		
Indirect Annual Costs			
Annual Administrative Cost	$ 87,644		2% of TCI
Property Tax	$ 43,822		1% of TCI
Insurance	$ 43,822		1% of TCI
IDAC and TAC			
Capital Recovery, CR	$ 1,112,056		CR = CRF x TCI
Capital recovery factor, CRF	0.2538		CRF = i (1+ i)n/(1+ i)n - 1; where n = Equipment Life and i= Interest Rate
Total Indirect Annual Costs, IDAC	$ 1,287,344		IDAC = sum of Annual Administrative Cost Property Tax Insurance Capital Recovery, CR
Total Annual Cost, TAC	**$ 1,287,344**		**TAC = DAC + IDAC**

COST EFFECTIVENESS

Annual Cost (NO_X removed)	Value	Units	Basis
PTE Basis	$ 2,368.49	$/ton	TAC/NO_X Removed
Max Actuals Basis	$ 8,218.70	$/ton	

Estimated Average Cost ($/ton) of Burner Replacement

80" Hot Strip Mill (WBF #6)

ASSUMPTIONS

Parameter	Value	Units	Basis
Cost Year	2024		
Equipment Life	5	yrs	US EPA OAQPS
Annual Interest Rate	8.5	%	https://www.federalreserve.gov/releases/h15/

NO_X REDUCTION CALCULATIONS

Parameter	Value	Units	Basis
NO_X Removed (PTE Basis)	549.54	tons/yr	Maximum capacity, assuming 8,760 hr/yr of operation and multiplied by the delta of baseline and new emission factors
Furnace Capacity	686	MMBtu/hr	Title V Permit Basis
Baseline Emission Factor	0.273	lb NO_X/MMBtu	Average of Feb 2014 and Sep 2023 tests that were conducted at or near max operating conditions
New Emission Factor	0.09	lb NO_X/MMBtu	Proposed Presumptive NO_X RACT Limit
NO_X Removed (Actual Operations)	155.84	tons/yr	Maximum average firing rate, assuming 8,760 hr/yr of operation and multiplied by the delta of baseline and new emission factors
Firing Rate (Actual Operations)	324.9	MMBtu/hr	Apr to Jun 2015 average firing rate extrapolated to annual operation
RACT Trigger	**283.9**	**tpy NOx**	NOx emissions based on Apr to Jun 2015 average firing rate extrapolated to annual operation
Baseline Emission Factor	0.200	lb NO_X/MMBtu	Average of March 2009 and Nov 2018 tests at normal operating conditions
New Emission Factor	0.09	lb NO_X/MMBtu	Proposed Presumptive NO_X RACT Limit

TOTAL CAPITAL INVESTMENT

Parameter	Value	Basis
Purchased Equipment Cost	$ 2,150,000	Total cost for equipment, design, and engineering from Bloom Engineering. Does not include flame safety upgrade and installation.
Engineering/Supervision Cost		
Installation Cost	$ 2,232,213	Internal analysis from reheat furnace engineering group at CCMW, scaled up from 598 MMBtu/hr (CCMW) to 686 MMBtu/hr to account for larger furnace
Total Capital Investment, TCI	$ 4,382,213	PEC + Engineering/Supervision + Installation Cost

TOTAL ANNUAL COSTS

Parameter	Value	Units	Basis
Direct Annual Costs			
Annual Maintenance Costs	$ -		
Annual Operator Labor Cost	$ -		
Total direct annual cost, DAC	$ -		
Indirect Annual Costs			
Annual Administrative Cost	$ 87,644		2% of TCI
Property Tax	$ 43,822		1% of TCI
Insurance	$ 43,822		1% of TCI
IDAC and TAC			
Capital Recovery, CR	$ 1,112,056		CR = CRF x TCI
Capital recovery factor, CRF	0.2538		CRF = i (1+ i)n/(1+ i)n - 1; where n = Equipment Life and i= Interest Rate
Total Indirect Annual Costs, IDAC	$ 1,287,344		IDAC = sum of Annual Administrative Cost Property Tax Insurance Capital Recovery, CR
Total Annual Cost, TAC	**$ 1,287,344**		**TAC = DAC + IDAC**

COST EFFECTIVENESS

Annual Cost (NO_X removed)

	Value	Units	Basis
PTE Basis	$ 2,342.60	$/ton	TAC/NO_X Removed
Max Actuals Basis	$ 8,260.60	$/ton	

Estimated Average Cost ($/ton) of Burner Replacement

No. 3 Continuous Annealing Line

ASSUMPTIONS

Parameter	Value	Units	Basis
Cost Year	2024		
Equipment Life	15	yrs	US EPA OAQPS (Assumed for process heaters)
Annual Interest Rate	8.5	%	https://www.federalreserve.gov/releases/h15/

NO_X REDUCTION CALCULATIONS

Parameter	Value	Units	Basis
NO_X Removed (PTE Basis)	44.56	tons/yr	Maximum capacity, assuming 8,760 hr/yr of operation and multiplied by the delta of baseline and new emission factors
Furnace Capacity	82.7	MMBtu/hr	Based on current burner configuration per Bloom; Title V permit basis is 108 MMBtu/hr
Baseline Emission Factor	0.213	lb NO_X/MMBtu	Calculated based on Bloom estimated emissions for current burner configuration
New Emission Factor	0.09	lb NO_X/MMBtu	Proposed Presumptive NO_X RACT Limit

TOTAL CAPITAL INVESTMENT

Parameter	Value	Basis
Purchased Equipment Cost	$ 1,419,215	Vendor quote for burners (with 15% contingency for spares)
Engineering/Supervision Cost	$ 141,922	Conservative estimate of 10% of PEC
Installation Cost	$ 496,725	Estimated approximately 35% of PEC per vendor recommendation
Total Capital Investment, TCI	$ 2,057,862	PEC + Installation + Engineering/Supervision Cost

TOTAL ANNUAL COSTS

Parameter	Value	Units	Basis
Direct Annual Costs			
Annual Maintenance Costs	$ -		
Annual Operator Labor Cost	$ -		
Total direct annual cost, DAC	$ -		
Indirect Annual Costs			
Annual Administrative Cost	$ 41,157		2% of TCI
Property Tax	$ 20,579		1% of TCI
Insurance	$ 20,579		1% of TCI
IDAC and TAC			
Capital Recovery, CR	$ 247,809		CR = CRF x TCI
Capital recovery factor, CRF	0.1204		CRF = i (1+ i)n/(1+ i)n - 1; where n = Equipment Life and i= Interest Rate
Total Indirect Annual Costs, IDAC	$ 330,123		IDAC = sum of Annual Administrative Cost Property Tax Insurance Capital Recovery, CR
Total Annual Cost, TAC	**$ 330,123**		**TAC = DAC + IDAC**

COST EFFECTIVENESS

Annual Cost (NO_X removed)

	Value	Units	Basis
PTE Basis	$ 7,409.18	$/ton	TAC/NO_X Removed

Estimated Average Cost ($/ton) of Burner Replacement

Boilers #6 - #8

ASSUMPTIONS

Parameter	Value	Units	Basis
Cost Year	2024		
Equipment Life	15	yrs	US EPA OAQPS
Annual Interest Rate	8.5	%	https://www.federalreserve.gov/releases/h15/

NO_X REDUCTION CALCULATIONS

Parameter	Value	Units	Basis
PTE Basis			
Total NO_X Removed (PTE Basis) - Boilers #6 - #8	1,050	tons/yr	Maximum capacity, assuming 8,760 hr/yr of operation and multiplied by the delta of baseline and new emission factors
Boilers #6 - #8 Total Maximum Capacity	1,998	MMBtu/hr	Title V permit capacities for each boiler; Cleveland-Cliffs notes that the maximum operating capacity for each boiler is below the permitted capacity as noted in the AECOM study. Refer to the RACT study for detailed information.
Baseline Emission Factor	0.20	lb NO_X/MMBtu	AECOM Study
New Emission Factor	0.08	lb NO_X/MMBtu	Vendor guarantee for LNB + FGR, which is a more viable option than LNB + OFA due to necessity of removing water-wall tubing for OFA on Units 6 & 7.
RACT Trigger Based on Actual Operations			
Total NOx Removed (Actual Operations) - Boilers #6 - #8	381.11	tons/yr	Maximum capacity, assuming 8,760 hr/yr of operation and multiplied by the delta of baseline and new emission factors
Total Firing Rate (Actual Operations) - Boilers #6 - #8	725	MMBtu/hr	1st Half 2022 (i.e., Jan-Jun) operation for Boilers 6-8, combined, extrapolated to annual operation
RACT Emissions Trigger (combined for Boilers 6-8)	**635.2**	**tpy NOx**	**Total Firing Rate (MMBtu/hr) x 8,760 hr/yr x 0.20 lb NOx/MMBtu / 2,000 lb/ton**

TOTAL CAPITAL INVESTMENT

Parameter	Value	Units	Basis
Total Capital Investment, TCI	$ 13,700,000		Boiler #6 - AECOM analysis, installed LNB + FGR ($4,525,000) Boiler #7 - AECOM analysis, installed LNB + FGR ($4,525,000) Boiler #8 - AECOM analysis, installed cost for LNB + OFA ($4,650,000)

TOTAL ANNUAL COSTS

Parameter	Value	Units	Basis
Direct Annual Costs			
Annual Maintenance Costs Annual Operator Labor Cost	$ 120,000		Boiler #6-#7 AECOM analysis, annual O&M for FGR ($60,000 x 2 units); cost analysis conservatively assumes there are no direct annual costs for Boiler #8
Total direct annual cost, DAC	$ 120,000		
Indirect Annual Costs			
Annual Administrative Cost	$ 274,000		2% of TCI
Property Tax	$ 137,000		1% of TCI
Insurance	$ 137,000		1% of TCI
IDAC and TAC			
Capital Recovery, CR	$ 1,649,760		CR = CRF x TCI
Capital recovery factor, CRF	0.1204		CRF = i (1+ i)n/(1+ i)n - 1; where n = Equipment Life and i= Interest Rate
Total Indirect Annual Costs, IDAC	$ 2,197,760		IDAC = sum of Annual Administrative Cost Property Tax Insurance Capital Recovery, CR
Total Annual Cost, TAC	**$ 2,317,760**		**TAC = DAC + IDAC**

COST EFFECTIVENESS

Annual Cost (NO_X removed)

	Value	Units	Basis
PTE Basis - Per Boiler	$ 2,207.08	$/ton	TAC/NO_X Removed
Actual Operations	$ 6,081.53	$/ton	

APPENDIX B. VENDOR QUOTES

#2 CGL

The #2 line on the west side has cold air burners on the first 3 zones of the radiant tube section. Final 5 zones employ the Bloom 2370-F ultra-low NOx recuperated burner.

The burners in the first 3 zones are about 35% efficient and the recuperated burners are about 62-66% efficient, dependent on operating conditions.

The #2 CGL at West side operation furnace construction was circa mid-1960s. The line has straight through radiant tubes with cold air burners.

Circa 2005 the #3 line had the entire radiant tube section removed and replaced with "U" shaped tubes to reduce the number of radiant tubes and increase efficiency. The shell casing was also in bad disrepair and needed replacement as well.

The final 5 zones of the #2 line have approximately 61 burners. The first 3 zones have about 50 or so. The price for these burners would be very similar to that of the #3CAL line in the $8,500 per piece range with a bulk buy.

The Nox, again, will be similar to that 3CAL with a Nox emission of well under .09 #/MMBtu.

Should you have any questions, comments, or concerns, please do not hesitate to contact us.

Best regards,

Scott E. Brown
Director – Sales & Business Development
Bloom Engineering Company, Inc.
Cell: 330-730-0096
Work: 412-653-3500
sbrown@bloomeng.com
www.bloomeng.com

BLOOM
ENGINEERING

80" Hot Strip Mill (WBF #4-#6)

NOX emission calculation FOR REHEAT FURNACE N° 4 (UTILIZING BLOOM MODEL 1610)

The following calculation is based on a Potential to Emit (POE) basis. For this calculation, the parameters of the calculation, for both the existing burners Bloom Model 1500 burners and the Bloom Model 1610 burners that are being proposed.

Provided are the estimated emissions as well as the guaranteed values.

Calculation Parameters
The following operating parameters are what the NOx emission calculations are based upon:

Furnace Temperature °C (°F)	1275°C (2320°F)
Preheated Air Temperature °C (°F)	450°C (842°F)
Stoichiometric Percentage	λ = 1.10

The price for a full complement of burners and necessary equipment, not including flame safety upgrades will be approximately $1,700,000.00 for all required engineering, design, and engineering. This does not include installation.

NOX emission calculation FOR REHEAT FURNACE N° 5 & N° 6 (UTILIZING BLOOM MODEL 1610)

The following calculation is based on a Potential to Emit (POE) basis. For this calculation, the parameters of the calculation, for both the existing burners Bloom Model 1200 burners and the Bloom Model 1610 being proposed.

Provided are the estimated emissions as well as the guaranteed values.

Calculation Parameters
The following operating parameters are what the NOx emission calculations are based upon:

Furnace Temperature °C (°F)	1275°C (2320°F)
Preheated Air Temperature °C (°F)	450°C (842°F)
Stoichiometric Percentage	λ = 1.10

The price for a full complement of burners and necessary equipment, not including flame safety upgrades will be approximately $2,150,000.00 per furnace for all required engineering, design, and engineering. This does not include installation.

We believe this is the information you need and please do not hesitate to contact us.

As the engineering is proceeding, Bloom will b at your site late next week if you need discussion.

Should you have any questions, comments, or concerns, please do not hesitate to contact us.

Best regards,

Scott E. Brown
Director – Sales & Business Development
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BLOOM ENGINEERING

#3 CAL

From: Brown, Scott <SBrown@bloomeng.com>
Sent: Thursday, August 8, 2024 9:09 AM
To: Wolters, Brian T <Brian.Wolters@clevelandcliffs.com>
Cc: Church, David <dchurch@bloomeng.com>; Beichner, Frank <fbeichner@bloomeng.com>; Cassler, Alan <acassler@bloomeng.com>
Subject: [EXTERNAL] RE: September 2022 4, 5, and 6 Furnace Analysis - 3CAL
Importance: High

Brian,

Regarding the 3CAL necessary information, we can offer the following:
There are 220 burners on the 3CAL furnace with Bloom supplying 80 replacements.
Of the 80 replacements, there are 71 burners installed in the line with the remaining 9 still be stored on the vicinity of the #5 CGL.
From discussions with the crew(s) from 3 CAL the burners installed are :

1. All 14 burners in the GJC section. This section is 100% Bloom equipment.
2. 43 burners in the soak section have been replaced.

3. 14 burners in the heat section have been replaced.
4. Total of 71 Burners replaced

As an average, a full furnace of the Bloom 2370s will give you a Nox reduction of 70% across the furnace and well below the .09 #/MMBtu.
The numbers given by Bloom are guaranteed numbers on the Nox.

Regarding pricing:

For the heating section, the Bloom 2370 Ultra Low NOx burner will have a selling price (delivered to site) of approximately $8,500.00 per burner for 7" OD tube and $8,200 per burner for the 6" OD tubes. when ordered in bulk. We would anticipate that you would need a quantity of 56 of the 7" OD radiant tube burners and 78 of the 6" OD burners.

For the soaking section, the Bloom 2370 Ultra Low NOx burner will have a selling price (delivered to site) of approximately $7,900.00 per burner when ordered in bulk. We would anticipate that you would need a quantity of 15.

For the Gas Jet Cooling, the Bloom 2370 Ultra Low NOx burner will have a selling price (delivered to site) of approximately $8,500.00 per burner when ordered in bulk. We would anticipate that you would need a quantity of 0 as all these burners have been replaced. With the installed Bloom burners currently and the above quantities would give a total of 220 burners in the line, which meshes with the original design.
Should you have any questions, comments, or concerns, please do not hesitate to contact us.

Best regards,

Scott E. Brown
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Boilers 6-8

Refer to AECOM Study in **Appendix D**.

APPENDIX C. STACK TESTS

No. 4 - Walking Beam Furnace
No. 5 - Walking Beam Furnace
No. 6 - Walking Beam Furnace

March 2009

GE Energy

Paul Coleman
Project Manager

ISO 9001
Registered
Quality System

GASEOUS EMISSIONS COMPLIANCE STUDY

Performed At

ArcelorMittal Steel USA
Nos. 4, 5 and 6 Walking Beam Furnaces
East Chicago, Indiana

Test Dates

March 3, 5 and 6, 2009

Report No.

GE Energy Management Services, Inc. Report M22G0636B

Report Submittal Date

April 13, 2009

GE Energy Management Services, Inc.
1950 Griffith Boulevard, Suite A
Griffith, IN 46319
USA

T (219) 838-6082
F (219) 838-6083

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GE Energy

CERTIFICATION SHEET

Having reviewed the test program described in this report, I hereby certify the data, information, and results in this report to be accurate and true according to the methods and procedures used.

Data collected under the supervision of others is included in this report and is presumed to have been gathered in accordance with recognized standards.

GE ENERGY MANAGEMENT SERVICES, INC.

Frank H. Jarke

Frank H. Jarke
Quality Assurance Manager

GASEOUS EMISSIONS COMPLIANCE STUDY
Performed For
ArcelorMittal Steel USA
At The
Nos. 4, 5 and 6 Walking Beam Furnaces
East Chicago, Indiana
March 3, 5 and 6, 2009

1.0 INTRODUCTION

GE Energy Management Services, Inc., (GE Energy) performed a gaseous emissions compliance test program at the Nos. 4, 5 and 6, Walking Beam Furnaces of ArcelorMittal Steel USA in East Chicago, Indiana on March 3, 5 and 6, 2009. The tests were authorized by and performed for ArcelorMittal Steel USA

The purpose of this test program was to determine oxides of nitrogen (NO_x) emission rates during normal operating conditions.

1.1 Project Contact Information

Location	Address	Contact
Test Facility	ArcelorMittal Steel USA 3210 Watling Street East Chicago, Indiana 46312	Mr. Tom Maicher 219-391-2133 (phone) 219-391-3211 (fax) thomas.maicher@arcelormittal.com
Testing Company Representative	GE Energy Management Services, Inc. 1950 Griffith Boulevard, Suite A Griffith, Indiana 46319	Mr. Paul Coleman Project Manager 219-838-6082 (phone) 219-838-6083 (fax) paul.coleman@ge.com

The tests were conducted by G. Kvarta, G. Lewis, J. Merryman, J. Miller, E. Peterson, N. Smith, W. Zoeteman and P. Coleman of GE Energy.

Mr. Glen Schwartz of URS observed the testing.

2.0 SUMMARY OF RESULTS

This test program consisted of three (3) sixty-minute NO_x tests on the Walking Beam Furnace 4, 5 and 6 exhaust test locations. The average emission rates were:

Parameter		Walking Beam Furnace 4	Walking Beam Furnace 5	Walking Beam Furnace 6
Nitrogen Oxide (NO_x)	lb/hr	23.84	72.59	51.79
Nitrogen Oxide (NO_x)	lb/MMBtu	0.130*	0.198	0.170
Nitrogen Oxide (NO_x)	lb/million ft^3 natural gas	110.38	217.58	192.95
Fuel Usage	Million ft^3 natural gas/hr	0.221	0.331	0.267

* Flow weighted average.

Complete test results summaries are tabulated and can be found in Section 6.0.

3.0 DISCUSSION OF RESULTS

No problems were encountered with the testing equipment during the test program. Source operation appeared normal during the entire test program. Unit operating data was recorded by plant personnel and is appended to the report.

Walking Beam Furnace 4 has two exhaust stacks, north and south. The total emission rate (lb/hr) is the combined emissions of the north and south stacks. The pounds per million Btu results were based on volumetric flow weighted average of the exhaust stacks.

Sampling for the Walking Beam Furnaces 5 and 6 was conducted at the exhaust breeching test locations. Site acceptability tests were conducted at each breeching as outlined in USEPA Method 1. The results of these tests are appended. The results show that these test locations are suitable test locations.

A standard fuel factor of 8710 dry standard cubic feet per million Btu (dscf/MMBtu) for natural gas was used to determine the emission rate on a pounds per million Btu (lb/MMBtu) basis.

4.0 SAMPLING AND ANALYSIS PROCEDURES

All testing, sampling, analytical, and calibration procedures used for this test program were performed in accordance with the methods presented in the following sections. Where applicable, the *Quality Assurance Handbook for Air Pollution Measurement Systems*, Volume III, Stationary Source Specific Methods, USEPA 600/R-94/038c, September 1994 was used to supplement procedures.

No. 4 - Walking Beam Furnace
No. 5 - Walking Beam Furnace
No. 6 - Walking Beam Furnace

February-March 2014

Gaseous Emissions Compliance Test Report

ArcelorMittal USA LLC
ArcelorMittal Indiana Harbor East
No. 4 Walking Beam Furnaces,
No. 5 Walking Beam Furnace, and
No. 6 Walking Beam Furnace
East Chicago, Indiana
Project No. M140709
February 28, March 10 and 14, 2014

Gaseous Emissions Compliance Test Report

ArcelorMittal USA LLC
ArcelorMittal Indiana Harbor East
No. 4 Walking Beam Furnaces, No. 5 Walking Beam Furnace, and No. 6 Walking Beam Furnace
East Chicago, Indiana
February 28, March 10 and 14, 2014

Report Submittal Date
April 11, 2014

Project No. M140709

888 Industrial Drive
Elmhurst, Illinois 60126
630-993-2100

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1.0 EXECUTIVE SUMMARY

MOSTARDI PLATT conducted a gaseous emissions compliance test program for ArcelorMittal USA LLC on February 28, March 10 and 14, 2014 on the No. 4 Walking Beam Furnaces, No. 5 Walking Beam Furnace, and No. 6 Walking Beam Furnace at the ArcelorMittal Indiana Harbor East facility in East Chicago, Indiana. This report summarizes the results of the test program and test methods used.

The test locations, test dates, and test parameters are summarized below.

Test Locations	Test Dates	Test Parameters
No. 4 Walking Beam Furnaces	March 10 and 14, 2014	Nitrogen Oxide (NO_x), Carbon Dioxide (CO_2), Oxygen (O_2), and Volumetric Flow
No. 5 Walking Beam Furnace	March 14, 2014	NO_X, CO_2, O_2, and Volumetric Flow
No. 6 Walking Beam Furnace	February 28, 2014	NO_X, O_2, and Volumetric Flow

The purpose of the test program was to demonstrate emissions during normal operating conditions. Selected results of the test program are summarized below. A complete summary of emission test results follows the narrative portion of this report.

TEST RESULTS			
Test Location	**Test Date**	**Test Parameter**	**Emission Rate**
No. 4 Walking Beam Furnaces	3/10/14 and 3/14/14	NO_X	0.083 lb/mmBtu*
			28.81 lb/hr
			102.90 lb/mm ft^3 Natural Gas
No. 5 Walking Beam Furnace	3/14/14	NO_X	0.199 lb/mmBtu
			68.16 lb/hr
			147.47 lb/mm ft^3 Natural Gas
No. 6 Walking Beam Furnace	2/28/14	NO_X	0.274 lb/mmBtu
			131.23 lb/hr
			255.92 lb/mm ft^3 Natural Gas

*Flow weighted average

Operating data as provided by ArcelorMittal USA, LLC is included in Appendix A.

No. 4 - Walking Beam Furnace
No. 5 - Walking Beam Furnace
No. 6 - Walking Beam Furnace

November 2018

Gaseous Emissions Compliance Test Report

ArcelorMittal USA LLC
ArcelorMittal Indiana Harbor East
No. 4 Walking Beam Furnace,
No. 5 Walking Beam Furnace, and
No. 6 Walking Beam Furnace
East Chicago, Indiana
Project No. M184503
November 8, 9 and 15, 2018

Gaseous Emissions Compliance Test Report

ArcelorMittal USA LLC
ArcelorMittal Indiana Harbor East
No. 4 Walking Beam Furnace, No. 5 Walking Beam Furnace, and No. 6 Walking Beam Furnace
East Chicago, Indiana
November 8, 9 and 15, 2018

Report Submittal Date
December 13, 2018

Project No. M184503

Corporate Headquarters
888 Industrial Drive
Elmhurst, Illinois 60126
630-993-2100

Chicago, IL | Crown Point, IN | Concord, NC | Mendota Heights, MN | Denver, CO

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1.0 EXECUTIVE SUMMARY

MOSTARDI PLATT conducted a gaseous emissions compliance test program for ArcelorMittal USA LLC on November 8, 9 and 15, 2018 on the No. 4 Walking Beam Furnace, No. 5 Walking Beam Furnace, and No. 6 Walking Beam Furnace at the ArcelorMittal Indiana Harbor East facility in East Chicago, Indiana. This report summarizes the results of the test program and test methods used.

The test locations, test dates, and test parameters are summarized below.

TEST INFORMATION		
Test Locations	**Test Dates**	**Test Parameters**
No. 4 Walking Beam Furnace	11/9/18	Nitrogen Oxide (NO_x), Carbon Dioxide (CO_2), Oxygen (O_2), and Volumetric Flow
No. 5 Walking Beam Furnace	11/8/18	NO_X, CO_2, O_2, and Volumetric Flow
No. 6 Walking Beam Furnace	11/15/18	NO_X, CO_2, O_2, and Volumetric Flow

The purpose of the test program was to demonstrate emissions during normal operating conditions. Selected results of the test program are summarized below. A complete summary of emission test results follows the narrative portion of this report.

TEST RESULTS				
Test Location	**Test Date**	**Test Parameter**	**Emission Limit**	**Emission Rate**
No. 4 Walking Beam Furnace North Stack and South Stack	11/9/18	NO_X	357 lb/mm ft^3 Natural Gas	166.32 lb/mm ft^3 Natural Gas
No. 5 Walking Beam Furnace	11/8/18	NO_X	357 lb/mm ft^3 Natural Gas	138.29 lb/mm ft^3 Natural Gas
No. 6 Walking Beam Furnace	11/15/18	NO_X	357 lb/mm ft^3 Natural Gas	181.58 lb/mm ft^3 Natural Gas

*Flow weighted average

Operating data as provided by ArcelorMittal USA, LLC is included in Appendix A.

The identification of individuals associated with the test program is summarized below.

TEST PERSONNEL INFORMATION		
Location	**Address**	**Contact**
Test Facility	ArcelorMittal USA LLC ArcelorMittal Indiana Harbor East Chicago, Indiana	Mr. Michael Shimerdla Environmental Engineer, P.E. (219) 545-9184 (phone)
Testing Company Representative	Mostardi Platt 888 Industrial Drive Elmhurst, Illinois 60126	Mr. Stuart L. Burton (630) 993-2100 (phone) sburton@mp-mail.com

The test crew consisted of Messrs. B. Garcia, C. Buglio, H. Mendoza, P. Lyons and S. Burton of Mostardi Platt.

2.0 TEST METHODOLOGY

Emission testing was conducted following the methods specified in 40 CFR, Part 60, Appendix A. Schematics of the test section diagrams and sampling trains used are included in Appendix B and C, respectively. Calculation examples and nomenclature are included in Appendix D. Copies of analyzer printouts and field data sheets for each test run are included in Appendix E and F, respectively.

The following methodologies were used during the test program:

Method 1 Traverse Point Determination

Test measurement points were selected in accordance with Method 1. The characteristics of the measurement location are summarized below.

TEST POINT INFORMATION						
Location	**Stack Dimensions (Feet)**	**Area (Square Feet)**	**Upstream Diameters**	**Downstream Diameters**	**Test Parameter**	**Number of Sampling Points**
No. 4 Walking Beam Furnace North and South Stacks	5.5 (Diameter)	23.76	>0.5	>2.0	Volumetric Flow	16
					NO_x	12
No. 5 Walking Beam Furnace	8 by 12	96.00	>0.5	<2.0	Volumetric Flow	16
					NO_x	12
No. 6 Walking Beam Furnace	8 by 12	96.00	>0.5	<2.0	Volumetric Flow	16
					NO_x	12

Site acceptability tests were performed at the No. 5 Walking Beam Furnace and No. 6 Walking Beam Furnace test locations in 2009 and passed. The site acceptability tests are on file at the facility.

Method 2 Volumetric Flowrate Determination

Gas velocity was measured following Method 2, for purposes of calculating stack gas volumetric flow rate. S-type pitot tubes, differential pressure gauges, thermocouples and temperature readouts were used to determine gas velocity at each sample point at each test location. All of the equipment used was calibrated in accordance with the specifications of the Method. Calibration data are presented in Appendix G.

Method 3A Oxygen (O_2)/Carbon Dioxide (CO_2) Determination

Stack gas molecular weight was determined in accordance with Method 3A. Servomex analyzers were used to determine stack gas oxygen and carbon dioxide content and, by difference, nitrogen content. All of the equipment used was calibrated in accordance with the specifications of the Method and calibration data are included in Appendix G. Copies of the gas cylinder certifications are included in Appendix H.

Method 4 Moisture Determination

USEPA Method 4 was utilized to determine water (H_2O) content of the exhaust gas. 100 milliliters (ml) of water were added to each of the first two impingers, the third impinger was left empty, and the fourth impinger was charged with approximately 200 grams of silica gel. The impingers were placed in an ice bath to maintain the sampled gas passed through the silica gel impinger outlet below 68°F in order to increase the accuracy of the sampled dry gas volume measurement. The water volumes of the impinger train were measured and the silica gel was weighed before and after each test run to determine the mass of moisture condensed.

Each sample was extracted through a heated stainless-steel probe and filter assembly at a constant sample rate of approximately 0.75 cubic feet per minute, which was maintained throughout the course of the test run. A minimum of 21 dry standard cubic feet (dscf) are sampled for, each moisture run. After each run, a leak check of the sampling train was performed at a vacuum greater than the sampling vacuum to determine if any leakage had occurred during sampling. Following the leak check, the impingers were removed from the ice bath, water levels were measured, and the silica gel weight was recorded.

All of the equipment used was calibrated in accordance with the specifications of the Method. Copies of field data sheets are included in Appendix F. Calibration data are presented in Appendix G.

Method 7E Nitrogen Oxide (NO_X) Determination

Stack gas nitrogen oxide concentrations and emission rates were determined in accordance with Method 7E. A Thermo Scientific nitrogen oxide analyzer was used to determine nitrogen oxide concentrations, in the manner specified in the Method.

Stack gas was delivered to the analyzer via a Teflon® sampling line, heated to a minimum temperature of 250ºF. Excess moisture in the stack gas was removed using a refrigerated condenser. The entire system was calibrated in accordance with the Method, using certified calibration gases introduced at the probe, before and after each test run.

A list of calibration gases used and the results of all calibration and other required quality assurance checks can be found in Appendix G. Copies of calibration gas certifications can be found in Appendix H.

3.0 TEST RESULT SUMMARIES

ArcelorMittal USA, LLC ArcelorMittal Indiana Harbor East No. 4 Walking Beam Furnace Gaseous Summary											
				North Stack				South Stack			
Test No.	Date	Start Time	End Time	NO_x ppmvd	CO_2 % (dry)	O_2 % (dry)	Flowrate, DSCFM	NOx ppmvd	CO2 % (dry)	O2 % (dry)	Flowrate, DSCFM
1	11/09/18	12:25	13:30	68.7	6.4	9.3	69,308	87.3	6.9	8.8	60,767
2	11/09/18	13:50	15:44	64.8	6.3	9.6	59,824	86.6	6.3	9.6	56,211
3	11/09/18	16:00	17:23	61.2	4.2	13.2	39,785	89.5	5.3	11.4	52,114
Average				64.9	5.6	10.7	56,306	87.8	6.2	9.9	56,364

Emission Rate Summary

					North Stack		South Stack		Total			
Test No.	Date	Start Time	End Time	Fd Factor, dscf/MMBtu	O2 based NOx lb/MMBtu	NO_x lb/hr	O2 based NOx lb/MMBtu	NOx lb/hr	O2 based NOx lb/MMBtu *	NO_x lb/hr	Fuel Usage lb/MMscf natural gas/hr	NOx lb/MM scf natural gas
1	11/09/18	12:25	13:30	8,710.0	0.129	34.11	0.157	38.00	0.142	72.11	0.427	169.03
2	11/09/18	13:50	15:44	8,710.0	0.125	27.77	0.167	34.87	0.145	62.64	0.432	145.12
3	11/09/18	16:00	17:23	8,710.0	0.173	17.44	0.205	33.41	0.191	50.85	0.275	184.82
Average				8,710.0	0.142	26.44	0.176	35.43	0.159	61.87	0.378	166.32

* Flow weighted

ArcelorMittal USA, LLC ArcelorMittal Indiana Harbor East No. 5 Walking Beam Furnace Gaseous Summary							
Test No.	Date	Start Time	End Time	NO_x ppmvd	CO_2 % (dry)	O_2 % (dry)	Flowrate, DSCFM
1	11/08/18	10:50	12:07	118.3	8.9	4.9	58,510
2	11/08/18	12:20	14:48	171.7	9.2	4.8	73,064
3	11/08/18	15:02	16:15	157.1	9.3	4.4	76,642
Average				149.0	9.1	4.7	69,405

Emission Rate Summary

Test No.	Date	Start Time	End Time	Fd Factor, dscf/MMBtu	O2 based NOx lb/MMBtu	NO_x lb/hr	Fuel Usage lb/MMscf natural gas/hr	NOx lb/MM scf natural gas
1	11/08/18	10:50	12:07	8,710.0	0.161	49.59	0.445	111.38
2	11/08/18	12:20	14:48	8,710.0	0.232	89.87	0.539	166.74
3	11/08/18	15:02	16:15	8,710.0	0.207	86.26	0.631	136.74
Average				8,710.0	0.200	75.24	0.538	138.29

ArcelorMittal USA, LLC ArcelorMittal Indiana Harbor East No. 6 Walking Beam Furnace Gaseous Summary							
Test No.	Date	Start Time	End Time	NO_x ppmvd	CO_2 % (dry)	O_2 % (dry)	Flowrate, DSCFM
1	11/15/18	08:26	09:45	191.5	8.3	6.2	82,428
2	11/15/18	09:58	11:13	156.3	7.4	7.7	62,453
3	11/15/18	11:25	12:52	105.6	8.8	5.4	59,805
Average				151.1	8.2	6.4	68,229

Emission Rate Summary

Test No.	Date	Start Time	End Time	Fd Factor, dscf/MMBtu	O2 based NOx lb/MMBtu	NO_x lb/hr	Fuel Usage lb/MMscf natural gas/hr	NOx lb/MM scf natural gas
1	11/15/18	08:26	09:45	8,710.0	0.283	113.08	0.535	211.36
2	11/15/18	09:58	11:13	8,710.0	0.257	69.93	0.335	208.75
3	11/15/18	11:25	12:52	8,710.0	0.148	45.24	0.363	124.63
Average				8,710.0	0.229	76.08	0.411	181.58

No. 5 - Walking Beam Furnace
No. 6 - Walking Beam Furnace

September 2023

Cleveland-Cliffs Steel, LLC
Indiana Harbor East

CLIFFS
CLEVELAND-CLIFFS INC.

Mr. David Cline
Indiana Department of Environmental Management
Office of Air Quality, Compliance, M/C 61-50
100 North Senate Avenue
Indianapolis, Indiana 46206

November 17, 2023

Subject: **Cleveland-Cliffs Steel LLC. – Indiana Harbor East**
Submittal of Compliance Test Results
80" Hot Strip No. 5 and No. 6 Walking Beam Furnaces
Part 70 Permit No.: T089-38315-00316 (Issued 01/18/19)
Last revised as: 089-44076-00316 (Issued 12/01/21)

Dear Mr. Cline:

As required by 326 IAC 2-7-6(1), this letter submits the results of the SIP NO_X compliance testing for the No. 5 & 6 Walking Beam Furnaces (WBF) at the 80" Hot Strip Mill. Compliance testing was conducted on September 21 and 22nd, 2023.

Facility: Control Device	Parameter	Title V Permit Condition	Limit (lb/MMscf Nat. gas)	Actual (lb/MMscf Nat. gas)
No. 5 Walking Beam Furnace	NO_X	D.9.2(a)	357	290
No. 6 Walking Beam Furnace	NO_X	D.9.2(a)	357	289

Test results for the Walking Beam Furnaces show compliance with the SIP NO_X limitation identified in the facilities Title V under condition D.9.2(a).

Test Method 7E, as used to perform this test, conforms to the requirements of Indiana rule 326 IAC 3-6-5.

If you have any questions, please call Mr. Brian Wolters of my staff at (219) 399-2330.

Sincerely,

Tom Barnett
Manager, Environmental
Indiana Harbor East

Attachments
Gaseous Emissions Test Report – November 17, 2023

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY

PART 70 OPERATING PERMIT CERTIFICATION

Source Name:	Cleveland-Cliffs Steel LLC - Indiana Harbor East
Source Address:	3210 Watling Street, East Chicago, Indiana 46312
Mailing Address:	3210 Watling Street MC 8-130, East Chicago, Indiana 46312
Part 70 Permit No.:	T089-38315-00316 (Issued 01/18/19)
Last revised as:	089-44076-00316 (Issued 12/01/21)

This certification shall be included when submitting monitoring, testing reports/results or other documents as required by this permit.

Please check what document is being certified:

☐ Annual Compliance Certification

☒ Test Result: **80" Hot Strip Mill Walking Beam Furnaces #5, and #6 Nitrogen Oxides (NO_X) Compliance Demonstration Test**

☐ Report: (specify)

☐ Notification (specify)

☐ Affidavit (specify)

☐ Other (specify)

I certify that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

Signature:	LaDale Combs
Printed Name:	LaDale Combs
Title/Position:	Senior General Manager, Indiana Harbor
Phone:	(219) 399-7000
Date:	11-17-2023

SOURCE EMISSIONS TEST DATA
80' Hot Strip Mill-No. 5 Walking Beam Furnace
80' Hot Strip Mill-No. 6 Walking Beam Furnace
East Chicago, IN

September 21-22, 2023

Prepared for:

Cleveland-Cliffs Steel LLC
East Chicago, IN
Permit: 089-29993-00316

Prepared by:

Environmental Quality Management, Inc.
1280 Arrowhead Court
Suite 2
Crown Point, IN 46307
(219) 661-9900
www.eqm.com

PN: 050809.0008

November 2023

PREFACE

I, Karl Mast, do hereby certify that the source emissions testing conducted at Cleveland-Cliffs in East Chicago, IN was performed in accordance with the test protocol that was prepared August 4-5 and submitted to the U.S. EPA and IDEM and that the data and results submitted within this report are an exact representation of the testing.

Karl Mast
Test Supervisor

I, Karl Mast, do hereby attest that all work on this project was performed under my direct supervision, and that this report accurately and authentically presents the source emissions testing conducted at Cleveland-Cliffs in East Chicago, IN.

Karl Mast
Test Supervisor

SUMMARY

The emission testing program was performed at the 80’ Hot Strip Mill’s No. 5 and No. 6 Walking Beam Furnaces. The testing was performed in accordance with USEPA Methods 1, 2, 3A, 4, 6A, 7E and 19. The results of the source testing are detailed in the following tables. Field data collected during the testing may be found in Appendix A. Additional Rolling Average data may be found in Appendix G.

No. 5 Walking Beam Furnace-lb/mmscf- Natural Gas Test Results				
Run 1	**Run 2**	**Run 3**	**Average**	**Limit**
332	262	274	290	357

No. 6 Walking Beam Furnace -lb/mmscf-Natural Gas Test Results				
Run 1	**Run 2**	**Run 3**	**Average**	**Limit**
297	283	288	289	357

Table 5. Measured & Calculated Data, Emission Test Results
No. 5 Walking Beam Furnace

Summary of Stack Gas Parameters and Test Results
80" #5
East Chicago
US EPA Test Method 2- Velocity
Outlet
Page 1 of 1

	RUN NUMBER	O-1	O-2	O-3	
	RUN DATE	9/22/2023	9/22/2023	9/22/2023	Average
	RUN TIME	828-927	1105-1204	1610-1709	
	MEASURED DATA				
P_{static}	Stack Static Pressure, inches H_2O	0.10	0.11	0.13	0.11
P_{bar}	Barometric Pressure, inches Hg	29.51	29.49	29.50	29.50
$Dp^{1/2}$	Average Square Root Dp, (in. H_2O)$^{1/2}$	0.6105	0.5324	0.5316	0.5582
T_s	Average Stack Temperature, °F	768	775	788	777
CO_2	Carbon Dioxide content, % by volume	6.9	7.3	8.2	7.5
O_2	Oxygen content, % by volume	8.2	7.5	5.9	7.2
N_2	Nitrogen content, % by volume	84.9	85.2	85.9	85.3
C_p	Pitot Tube Coefficient	0.84	0.84	0.84	0.84
	Circular Stack? 1=Y,0=N:	1	1	1	1
As	Diameter or Dimensions, inches:	141.00	141.00	141.00	141.00
	CALCULATED DATA				
P_s	Stack Pressure, inches Hg	29.51	29.49	29.51	29.50
B_{ws}	Moisture, % by volume	12.1	12.3	11.3	11.9
$B_{ws(sat)}$	Moisture (at saturation), % by volume	32280.2	33521.5	35884.2	`
$1\text{-}B_{ws}$	Dry Mole Fraction	0.879	0.877	0.887	0.881
M_d	Molecular Weight (d.b.), lb/lb•mole	29.43	29.47	29.55	29.48
M_s	Molecular Weight (w.b.), lb/lb•mole	28.05	28.06	28.24	28.12
V_s	Stack Gas Velocity, ft/s	53.4	46.7	46.7	48.9
A	Stack Area, ft^2	108.434	108.434	108.434	108.43
Q_a	Stack Gas Volumetric flow, acfm	347,450	303,853	304,038	318,447
Q_s	Stack Gas Volumetric flow, dscfm	129,427.61	112,241.61	112,391.56	118,020
Q_s	Stack Gas Volumetric flow, dscmm	3,665	3,178	3,183	3,342
	Oxygen				
O_2	**Concentration PPM Dry**	**8.2**	**7.5**	**5.9**	**7.18**
	Nitrogen Oxides				
NO_x	**Concentration PPM Dry**	**181.96**	**151.34**	**176.98**	**170.09**
NO_x	**Concentration PPM Dry @ 15% O_2**	**84.27**	**66.63**	**69.47**	**73.46**
E NO_x	**Emission Rate, lb/hr**	**168.67**	**121.66**	**142.46**	**144.27**
E NO_x	**Emission Rate, lb/mmbtu**	**0.310**	**0.245**	**0.256**	**0.271**
E NO_x	**Emission Rate, lb/mmscf**	**332.17**	**262.66**	**273.85**	**289.56**

Table 6. Measured & Calculated Data, Emission Test Results
No. 6 Walking Beam Furnace

	Summary of Stack Gas Parameters and Test Results				
	80" #6				
	East Chicago				
	US EPA Test Method 2- Velocity				
	Outlet				
	Page 1 of 1				
	RUN NUMBER	***O-1***	***O-2***	***O-3***	
	RUN DATE	***9/21/2023***	***9/21/2023***	***9/21/2023***	***Average***
	RUN TIME	***800-859***	***1130-1229***	***245-344***	
	MEASURED DATA				
P_{static}	Stack Static Pressure, inches H_2O	0.17	0.17	0.18	0.17
P_{bar}	Barometric Pressure, inches Hg	29.56	29.56	29.56	29.56
$Dp^{1/2}$	Average Square Root Dp, (in. $H_2O)^{1/2}$	0.4974	0.5335	0.6741	0.5684
T_s	Average Stack Temperature, °F	812	795	939	849
CO_2	Carbon Dioxide content, % by volume	8.4	8.7	8.8	8.6
O_2	Oxygen content, % by volume	5.8	5.3	5.0	5.4
N_2	Nitrogen content, % by volume	85.8	86.0	86.3	86.0
C_p	Pitot Tube Coefficient	0.84	0.84	0.84	0.84
	Circular Stack? 1=Y,0=N:	1	1	1	1.0000
As	Diameter or Dimensions, inches:	141.00	141.00	141.00	141.00
	CALCULATED DATA				
P_s	Stack Pressure, inches Hg	29.57	29.57	29.57	29.57
B_{ws}	Moisture, % by volume	13.4	11.4	13.0	12.6
$B_{ws(sat)}$	Moisture (at saturation), % by volume	40354.5	37123.9	71642.7	49707.0
$1-B_{ws}$	Dry Mole Fraction	0.866	0.886	0.870	0.874
M_d	Molecular Weight (d.b.), lb/lb•mole	29.57	29.60	29.60	29.59
M_s	Molecular Weight (w.b.), lb/lb•mole	28.02	28.28	28.09	28.13
V_s	Stack Gas Velocity, ft/s	44.3	46.9	62.8	51.3
A	Stack Area, ft^2	108.434	108.434	108.434	108.43
Q_a	Stack Gas Volumetric flow, acfm	287,922	305,382	408,629	333,978
Q_s	Stack Gas Volumetric flow, dscfm	102,266.73	112,460.92	132,641.24	115,790
Q_s	Stack Gas Volumetric flow, dscmm	2,896	3,185	3,756	3,279
	Oxygen				
O_2	**Concentration PPM Dry**	**5.8**	**5.3**	**5.0**	**5.38**
	Nitrogen Oxides				
NO_x	**Concentration PPM Dry**	**193.89**	**191.28**	**198.46**	**194.54**
NO_x	**Concentration PPM Dry @ 15% O_2**	**75.96**	**72.34**	**73.60**	**73.97**
E NO_x	**Emission Rate, lb/hr**	**142.02**	**154.07**	**188.54**	**161.54**
E NOx	**Emission Rate, lb/mmbtu**	**0.280**	**0.267**	**0.271**	**0.272**
E NOx	**Emission Rate, lb/mmscf**	**297.18**	**283.03**	**287.94**	**289.38**

No. 4 - Walking Beam Furnace

November 2023

SOURCE EMISSIONS TEST DATA
80" Hot Strip Mill-No. 4 Walking Beam Furnace
East Chicago, IN

November 2, 2023

Prepared for:

Cleveland-Cliffs Steel LLC
East Chicago, IN
Permit: 089-29993-00316

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December 2023

PREFACE

I, Karl Mast, do hereby certify that the source emissions testing conducted at Cleveland-Cliffs in East Chicago, IN was performed in accordance with the test protocol that was prepared August 4-5 and submitted to the U.S. EPA and IDEM and that the data and results submitted within this report are an exact representation of the testing.

Karl Mast
Test Supervisor

I, Karl Mast, do hereby attest that all work on this project was performed under my direct supervision, and that this report accurately and authentically presents the source emissions testing conducted at Cleveland-Cliffs in East Chicago, IN.

Karl Mast
Test Supervisor

SUMMARY

The emission testing program was performed at the 80" Hot Strip Mill's No. 4 Walking Beam Furnaces. The testing was performed in accordance with USEPA Methods 1, 2, 3A, 4, 6A, 7E and 19. The results of the source testing are detailed in the following tables. Field data collected during the testing may be found in Appendix A.

No. 4 Walking Beam Furnace-lb/mmscf- NO_x Test Results					
Parameter	**Run 1**	**Run 2**	**Run 3**	**Average**	**Limit**
North	127.21	124.56	113.09	121.62	357
South	155.43	171.49	144.15	157.02	357
Total	141.32	148.02	128.62	139.32	357

Table 2. Measured & Calculated Data, Emission Test Results
No. 4 North Walking Beam Furnace

	Summary of Stack Gas Parameters and Test Results				
	No. 4 North Walking Beam Furance				
	East Chicago				
	US EPA Test Method 2- Velocity				
	Outlet				
	Page 1 of 1				
	RUN NUMBER	***O-1***	***O-2***	***O-3***	
	RUN DATE	***11/2/2023***	***11/2/2023***	***11/2/2023***	***Average***
	RUN TIME	***1026-1125***	***1130-1229***	***1234-1333***	
	MEASURED DATA				
P_{static}	Stack Static Pressure, inches H_2O	-1.74	-1.85	-1.79	-1.79
P_{bar}	Barometric Pressure, inches Hg	29.60	29.60	29.60	29.60
$Dp^{1/2}$	Average Square Root Dp, (in. $H_2O)^{1/2}$	1.1296	1.4757	1.2575	1.2876
T_s	Average Stack Temperature, °F	528	541	531	534
CO_2	Carbon Dioxide content, % by volume	5.4	5.1	5.4	5.3
O_2	Oxygen content, % by volume	10.9	11.4	10.8	11.0
N_2	Nitrogen content, % by volume	83.7	83.5	83.8	83.6
C_p	Pitot Tube Coefficient	0.84	0.84	0.84	0.84
	Circular Stack? 1=Y,0=N:	1	1	1	1.0000
As	Diameter or Dimensions, inches:	120.00	120.00	120.00	120.00
	CALCULATED DATA				
P_s	Stack Pressure, inches Hg	29.48	29.47	29.47	29.47
B_{ws}	Moisture, % by volume	4.7	5.2	4.5	4.8
$B_{ws(sat)}$	Moisture (at saturation), % by volume	6318.5	7065.2	6497.1	`
$1-B_{ws}$	Dry Mole Fraction	0.953	0.948	0.955	0.952
M_d	Molecular Weight (d.b.), lb/lb•mole	29.30	29.28	29.30	29.29
M_s	Molecular Weight (w.b.), lb/lb•mole	28.76	28.69	28.79	28.75
V_s	Stack Gas Velocity, ft/s	87.6	115.3	97.6	100.2
A	Stack Area, ft^2	78.540	78.540	78.540	78.54
Q_a	Stack Gas Volumetric flow, acfm	412,715	543,481	459,966	472,054
Q_s	Stack Gas Volumetric flow, dscfm	206,871.50	267,451.36	230,378.15	234,900
Q_s	Stack Gas Volumetric flow, dscmm	5,858	7,573	6,524	6,652
	Oxygen				
O_2	**Concentration PPM Dry**	**10.9**	**11.4**	**10.8**	**11.05**
	Nitrogen Oxides				
NO_x	**Concentration PPM Dry**	**59.24**	**55.35**	**53.35**	**55.98**
NO_x	**Concentration PPM Dry @ 15% O_2**	**35.09**	**34.36**	**31.20**	**33.55**
E NO_x	**Emission Rate, lb/hr**	**87.77**	**106.03**	**88.03**	**93.94**
E NO_x	**Emission Rate, lb/mmbtu**	**0.129**	**0.127**	**0.115**	**0.124**
E NO_x	**Emission Rate, lb/mmscf**	**127.21**	**124.56**	**113.09**	**121.62**

Table 3. Measured & Calculated Data, Emission Test Results
No. 4 South Walking Beam Furnace

	Summary of Stack Gas Parameters and Test Results				
	No. 4 South Walking Beam Furance				
	East Chicago				
	US EPA Test Method 2- Velocity				
	Outlet				
	Page 1 of 1				
	RUN NUMBER	***O-1***	***O-2***	***O-3***	
	RUN DATE	***11/2/2023***	***11/2/2023***	***11/2/2023***	***Average***
	RUN TIME	***1026-1125***	***1130-1229***	***1234-1333***	
	MEASURED DATA				
P_{static}	Stack Static Pressure, inches H_2O	-1.31	-1.45	-1.38	-1.38
P_{bar}	Barometric Pressure, inches Hg	29.60	29.60	29.60	29.60
$Dp^{1/2}$	Average Square Root Dp, (in. $H_2O)^{1/2}$	1.0377	1.2047	1.0729	1.1051
T_s	Average Stack Temperature, °F	533	541	554	543
CO_2	Carbon Dioxide content, % by volume	6.7	6.3	7.0	6.7
O_2	Oxygen content, % by volume	10.3	10.9	9.8	10.3
N_2	Nitrogen content, % by volume	83.0	82.8	83.2	83.0
C_p	Pitot Tube Coefficient	0.84	0.84	0.84	0.84
	Circular Stack? 1=Y,0=N:	1	1	1	1.0000
As	Diameter or Dimensions, inches:	120.00	120.00	120.00	120.00
	CALCULATED DATA				
P_s	Stack Pressure, inches Hg	29.51	29.50	29.50	29.50
B_{ws}	Moisture, % by volume	4.6	5.2	5.1	5.0
$B_{ws(sat)}$	Moisture (at saturation), % by volume	6565.6	7026.2	7844.4	`
$1-B_{ws}$	Dry Mole Fraction	0.954	0.948	0.949	0.950
M_d	Molecular Weight (d.b.), lb/lb•mole	29.48	29.44	29.51	29.48
M_s	Molecular Weight (w.b.), lb/lb•mole	28.96	28.84	28.92	28.91
V_s	Stack Gas Velocity, ft/s	80.3	93.8	84.0	86.1
A	Stack Area, ft^2	78.540	78.540	78.540	78.54
Q_a	Stack Gas Volumetric flow, acfm	378,523	442,151	395,858	405,511
Q_s	Stack Gas Volumetric flow, dscfm	189,389.11	217,806.11	192,780.90	199,992
Q_s	Stack Gas Volumetric flow, dscmm	5,363	6,168	5,459	5,663
	Oxygen				
O_2	**Concentration PPM Dry**	**10.3**	**10.9**	**9.8**	**10.34**
	Nitrogen Oxides				
NO_x	**Concentration PPM Dry**	**77.25**	**80.02**	**74.61**	**77.29**
NO_x	**Concentration PPM Dry @ 15% O_2**	**42.88**	**47.31**	**39.77**	**43.32**
E NO_x	**Emission Rate, lb/hr**	**104.79**	**124.83**	**103.02**	**110.88**
E NO_x	**Emission Rate, lb/mmbtu**	**0.158**	**0.174**	**0.146**	**0.160**
E NO_x	**Emission Rate, lb/mmscf**	**155.43**	**171.49**	**144.15**	**157.02**

Table 4. Calculated Data, Total Emission Test Results
No. 4 Walking Beam Furnace

No. 4 North Walking Beam Furnace					
	Oxygen	Run 1	Run 2	Run 3	AVERAGE
O_2	**Concentration PPM Dry**	**10.9**	**11.4**	**10.8**	**11.05**
	Nitrogen Oxides				
NO_x	**Concentration PPM Dry**	**59.24**	**55.35**	**53.35**	**55.98**
NO_x	**Concentration PPM Dry @ 15% O_2**	**35.09**	**34.36**	**31.20**	**33.55**
E NO_x	**Emission Rate, lb/hr**	**87.77**	**106.03**	**88.03**	**93.94**
E NO_x	**Emission Rate, lb/mmbtu**	**0.129**	**0.127**	**0.115**	**0.124**
E NO_x	**Emission Rate, lb/mmscf**	**127.21**	**124.56**	**113.09**	**121.62**
No 4 South Walking Beam Furance					
	Oxygen				AVERAGE
O_2	**Concentration PPM Dry**	**10.3**	**10.9**	**9.8**	**10.34**
	Nitrogen Oxides				
NO_x	**Concentration PPM Dry**	**77.25**	**80.02**	**74.61**	**77.29**
NO_x	**Concentration PPM Dry @ 15% O_2**	**42.88**	**47.31**	**39.77**	**43.32**
E NO_x	**Emission Rate, lb/hr**	**104.79**	**124.83**	**103.02**	**110.88**
E NO_x	**Emission Rate, lb/mmbtu**	**0.158**	**0.174**	**0.146**	**0.160**
E NO_x	**Emission Rate, lb/mmscf**	**155.43**	**171.49**	**144.15**	**157.02**
Calculated Total Emission Rates					
					TOTAL
E NO_x	**Emission Rate, lb/hr**	**192.56**	**230.86**	**191.05**	**204.82**
E NO_x	**Emission Rate, lb/mmbtu**	**0.144**	**0.150**	**0.131**	**0.14**
E NO_x	**Emission Rate, lb/mmscf**	**141.32**	**148.02**	**128.62**	**139.32**

APPENDIX D. 2023 AECOM BOILER STUDY

Cleveland Cliffs Steel, Inc.

Boiler NO_x Reduction Evaluation

ArcelorMittal

Project number: 60712282

August 29, 2023

DRAFT

Delivering a better world

Quality information

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Executive Summary

Cleveland Cliffs Steel (CCS) has three boilers that will be subject to the Cross-State Air Pollution Rule (CSAPR), which requires reductions in NOx emissions from all three boilers to a level of 0.08 lb/MMBtu on a 30-day rolling average. The compliance date is May 1, 2026; therefore, CCS has about 33 months to install controls and verify compliance with the rule.

AECOM has reviewed the potential effectiveness of a variety of combustion and post-combustion NO_x control strategies, and budgetary estimates have been produced that include capital costs and cost effectiveness for the application of NO_x controls to all three units. One finding from the study is that there is a range in the potential effectiveness of all of the technologies that were evaluated. It is possible that one or more combustion modification techniques could achieve compliance. Similarly, it is possible low-NO_x burners (LNBs) alone could achieve compliance. However, post-combustion technologies such as selective noncatalytic reduction (SNCR) and selective catalytic reduction (SCR) do not appear applicable or cost-effective for the CCS boilers.

AECOM recommends a strategy whereby an investigation is initiated to gather the data needed to develop the most cost-effective compliance approach. This investigation should include the following elements:

- Installation of a flue gas recirculation duct on Unit 7 to evaluate the effectiveness of both induced flue gas recirculation (IFGR) and then flue gas recirculation (FGR);
- Installation of an over-fire air (OFA) duct on Unit 8, using existing boiler penetrations from burners that have been removed from the boiler; and
- Initiation of a study by one or more burner vendors to quantify low-NO_x burner performance and cost for all three boilers.

Costs for the above are approximately $2.6 million, plus the cost of any testing to evaluate performance, and the cost for any burner vendor studies. The objective of this initial effort is to gather the information needed for determining the most cost-effective next steps. If the initial steps (FGR on Unit 7 and OFA on Unit 8) do not result in compliance, these steps could include the application of additional combustion modification technologies and/or the installation of low-NO_x burners. The investigation outlined above should be initiated as quickly as possible.

1. Introduction

The Environmental Protection Agency (EPA) recently promulgated requirements for small boilers under the Cross-State Air Pollution Rule (CSAPR) to reduce oxides of nitrogen (NO_x) emissions during the ozone season (May 1 through September 30). The NO_x emission requirement is dependent on the type of fuel being burned in the affected boilers. Cleveland Cliffs Steel (CCS) operates three boilers, each of which burns only natural gas. According to the new rule, CCS must achieve NO_x emissions levels of 0.08 pounds per million British Thermal Units (lb/MMBtu) based on a 30-day rolling average from each of the three boilers. The affected units will be required to install and operate Continuous Emissions Monitoring Systems (CEMS) to measure and report the NO_x emissions.

The purpose of this study is to identify technologies that will allow CCS to achieve the required emission levels and to provide budgetary estimates of the costs to implement these technologies. The remainder of this report documents the results of the study and is organized as follows:

- Section 2 summarizes the operating characteristics of the CCS boilers and includes the results of NO_x emissions measurements made by plant personnel;
- Section 3 presents an overview of NO_x reduction technologies including both combustion and post-combustion approaches. This section also provides information on the applicability of the various technologies to the CCS boilers;
- Section 4 summarizes the costs of each technology. Separate estimates are provided for Unit 8 and Units 6 & 7, and the results include both installed capital costs and annualized costs. Costs are also provided for CEMS; and,
- Section 5 summarizes the conclusions of the study and provides recommendations for a path forward for CCS.

References used in the study are listed in Appendix A.

2. Existing Equipment and Performance

The Cleveland Cliffs Steel (CCS) plant operates three steam generating units at their facility. These units are identified as Units 6, 7 and 8. A fourth unit is located on this site, Unit 9, but it is not under the direct control of CCS and is not considered in this study. Units 6, 7 and 8 produce superheated steam, some of which is used to drive a turbine-generator for electricity production. All three units have been de-rated due to tube failures and other issues affecting boiler capacity.

Units 6 and 7 are wall fired boilers manufactured by Babcock & Wilcox, both having 6 burners that are arranged with three elevations of 2 burners. Unit 8 was manufactured by Combustion Engineering and is tangentially fired with 2 elevations of burners in each of the 4 corners of the furnace. All three units were originally designed to burn coal, oil, blast furnace gas or natural gas. The coal and oil burners have been removed and their original locations covered with steel plate. Currently, all three units burn only natural gas. The design and present operating conditions for each unit are shown in Table 2-1.

Table 2-1. Operating Characteristics of Units 6, 7 & 8

Unit	Year Built	Design Characteristics				Present Operating Conditions (August 2023)		
		Heat Input, MMBtu/hr	Steam Flow, K lb/hr	Steam Temp., °F	Steam Press., psig	Heat Input, MMBtu/hr	Steam Flow, K lb/Hr	Flue Gas Oxygen, vol % wet
6	1955	454	330*	760	800	329	215	4.9
7	1955	454	330*	760	800	356	257	5.0
8	1966	1,090	790*	812	819	612	429	4.3

Notes: * = Calculated value based on Heat Input and estimated boiler efficiency of 83.5%.

The data in Table 2-1 show that at present operating conditions, the units are operating at loads of 72%, 78% and 56% of full load capacity for units 6, 7 and 8, respectively. Notable other issues are that all fans, both forced draft (FD) and induced draft (ID), are steam turbine driven and have no flow control dampers. Combustion air flow to the boiler windboxes is regulated solely by regulating the steam flow to the turbines driving the fans. Because of their age, all three units are prone to frequent tube failures. When a tube failure occurs, the failed tube is often plugged which further reduces operating capacity.

Plant personnel made preliminary NO_x measurements at several locations on each unit to establish baseline NO_x levels. While the appropriate sampling location for emissions measurements is the stack, only Unit 7 has a test penetration in the stack that allows for extraction of flue gas samples for analysis. Samples from Units 6 and 8 were instead collected from various locations including the furnace and ducts before and after the air heater. Samples collected from the furnace and ducts before the ID fan can be poorly mixed and not representative of the actual concentrations of the flue gas constituents.

Measurements of the NO_x concentrations were made using a hand-held portable analyzer. Some of the data collected by the plant personnel is summarized in Table 2-2. The conversion of NO_x in parts per million (ppm) to pounds per million Btu (lb/MMBtu) was done using the measured O_2 concentration and the EPA Method 19 "F"-factor calculation. The extracted samples contained a considerable amount of moisture, and some of this condensed in the sampling tubing and was then collected in a condensate trap at the inlet of the hand-held analyzer. As part of the calculation, it was assumed that the flue gas analyzer was at a temperature of approximately 95°F, at which temperature the moisture content was approximately 5.5% by volume. Therefore, the NO_x and oxygen values measured by the analyzer were assumed to contain 5.5% moisture and were converted to a dry basis before being converted to lb/MMBtu using the dry "F"-factor calculation method. The "F"-factor used in the calculation was that published in EPA Method 19 (8,710 dscf/MMBtu).

Table 2-2. Baseline NO_x Measurements made on Units 6, 7 & 8

Unit		6	6	7	7	8	8
Sample Location		Heat Exchanger Upper Level	Heat Exchanger Lower Level	Stack	Heat Exchanger	Top of Heat Exchanger, North	Top of Heat Exchanger, South
Estimated Instrument Temperature	°F	95	95	95	95	95	95
Sample Gas Moisture	Vol % wet	5.5	5.5	5.5	5.5	5.5	5.5
NO_x, As Measured	ppmv wet	94	89	40	52	109	106
O_2, As Measured	Vol % wet	5.3	7.0	13.5	11.9	6.6	7.7
NO_x Dry Basis	ppmv dry	99.5	94.2	42.3	55.0	115.3	112.2
O_2 Dry Basis	Vol % dry	5.6	7.4	14.3	12.6	7.0	8.1
NO_x: ppm to lb/scf	Conversion Factor	1.194E-07	1.194E-07	1.194E-07	1.194E-07	1.194E-07	1.194E-07
C_d	lb/dscf	1.188E-05	1.125E-05	5.054E-06	6.570E-06	1.377E-05	1.339E-05
F_d	dscf/MMBtu	8,710	8,710	8,710	8,710	8,710	8,710
Emission Rate	lb/MMBtu	0.141	0.152	0.139	0.144	0.180	0.191

These measurements show that baseline NO_x emissions are between 0.14 lb/MMBtu and 0.19 lb/MMBtu. Although the actual operating conditions of the units at the time of the measurements were not stated, it is likely that the operating load was at or below the de-rate load and full load NO_x emissions could be higher, or lower, than those measured. Plant personnel indicated that future possible life extension programs might include refurbishing one or more of the boilers. Therefore, for the purpose of this study, a conservative baseline NO_x level of 0.20 lb/MMBtu has been used. Therefore, to achieve the required 0.08 lb/MMBtu level required for the CSAPR rule, a 60% reduction in NO_x will be required.

3. NOx Reduction Technologies

There are several technologies available for reducing NO_x. These basically fall into two categories: combustion modifications or front-end NO_x reduction (retardation of the formation of NO_x) and post combustion reduction (removal of NO_x from the flue gas stream). To fully appreciate these technologies, a fundamental understanding of NO_x formation is useful.

3.1 NO_x Formation

NO_x is formed when free nitrogen atoms combine with free oxygen atoms in combustion gases to form the molecule NO. This occurs in three manners: fuel NO_x, thermal NO_x, and prompt NO_x. Fuel NO_x is formed when nitrogen in the fuel, mostly solid and liquid fuels but can occur in some gaseous fuels, in the mono-atomic form, breaks free from the fuel molecules and the resulting N atoms combine with free oxygen atoms to form NO. Thermal NO_x is formed by the fixation of molecular nitrogen (from air) and oxygen from air. The nitrogen molecule in air is diatomic and requires higher energy levels to dissociate than does the single bonded fuel nitrogen. Therefore, fixation of molecular nitrogen in air occurs at temperatures greater than 3,600°F. Although the quantity of nitrogen in liquid and solid fuels (oil and coal) is relatively low and the quantity of nitrogen in air is high (air comprises 78.1% nitrogen), formation of NO_x in the combustion of liquid and solid fuels is dominated by fuel nitrogen because of the high temperature required to dissociate the air nitrogen. Prompt NO_x forms from the oxidation of hydrocarbon radicals near the combustion flame and produces an insignificant amount of NO_x.

The combustion sources at CCS burn only natural gas, which contains an insignificant amount of fuel nitrogen. Therefore, essentially all of the NO_x formed is from fixation of air nitrogen. Therefore, if the peak flame temperature of combustion is reduced, fewer diatomic nitrogen molecules in air are dissociated and there are fewer free nitrogen atoms available to combine with oxygen to form the NO molecule. In addition, if there is a deficiency of oxygen available to combine with the nitrogen atoms, the free nitrogen atoms often combine with other free nitrogen atoms, reverting to diatomic bond nitrogen molecules (as is the nitrogen in air).

3.2 Combustion Modification Technologies

As previously mentioned, one approach to reducing NO_x emissions is to reduce the formation of NO_x by either reducing the combustion peak flame temperature or by reducing the quantity of oxygen available for reaction with free nitrogen atoms in the combustion zone. The following section discusses several technologies that can reduce NO_x by these two approaches. The discussion includes the approximate NO_x reduction that could be achieved by each, and any technical issues associated with implementing them. In the discussion of each technology, the NO_x reduction is expressed as a range between expected minimum and maximum values. The NO_x reduction for each technology was found in several Environmental Protection Agency (EPA) documents which cover the results of numerous test programs on a variety of different boilers.

The specific NO_x reduction of any given technology is a function of a number of variables. These include existing burner design and arrangement. The combustion characteristics and NO_x emissions can be different for the wall-fired boilers (Units 6 and 7) versus the tangential-fired boiler (Unit 8). Also, furnace heat release volume and extended furnace heat transfer surface affects peak flame temperature and, therefore, NO_x formation. Units 6 and 7 were originally designed as stoker units while Unit 8 was originally designed for pulverized coal. Thus, all three units have furnace volumes and extended furnace heat transfer surfaces larger than units originally designed for natural gas combustion. The specific expected NO_x reduction of any of the technologies discussed can only be determined by more detailed engineering studies. In some cases, the best manner to determine the effectiveness of a particular technology (especially those that are relatively low cost) would be to install that technology on one of the units and test it.

Combustion Tuning

Combustion tuning is an exercise whereby the fuel flow and air flow to each burner is balanced and the quantity of excess air is minimized. For large multi-burner boilers burning solid fuel (coal) this can require flue gas sampling at the air heater inlet through multiple test ports. However, with boilers burning liquid and gaseous fuels, where the fuel flows are reasonably well metered and are uniform to each burner, sampling from one test port in the stack is satisfactory. Balancing the fuel and air flow to each burner allows for uniform combustion and reduction of excess air to a minimum level. A minimum excess air level would be that level where carbon monoxide formation starts to occur and is typically at flue gas oxygen levels of 2% to 3% depending on the boiler load. By minimizing the oxygen in the flue gas, the turbulence in the combustion zone is reduced, which reduces peak flame temperature and, therefore, reduces NO_x formation. In addition, lower oxygen availability in the combustion zone reduces the amount of oxygen available for oxidation of free nitrogen atoms, which also reduces NO_x. Reduction of NO_x emissions by reduction of excess air can be in the range of 5% to 35%.

The cost of combustion tuning is relatively low and would be in the range of $50,000 for all three boilers if all three units had combustion tuning conducted during the same deployment. An advantage of combustion tuning is a corresponding increase in boiler efficiency with operation of the combustion process at a lower excess air level. Lowering the excess air for combustion customarily results in lower flue gas temperature and lower quantity of flue gas exiting the stack. These two effects results in a lower Dry Flue Gas energy loss and a corresponding increase in boiler efficiency.

There are several reasons that that the effectiveness of combustion tuning would be limited at the CCS facility. First and foremost is the fact that there are no state-of-the-art flow controls on the combustion air supply. Combustion air flow and flue gas flow by the forced draft (FD) and induced draft (ID) fans, respectively, are controlled by the steam turbines that drive the fans. There are no air and flue gas flow control dampers. The ability to modulate the fan steam turbine drive is very limited and does not provide sufficient control to enable fine tuning of the combustion process. Although natural gas flow to each burner can be biased by use of control valves in the natural gas feed, control of air flow to each burner is achieved by antiquated dampers which are difficult to control and do not afford accurate modulation. Therefore, although combustion tuning is a cost effective and technically feasible NO_x reduction technology, updated air flow controls will be necessary to achieve meaningful NO_x reductions.

Staged Combustion

Staged combustion is the operation of the combustion process incorporating Over-Fire Air (OFA). This can be implemented in two ways: operation of the unit with top elevation of burners out of service with continued air flow through the out-of-service burners, or installation of Over-Fire Air ports (OFAp). Operation of the combustion process with OFA results in the primary combustion zone operating with a deficiency of combustion air – in the range of 90% of stoichiometric air. The balance of air for combustion enters the furnace through the out of service burners or the OFAp. Operation of the combustion process in a staged combustion fashion results in reduced peak flame temperatures and deficiency of oxygen in the furnace and, therefore, reduced formation of NO_x. Operation with staged combustion can result in NO_x reduction efficiencies of 15% to 50%. Operation with OFA does not significantly affect boiler performance or efficiency.

Units 6 and 7 have 3 elevations of wall fired burners and lends themselves to operation with burners out of service. However, this would necessitate operation at a reduced capacity of 66% of full load or less. The alternative to operation with burners out of service would be installation of OFAp which would necessitate installing penetrations in the water walls above the top row of burners. This would require removal of some water-wall tubing and subsequent alteration of pressure parts.

Operation of Unit 8 with burners out of service would not be viable, as there are only two rows of burners. However, Unit 8 was initially designed for pulverized coal and the original pulverized coal burners, which were removed and covered with plate, were above the existing natural gas burners. Therefore, installation of OFA would not be difficult and would likely not require removal of boiler tubes.

Flue Gas Recirculation

Flue gas recirculation (FGR) involves moving flue gas from the exhaust of the ID fan to the inlet of the FD fan. The flue gas, which is low in oxygen content, acts as a relatively low oxygen and low temperature inert medium which quenches the peak flame temperature, thus reducing fixation of air nitrogen resulting in lower NO_x. FGR has been shown to be quite effective in lowering NO_x, with NO_x reductions of 30% to 60%. Some boilers burning natural gas have shown NO_x reductions 50% to 60% with FGR rates as low as 20% to 25%.

FGR can be accomplished by two means: “induced” FGR and forced FGR. Induced FGR is done by connecting a duct from the exhaust of the ID fan to the inlet of the FD fan and using the pressure differential between those two points to move flue gas. This arrangement can be used for low FGR rates. Forced FGR would be done by installing a fan in the duct between the ID fan exhaust and FD fan inlet to move higher rates of flue gas – rates up to 50%, although FGR rates are more typically in the range of 20% to 30%. Because the flue gas is lower in oxygen content than air, the objective of FGR is to lower the oxygen content of the combustion air. The lower the oxygen in the combustion air the greater the reduction in NO_x will be. Oxygen levels in the windbox as low as 18% have been targeted.

Issues regarding retrofit of FGR on the CCS units include that the existing burners might not be sufficiently stable for FGR rates required to achieve the required NO_x reduction on the order of about 50%. Therefore, installation of Low NO_x Burners (LNB) which are designed for stable operation when FGR is used, might be necessary. For control purposes, a flow control damper would need to be installed in the FGR duct, and it would be advisable to install an oxygen analyzer in the windbox to monitor the oxygen of the combustion air/recycled flue gas entering the burners.

Reduction of Combustion Air Temperature

Reduction of the combustion air temperature has been demonstrated to be an effective technique for reducing NO_x emissions. The combustion air temperature reduction can be accomplished by either slowing the rotational speed of the air heater, removing heat transfer surface from air heater, or by bypassing the air heater entirely. By lowering the air temperature for combustion, the peak flame temperature is lowered, thus lowering formation of NO_x. Lowering the combustion air temperature into the windbox to 130^oF, for example, has been shown to reduce NO_x emissions by 20% and 50%.

The negative side of reducing the combustion air temperature is the resultant increase in flue gas temperature entering the ID fan and exiting the stack with a resultant potentially significant loss in boiler efficiency. The loss in boiler efficiency can be counteracted, to some degree, by adding a heat recovery device. However, such heat recovery would not be to pre-heat the combustion air but would need to be used somewhere else in the plant (i.e., heat water or provide process steam). It is believed that Units 6, 7 and 8 already have economizers, so the heat recovered from the flue gas would need to be used somewhere else in the plant. If there is no heat recovery of the higher-temperature flue gas, the reduction in boiler efficiency would be approximately 9.8%. This assumes normal operation provides 650^oF flue gas at the air heater inlet (which would be entering the ID fan and exhausting through the stack if no heat recovery mechanism were to be installed).

Water Injection

Like FGR and reduction of combustion air temperature, water injection (WI) into the flame/combustion zone effectively reduces peak combustion flame temperature and has been demonstrated to be effective in reducing NO_x. With WI rates of about 0.2 to 0.6 pounds of water per pound of natural gas, NO_x reductions of up to 20% to 50% have been demonstrated on small boilers. This technique has also been applied to utility boilers. Although the potential NO_x reduction is relatively high, some studies have indicated that NO_x reduction in the range of 15% to 30% can be expected. To implement this technique, an injection lance, similar to an oil gun, with an atomizing tip is inserted into each burner to allow water injection. Since Units 6 and 7 were originally designed with oil guns inserted into the natural gas burners, this could be implemented fairly easily. However, because water injection quenches peak flame temperature, increased carbon monoxide can occur, and boiler efficiency suffers because of the added water in the flue gas. If WI in the amount of about 0.5 pounds per pound of fuel were done, boiler efficiency would be reduced by approximately 2%. The applicability of this technology on Boilers 6, 7 and 8 is questionable since there is the potential of a substantial boiler efficiency loss, depending on the quantity of water injected, along with the potential of adverse effect on flame stability and carbon monoxide formation. This technology could be useful for “polishing” application such that, if other applied technologies don't quite bring emissions levels to the required level of 0.08 lb/MMBtu, application of small amounts of WI could reduce NO_x by that amount necessary to meet the regulation but the adverse impact a small amount of WI would not be significant. It is noted that if Low NO_x Burners and/or FGR are used to meet the NO_x regulation limit, WI would likely not be employed.

Low NO_x Burners

Many burner manufacturers have developed low NO_x burners (LNB) that incorporate internal staging and operate at reduced NO_x levels without sacrificing boiler performance. One characteristic of these burners is that they provide stable combustion at low excess air levels, and combustion remains stable if FGR is introduced, even at high rates of FGR. For this project, two burner manufacturers, ZEECO and Babcock and Wilcox, were contacted for estimated costs and performance of their burners. Both companies indicated that their burners alone might be able to achieve a 50%- 60% reduction in NO_x from baseline levels of 0.16 to 0.20 Lb/MMBtu. However, depending on boiler and existing burner design, some FGR might be required to achieve the required NOx reductions at CCS. Both of these burner manufacturers also stated that further engineering design would be required to determine whether FGR would be required to achieve the NO_x level required for these units and what NO_x reduction from present levels would be achievable.

Combination of Technologies

As the preceding discussions indicated, most of the front-end NO_x reduction technologies alone might not be able to consistently achieve the required 0.08 lb/MMBtu NO_x levels required by the CSAPR rule. However, combinations of some of these technologies would undoubtedly be able to achieve the required NO_x level consistently. Combining LNB + OFA, LNB + FGR, OFA + FGR and combinations of these, and/or some of the other technologies discussed should enable compliance with 0.08 lb/MMBtu NO_x on a consistent basis. A plan should be developed to evaluate these combinations of technologies in a logical order that minimizes compliance costs.

3.3 Post Combustion NO_x Control Technologies

The NO_x study includes an evaluation of two back-end (or post-combustion) NO_x control technologies. These include Selective Non-Catalytic Reduction (SNCR) and Selective Catalytic Reduction (SCR). This section provides a brief description of the post-combustion technologies, along with comments on the applicability of the technologies to the CCS boilers.

SNCR

The SNCR technology involves the injection of an ammonia-containing reagent into the top of the boiler to reduce NO_x to elemental nitrogen. The process uses the heat of the boiler flue gas to reduce the NO_x without the use of a catalyst (hence, selective non-catalytic reduction). The process is applicable to the combustion of most fuel types but is more commonly applied to coal-fired boilers, rather than gas-fired boilers, as uncontrolled NO_x concentrations are typically higher.

A variety of ammonia-containing reagents can be used for SNCR. These include anhydrous ammonia, various concentrations of aqueous ammonia (up to 29%), and urea solutions, either purchased as a solution or produced on-site from solid urea. There are many factors that affect the selection of the reagent. Ammonia is less expensive but may require a permit for onsite storage. Urea is more expensive and may require corrosion additives for storage, but the injected urea-containing droplets can more easily penetrate into the boiler. Urea can also be converted to ammonia prior to injection. There is some evidence that ammonia-based systems can get higher NO_x reduction efficiencies, as it is not necessary to convert the urea to ammonia after injection. Since the quantity of reagent that would be required at Cleveland Cliffs is relatively small, the reagent of choice would probably be aqueous ammonia.

The factors that affect the effectiveness of SNCR include the following:

- The availability of a temperature "window" suitable for the NO_x reducing reactions;
- A residence time within the temperature window of at least 1 second;

- Feasibility of injecting the reagent at the appropriate location; and
- The uncontrolled NO_x concentration.

The location of the temperature window, and access to it, was not evaluated in this study. However, perhaps the most important factor affecting the feasibility of SNCR for the Cleveland Cliffs boilers is the inlet NO_x concentration. Considerable data have been collected over time showing that the effectiveness of SNCR decreases as the uncontrolled NO_x concentration goes down. Although the technology has the potential for removal efficiencies as high as 60%, the achievable removal efficiencies are less than 25% when the uncontrolled NO_x concentration is less than 0.2 lb/MMBtu. Consequently, SNCR would not be applicable, on its own, since NO_x reductions of at least 50 to 60% are needed.

SCR

The SCR technology involves the use of a reactor containing a catalyst. Ammonia is injected into the flue gas passing through the reactor where the ammonia selectively reduces NO_x to nitrogen (hence, selective catalytic reduction). The process is capable of large percentage reductions in NO_x and is applicable to a wide range of combustion sources and fuel types.

Most systems utilize either anhydrous or aqueous ammonia, although urea-to-ammonia systems are available. Anhydrous ammonia has a lower cost than aqueous ammonia but is more toxic than aqueous ammonia. For smaller installations, such as the CCS boilers, the reagent of choice would probably be aqueous ammonia.

The SCR process can achieve NO_x removal efficiencies in excess of 90%, even on large, coal-fired boilers. Since the removal efficiency required for the Cleveland Cliffs boilers is 70% at most, the capability of the technology exceeds what is required for compliance at Cleveland Cliffs.

4. NO_x Reduction Cost Estimates

Costs for the various NO_x control technologies are presented in this section. Costs are provided for both combustion modification approaches (front-end NO_x reduction) and post-combustion technologies. Capital cost estimates include installation. For annual costs, it is assumed that during the ozone season, either Unit 8, or alternatively, both Units 6 and 7, will be in operation for one-half of the time. Unit 8 is assumed to operate at 60% of its rated capacity when it is in operation and Units 6 and 7 are assumed to operate at 75% of their rated capacity when they are in operation. Costs are presented in 2023 dollars and are escalated from other time bases using the Chemical Engineering Plant Cost Index (CEPCI).

4.1 Costs for Combustion Modifications

Cost estimates for the various combustion modification/front end NO_x reduction technologies are presented in Table 4-1. The table includes ranges for capital and operating costs, and for potential NO_x reduction efficiencies, plus comments on the possible negative impacts of implementing each technology. The costs for LNB were received directly from ZEECO and Babcock and Wilcox, and the costs quoted by them include installation of the burners. Costs for the other technologies were derived from EPA documents (listed in Appendix A) using equipment ratio factors and adjusted to 2023 dollars using CEPCI factors. .

Table 4-1. Combustion Modifications Cost Summary

Technology	Capital Installed Cost, $	Annual Operating Cost, $	Potential NO_x Reduction	Comments
Combustion Tuning	50,000	N/A	5%-35%	Could require boiler equipment and controls upgrades for fans and air flow controls. Cost is for tuning all three units during one deployment (equipment cost is excluded).
Staged Combustion, OFA	750,000 – 1,200,000 (1)	N/A	15% - 50%	Could increase flue gas CO, change flame shape and characteristics.
Induced FGR	1,092,000 – 1,311,000 (1)	N/A	10% - 30%	NO_x removal dependent upon achievable FGR rate.
FGR	1,400,000 – 2,240,000 (1)	60,000	20% - 60%	Flame stability problems might occur with existing burners. Could change flame shape.
Combustion Air Temperature Reduction (CATR)		320,000 – 761,000 (1)	20% - 50%	Potential of significant boiler efficiency penalty. Cost of alternate heat recovery, air heater by-pass or increased power consumption of ID fan are not included. Estimated cost is loss of boiler efficiency.
Water Injection	100,000	60,000 – 141,000 (1)	15% - 30%	High boiler thermal performance penalty likely; possibility of high CO and flame stability problem.
LNB, Unit 6 & 7	2,900,000	N/A	40% - 60%	
LNB, Unit 8	3,575,000	N/A	40% - 60%	
LNB + FGR Unit 6 & 7	4,525,000	60,000	40% - 70%	
LNB + FGR Unit 8	5,578,000	60,000	40% - 70%	
LNB + OFA Units 6 & 7	3,770,000	N/A	40% - 60%	
LNB + OFA Unit 8	4,650,000	N/A	40% - 60%	

(1) Range shown is for Units 6 or 7 (lower value), and Unit 8 (higher value).

Tables 4-2 and 4-3 (for Units 6 or 7, and Unit 8, respectively) show annualized costs and cost effectiveness values for the combustion modification technologies. Note that the current value of the Capital Recovery Factor (CRF) used in Table 4-2 and 4-3 is based on the current prime interest rate of 8.5% and an expected equipment life of 30 years, as indicated by CCS personnel. The determination of $/Ton NO_x removed in these two tables is based on either both Units 6 and 7 being in service operating at about 75% of capacity for half of the ozone season (76 days) or Unit 8 being in service at about 60% capacity for half of the ozone season (the other 76 days). The uncontrolled NO_x level for all cases is 0.2 lb/MMBtu.

Since there is no common equipment used between the boilers for the combustion modification technologies, the cost to treat all three units is the sum of the costs from Tables 4-2 and 4-3. That is, the total cost is the sum of the costs in Table 4-2 (times two to include both Units 6 and 7) plus the costs in Table 4-3 for Unit 8. It is also noted that there is uncertainty regarding the labor cost for installation. Therefore, installed costs for each technology could be somewhat higher, depending on local labor costs.

Table 4-22. Units 6 & 7 Combustion Modification Cost Analysis

Technology	Comb Tuning	OFA	IFGR	FGR	CATR	WI	LNB Units 6 & 7	LNB + FGR Units 6 & 7	LNB + OFA Units 6 & 7
Installed Cost, $	16,667	750,000	1,092,000	1,638,000		100,000	2,900,000	4,525,000	3,770,000
Annual O&M Cost, $/yr				60,000	320,000	60,000		60,000	
CRF	0.0931	0.0931	0.0931	0.0931	0.0931	0.0931	0.0931	0.0931	0.0931
Annualized Capital Cost, $/yr	1,552	69,825	101,665	152,500	0	4,655	269,990	421,278	350,987
Annualized Capital Cost + O&M, $/yr	1,552	69,825	101,665	212,500	320,000	64,655	269,990	481,278	350,987
Estimated Removal Efficiency, %	20	33	20	40	40	23	50	60	60
Expected Emissions: lb/MMBtu	0.16	0.13	0.16	0.12	0.12	0.15	0.10	0.08	0.08
NO_x Removed, Tons/yr	12.40	20.46	12.40	24.80	24.80	14.26	31.00	37.20	37.20
$/Ton NO_x Removed	125	3,413	8,200	8,568	12,903	4,534	8,709	12,938	9,435

4.2 Costs for Post-Combustion Technologies

The post-combustion technologies evaluated in the study include Selective Noncatalytic Reduction (SNCR) and Selective Catalytic Reduction (SCR). Costs for both technologies were developed based on EPA's Air Pollution Cost Control Manual. The manual was updated in 2019 and includes costs in 2016 dollars based on costs gathered from many utility and industrial SNCR and SCR installations. Costs are provided in the manual that are applicable to both industrial and utility boilers fired by coal, oil, and natural gas with heat inputs greater than 250 MMBtu/hr. EPA has produced a spreadsheet to assist users in calculating costs based on their methodology, and their spreadsheet was used in the development of the post-combustion technology costs.

The costs derived from the EPA methodology were adjusted from 2016 to 2023 dollars using the Chemical Engineering Plant Cost Index (CEPCI) per the EPA methodology. Values of this index were 541.7 in 2016 and 803.4 in April 2023 (the most recently available index value). This results in a cost escalation factor of 1.48.

Table 4-3. Unit 8 Combustion Modifications Cost Analysis

Technology	Comb Tuning	OFA	IFGR	FGR	CATR	WI	LNB Unit 8	LNB + FGR Unit 8	LNB + OFA Unit 8
Installed Cost, $	16,667	1,200,000	1,311,000	1,966,000		100,000	3,575,000	5,578,000	4,650,000
Annual O&M Cost, $/yr				60,000	761,000	141,000		60,000	
CRF	0.0931	0.0931	0.0931	0.0931	0.0931	0.0931	0.0931	0.0931	0.0931
Annualized Capital Cost, $/yr	1,552	111,720	122,000	183,000	0	4,655	332,833	519,312	432,915
Annualized Capital Cost + O&M, $/yr	1,552	111,720	122,000	243,000	761,000	145,655	332,833	579,312	432,915
Estimated Removal Efficiency, %	20	33	20	40	40	23	50	60	60
Expected Emission: lb/MMBtu	0.16	0.13	0.16	0.12	0.12	0.15	0.10	0.08	0.08
NO_x Removed, Tons/yr	23.92	39.47	23.92	47.84	47.84	27.51	59.80	71.76	71.76
$/Ton NO_x Removed	65	2,831	5,100	5,080	15,907	5,295	5,566	8,073	6,033

For the purpose of calculating annual costs, it is assumed that the plant will operate Unit 8 half of the time (182 days per year) and both Units 6 and 7 for half of the time (182 days per year). Further, it is assumed that reagent injection only occurs during the ozone season (76 days of operation for Unit 8 and 76 days of operation for the combination of Units 6 and 7). Finally, it is assumed that Unit 8 operates at 60% of its rated capacity when in operation and that Units 6 and 7 operate at 75% of their rated capacities when they are in operation.

Indirect annual costs include primarily capital recovery. The capital recovery factor, calculated as 0.0931, is based on a 30-year equipment life and a Prime Interest Rate of 8.5%. The cost effectiveness values are based on the tons of NO_x removed during the ozone season.

SNCR

SNCR costs for Unit 8 and for Units 6 or 7 are provided in Tables 4-4 and 4-5, respectively. Capital costs include the SNCR equipment and balance-of-plant costs. Installation costs are taken as 30% of the equipment cost. As indicated in Tables 4-4 and 4-5, total installed capital costs for Unit 8, and for either Units 6 or 7, are $5.95 and $4.05 million, respectively. Direct annual costs are based on the use of 29% aqueous ammonia. This option is considerably less expensive than the cost for urea. Ammonia consumption is based on 25% NO_x removal using a relatively high Normal Stoichiometric Ratio (NSR) of 2.5. A high NSR would be required to even approach the level of performance required at Cleveland Cliffs, and one consequence of this would likely be high ammonia slip. Costs for other annual cost elements are listed in the tables.

Table 4-4. Unit 8 SNCR Cost Summary

Total Installed Capital Cost (TIC)			
Equipment Cost - SNCR		$1,756,894	Injectors, blowers, DCS & reagent system.
Equipment Cost - BOP		$2,819,065	Piping, water treatment for dilution water, ductwork, aux power modifications, other electrical and site upgrades.
Total Equipment Cost (TEC)	SNCR + BOP	$4,575,959	
Installation Costs (IC)	30% of TEC	$1,372,788	Engineering, construction management, installation, labor adjustment, and contractor profit & fees.
Total Installed Capital (TIC) Cost	TEC + IC	$5,948,746	
Direct Annual Costs (DAC)			
Annual Maintenance Cost (AMC)	1.5% of TIC	$89,231	
Annual Reagent Cost ($/gal of 29% ammonia)	$0.70	$71,379	Based on 2023 anhydrous ammonia cost.
Annual Electricity Cost ($/kWh)	$0.0530	$1,817	From Cleveland Cliffs.
Annual Water Cost ($/gal)	$0.0060	$1,044	
Additional Fuel Cost ($/MMBtu of natural gas)	$4.75	$8,517	From Cleveland Cliffs.
Total Direct Annual Cost (DAC)		$171,988	
Indirect Annual Cost (IDAC)			
Administrative Charges	3.0% of AMC	$2,677	
Prime Interest Rate, %	8.5		Current for August 2023.
Equipment Life, years	30		From Cleveland Cliffs.
Capital Recovery Factor (CRF)	0.0931		
Capital Recovery Costs	CRF x TIC	$553,828	
Total Indirect Annual Cost (IDAC)		$556,505	
Cost Effectiveness			
Total Annual Cost	DAC + IDAC	$728,493	
NO_x Removed, tons/yr	29.9		25% removal from 0.2 to 0.15 lb/MMBtu.
Cost Effectiveness, $/ton of NO_x removed		$24,361	

Table 4-5. Unit 6 or 7 SNCR Cost Summary

Total Installed Capital Cost (TIC)			
Equipment Cost - SNCR		$1,216,158	Injectors, blowers, DCS & reagent system.
Equipment Cost - BOP		$1,900,808	Piping, water treatment for dilution water, ductwork, aux power modifications, other electrical and site upgrades.
Total Equipment Cost (TEC)	SNCR + BOP	$3,116,966	
Installation Costs (IC)	30% of TEC	$935,090	Engineering, construction management, installation, labor adjustment, and contractor profit & fees.
Total Installed Capital (TIC) Cost	TEC + IC	$4,052,055	
Direct Annual Costs (DAC)			
Annual Maintenance Cost (AMC)	1.5% of TIC	$60,781	
Annual Reagent Cost ($/gal of 29% ammonia)	$0.70	$37,163	Based on 2023 anhydrous ammonia cost.
Annual Electricity Cost ($/kWh)	$0.0530	$946	From Cleveland Cliffs.
Annual Water Cost ($/gal)	$0.0060	$543	
Additional Fuel Cost ($/MMBtu of natural gas)	$4.75	$4,434	From Cleveland Cliffs.
Total Direct Annual Cost (DAC)		$103,867	
Indirect Annual Cost (IDAC)			
Administrative Charges	3.0% of AMC	$1,823	
Prime Interest Rate, %	8.5		Current for August 2023.
Equipment Life, years	30		From Cleveland Cliffs.
Capital Recovery Factor (CRF)	0.0931		
Capital Recovery Costs	CRF x TIC	$377,246	
Total Indirect Annual Cost (IDAC)		$379,070	
Cost Effectiveness			
Total Annual Cost	DAC + IDAC	$482,937	
NO_x Removed, tons/yr	15.6		25% removal from 0.2 to 0.08 lb/MMBtu.
Cost Effectiveness, $/ton of NO_x removed		$31,018	

Table 4-6 summarizes the capital and annualized costs for the application of SNCR to all three of the Cleveland Cliffs boilers. As shown in the table, total capital costs are estimated at $14.1 million and annualized costs are $1.31 million per year. In practice, actual costs for all three boilers would be lower than indicated in Table 4-6 because it would be possible to use common equipment for all three units. For example, a reagent preparation system for Unit 8 would be able to provide reagent for Units 6 and 7 with minimal modifications. Similar cost reductions should be available for other capital equipment. It is not possible to estimate the reduction in costs because itemized costs were not provided by the EPA. However, an approximate discount for capital costs might be in the range of 30%.

Table 4-6. Summary of SNCR Costs for all three CCS Boilers

	Total Installed Capital Cost ($ million	Annualized Capital Cost ($ million)	Total Annual Cost ($ million)	Tons of NO_x Removed (Ton/yr)	Cost Effectiveness ($/Ton)
Unit 6	4.05	0.38	0.48	15.6	31,018
Unit 7	4.05	0.38	0.48	15.6	31,018
Unit 8	5.95	0.55	0.73	29.9	24,361
Total	14.1	1.31	1.69	61.1	27,660
Discounted 30%	9.8	0.92	1.30	61.1	21,237

SCR

Costs for Units 8 and Units 6 or 7 are provided in Tables 4-7 and 4-8, respectively. For SCR, capital costs include all SCR equipment and balance-of-plant costs. Installation costs are taken as 30% of the equipment cost. As indicated in Tables 4-7 and 4-8, total installed capital costs for Unit 8, and for either Units 6 or 7, are $24.1 and $13.6 million, respectively. Direct annual costs are based on the use of 29% aqueous ammonia. Ammonia consumption is based on 70% NO_x removal. Costs for other annual cost elements are listed in the tables.

Table 4-9 summarizes the capital and annualized costs for the application of SCR to all three of the CCS boilers. As shown in the table, total capital costs are estimated at $51.3 million and annualized costs are $5.17 million per year. Cost effectiveness values are poor because of the high capital cost of the technology and because the uncontrolled NO_x concentration is low with operation of the process only during the ozone season. In practice, actual costs for all three boilers would be lower than indicated in Table 4-9 because it would be possible to use common equipment for all three units. For example, a reagent preparation system for Unit 8 would be able to provide reagent for Units 6 and 7 with minimal modifications. Similar cost reductions should be available for other capital equipment. It is not possible to estimate the reduction in costs because itemized costs were not provided by the EPA. However, an approximate discount for capital costs might be in the range of 30%.

4.3 Costs for Continuous Emissions Monitors

The CSAPR rule requires combustion units of the size operated by Cleveland Cliffs to report emissions of NO_x. This will require Cleveland Cliffs to install Continuous Emissions Monitor (CEMS) systems on each unit. The following discussion presents budgetary cost estimates for the required CEMS for the three units.

The cost estimate assumes that new environmentally controlled shelters would be required to house the CEMS and a new Data Acquisition System (DAS) for the CEMS. Depending on the proximity of the stacks to each other, it would be efficient and economical to house the CEMS for each stack into a single CEMS shelter. However, not knowing the details of the facility layout and the client preferences, two options have been costed: first option with each CEMS in individual shelters and the second option with all 3 CEMS in the same shelter. The CEMS shelter and the Data Acquisition System (DAS) makes up 35 – 45% of the total cost depending on the two options.

3 NO_x CEMS in Individual Shelters - $620,000

3 NO_x CEMS in a Single Shelter - $515,000

Table 4-7. Unit 8 SCR Cost Summary

Total Installed Capital Cost (TIC)			
Equipment Cost - SCR		$18,514,211	
Installation Costs (IC)	30% of TEC	$5,554,263	Engineering, construction management, installation, labor adjustment, and contractor profit & fees.
Total Installed Capital (TIC) Cost	TEC + IC	$24,068,475	
Direct Annual Costs (DAC)			
Annual Maintenance Cost (AMC)	0.5% of TIC	$120,342	
Annual Reagent Cost ($/gal of 29% ammonia)	$0.700	$20,985	Based on 2023 anhydrous ammonia cost.
Annual Electricity Cost ($/kWh)	$0.0530	$32,599	From Cleveland Cliffs.
Annual Catalyst Replacement Cost	$336/cf	$15,903	
Total Direct Annual Cost (DAC)		$189,829	
Indirect Annual Cost (IDAC)			
Administrative Charges (formula)		$2,254	
Prime Interest Rate, %	8.5		Current for August 2023.
Equipment Life, years	30		Per Cleveland Cliffs.
Capital Recovery Factor (CRF)	0.0931		
Capital Recovery Costs	CRF x TIC	$2,240,775	
Total Indirect Annual Cost (IDAC)		$2,243,029	
Cost Effectiveness			
Total Annual Cost	DAC + IDAC	$2,432,858	
NO_x Removed, tons/yr	83.7		70% removal from 0.2 to 0.06 lb/MMBtu.
Cost Effectiveness, $/ton of NO_x removed		$29,055	

Table 4-8. Units 6 or 7 SCR Cost Summary

Total Installed Capital Cost (TIC)			
Equipment Cost - SCR		$10,477,660	
Installation Costs (IC)	30% of TEC	$3,143,298	Engineering, construction management, installation, labor adjustment, and contractor profit & fees.
Total Installed Capital (TIC) Cost	TEC + IC	$13,620,958	
Direct Annual Costs (DAC)			
Annual Maintenance Cost (AMC)	0.5% of TIC	$68,105	
Annual Reagent Cost ($/gal of 29% ammonia)	$0.700	$10,926	Based on 2023 anhydrous ammonia cost.
Annual Electricity Cost ($/kWh)	$0.0530	$16,972	From Cleveland Cliffs.
Annual Catalyst Replacement Cost	$336/cf	$6,624	
Total Direct Annual Cost (DAC)		$102,627	
Indirect Annual Cost (IDAC)			
Administrative Charges (formula)		$1,627	
Prime Interest Rate, %	8.5		Current for August 2023.
Equipment Life, years	30		Per Cleveland Cliffs.
Capital Recovery Factor (CRF)	0.0931		
Capital Recovery Costs	CRF x TIC	$1,268,111	
Total Indirect Annual Cost (IDAC)		$1,269,738	
Cost Effectiveness			
Total Annual Cost	DAC + IDAC	$1,372,365	
NO_x Removed, tons/yr	43.6		70% removal from 0.2 to 0.06 lb/MMBtu.
Cost Effectiveness, $/ton of NO_x removed		$31,480	

Table 4-9. Summary of SCR Costs for all three CCS Boilers

	Total Installed Capital Cost ($ million)	Annualized Capital Cost ($ million)	Total Annual Cost ($ million)	Tons of NO_x Removed (Ton/yr)	Cost Effectiveness ($/Ton)
Unit 6	13.6	1.27	1.37	43.6	31,480
Unit 7	13.6	1.27	1.37	43.6	31,480
Unit 8	24.1	2.24	2.43	83.7	29,055
Total	51.3	4.78	5.17	170.9	30,252
Discounted 30%	34.4	3.20	3.59	141.2	25,453

The difference between a straight extractive CEMS (NO_x and oxygen analyzers) and a dilution CEMS (NO_x and carbon dioxide analyzers) is minimal because the cost of a gas conditioning system in the former is essentially offset by a more expensive dilution probe assembly, dilution control drawer and an air dryer/clean up system required for the latter. Most of the other components, especially the big cost items, are the same between both types of CEMS. It is estimated that the dilution CEMS would cost about 2% – 5% less than a straight extractive CEMS.

There are potential cost savings (compared to the costs shown above) by selecting a less expensive DAS provider than was used for this estimate, selecting a smaller CEMS shelter or using an existing one on site and selecting a different manufacturer for certain sample delivery components than what has been used.

Estimated costs shown above include:

- Environmentally controlled CEMS shelter.
- All CEMS equipment from sample probe tube in the stack to the CEMS shelter (probe assembly, heated sample line, gas conditioning system, sample flow/calibration control panel, gas analyzers, pumps, DAS (data logger + computer with reporting software), calibration gas regulators and miscellaneous components).
- Design and fabrication of 3 complete NO_x CEMS systems.
- System documentation (Drawings package, user manuals, etc.).
- Onsite CEMS installation support/oversight.
- Factory Acceptance Testing of the CEMS (not Initial Certification/RATA).
- Remote training on the use of the CEMS reporting software.

Other assumptions for these estimates are:

- CEMS shelter size – 10’ x 8’ x 8’ if individual shelters. Slightly larger (12’ x 8’ x 8’) if all 3 CEMS go into a single shelter.
- Heated sample line length: 150 ft.
- No stack gas flow rate monitoring equipment. Only NO_x and oxygen or carbon dioxide gas analyzers.
- On-site physical installation of CEMS shelter, stack components, heated sample lines, etc. to be performed by plant personnel. CEMS vendor to provide oversight/installation support.
- Initial certification testing (7-day CD test, RATA etc.) is not included in the cost.
- All wiring/communications between the CEMS equipment and the facility’s control room to be performed by plant personnel.
- All utility connections to the CEMS shelter (power, plant air and communications) to be provided by plant personnel.
- Stack ports with flanges to install sample probe assembly to be installed by plant personnel.
- Spare parts are not included in the cost estimates.

5. Conclusions and Recommendations

As the material presented in this report indicates, there are several viable technical approaches for reducing NO_x in the three boilers at Cleveland Cliffs. It is apparent that there is some uncertainty with respect to the degree of effectiveness of these technologies, and a range of removal efficiencies was provided in this report. This range reflects the varying performance of the technologies across a large number of boilers. In this report, we have tried to represent reasonable but conservative NO_x reduction estimates. However, further detailed engineering analyses, combined with emissions testing, will be needed to determine the actual performance of each technology and to refine their costs for the CCS boilers.

Table 5-1 summarizes the results of the study. The table includes the removal efficiency used in the cost calculations, along with capital costs and cost effectiveness values for both Units 6 or 7 and Unit 8. The results show that there are multiple combustion modifications that could reduce NO_x emissions; however, a combination of techniques may be required to achieve consistent emissions less than 0.08 lb/MMBtu. It will be important to develop a plan to evaluate the options and identify a control approach that minimizes costs. On the other hand, the post combustion technologies are not cost effective, due largely to the low uncontrolled NO_x levels. SNCR, by itself, would not be capable of meeting the emission limitation. Note that costs for implementing the post combustion technologies would be lower than indicated if all three boilers were controlled due to the use of common equipment (e.g., the reagent preparation systems).

Table 5-1. Summary of Capital Costs & Cost Effectiveness

Technology	Estimated Removal Efficiency (%)	Units 6 OR 7		Unit 8	
		Capital Cost ($)	Cost Effectiveness ($/Ton)	Capital Cost ($)	Cost Effectiveness ($/Ton)
Combustion Tuning	20	16,667	125	16,667	65
Staged Combustion, Over-Fire Air	33	750,000	3,400	1,200,000	2,800
Induced Flue Gas Recirculation	20	1,092,000	8,200	1,311,000	5,700
Flue Gas Recirculation	40	1,400,000	7,700	2,240,000	5,600
Combustion Air Temperature Reduction	40	0	12,900	0	12,900
Water Injection	23	100,000	4,500	100,000	5,300
Low NO_x Burners	50	2,900,000	8,700	3,575,000	5,600
Low NO_x Burners + Flue Gas Recirculation	60	4,525,000	12,900	5,578,000	8,100
Low NO_x Burners + Over-Fire Air	60	3,770,000	9,400	4,650,000	6,000
Selective Noncatalytic Reduction	25	4,050,000	31,000	5,950,000	24,361
Selective Catalytic Reduction	70	13,600,000	31,500	24,100,000	29,100

AECOM suggests the following approach for the evaluation of combustion modification technologies:

1. AECOM recommends performing combustion tuning as the initial step in the compliance plan. Effective combustion tuning, however, would require upgrades to the air and flue gas fans to incorporate either flow and pressure control dampers and/or Variable Frequency Drives (VFD) on the fans to control air flow to the boiler allowing for oxygen trim control. These changes would likely lead to reductions in NO_x and increases in boiler efficiency. These upgrades would not be required for the purpose of implementing OFA and FGR. Therefore, as

an option, the plant could elect to defer these upgrades until after installation of OFA and FGR, in the event that modest further reductions in NO_x emissions are required.

2. As one part of an initial investigation of options, select one of the smaller boilers (suggest Unit 7 since it is the only unit that has a test penetration in the stack for flue gas analysis) and install a FGR duct from the ID fan exit to the FD fan inlet. This duct should be equipped with a flow control damper and a flow measurement device (Annubar). The purpose of this would be to explore the effectiveness of induced FGR on NO_x reduction. In the event this test does not demonstrate effective NO_x reduction, the duct can be utilized as the FGR duct by installation of an FGR fan. After exploring IFGR, install an FGR fan and determine the effectiveness of FGR with the existing burners.

3. As another part of an initial investigation, investigate OFA on Unit 8. There are steel plates covering the furnace wall penetrations where pulverized coal and oil burners were once installed but have subsequently been removed, therefore, installation of over-fire air ducts is possible using these penetrations. These OFA ducts should extend from the tops of the windbox in each corner to an elevation of 8’ to 10’ above the top elevation of burners through the steel plates covering the locations of the removed coal and oil burners. These ducts should be equipped with air flow control dampers. Following installation of these OFA ducts, tests should be conducted to determine the effectiveness of OFA on this unit.

4. As a final part of an initial investigation, the burner vendors should be commissioned to perform a study to evaluate the effectiveness of LNB for both Units 6&7 and Unit 8. Ideally, the results of the study would include expected emissions for burners alone, burners with FGR, and updated installed cost estimates.

5. Evaluate all results from the initial investigation to help quantify the next steps toward compliance. For Units 6&7, the next step might include the installation of OFA, perhaps with other combustion technologies, or low-NO_x burners. Similarly, the next step on Unit 8 might include the installation of FGR, perhaps with other combustion technologies, or low-NO_x burners. The initial investigation is intended to provide the data needed to determine the most efficient and cost-effective path to compliance.

6. If the procedures followed above are partially effective but fall a small amount short of meeting the NO_x limit, other combustion techniques such as combustion tuning, a moderate reduction in the combustion air temperature and/or water injection in small amounts could be explored. If combustion air temperature and/or water injection quantity is small the adverse effect on boiler performance will be minimal.

Another factor that Cleveland Cliffs must consider is the time required for ordering and installation of applicable technologies. For LNB, from order to delivery of burners can be about 12 months and installation would require 4 to 6 weeks. The other combustion modification technologies discussed in this document can likely be installed and operational in 6 months to a year. Since the units at Cleveland Cliffs must be in compliance by May 1, 2026, Cleveland Cliffs has 2 years and 9 months to conduct investigations with some of the technologies discussed, to determine what path forward is most economically feasible and to install and activate NO_x reduction technologies that will bring them into compliance. Therefore, AECOM recommends proceeding as quickly as possible with the initial evaluation outlined above.

Appendix A Reference Documents

1. “Status Report on NO_x Controls for Gas Turbines/Cement Kilns/Industrial Boilers/Internal Combustion Engines, Technologies & Cost Effectiveness,” NESCAUM, December 2000.
2. U.S Environmental Protection Agency, Alternative Control Techniques Document – NO_x Emissions from Industrial/Commercial/Institutional (ICI) Boilers. EPA-453/R-94-022, March 1994.
3. Khan, Sikander, U.S. EPA, “Methodology, Assumptions, and References Preliminary NO_x Controls Cost Estimates for Industrial Boilers,” October-November 2003.
4. Control Techniques for Nitrogen Oxides Emissions from Stationary Sources – Revised Second Edition, U.S. EPA, Research Triangle Park, NC. Publication No. EPA-450/3-83-002. January 1983.
5. Summary of NO_x Control Technologies and their Availability and Extent of Application.” U.S. EPA, Research Triangle Park, NC. February 1992.
6. EPA Air Pollution Cost Manual, Seventh Edition, Chapter 1, Selective Noncatalytic Reduction, April 2019.
7. EPA Ari Pollution Cost Manual, Seventh Edition, Chapter 2, Selective Catalytic Reduction, June 2019.

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