Application for Prevention of Significant Deterioration (PSD) Review and Issuance of a Permit to Install (PTI) for a Proposed Hot Briquetted Iron (HBI) / Direct Reduced Iron (DRI) Project (Toledo HBI), Toledo, Ohio

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APPENDICES

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Appendix B    Site Layout and Process Flow Diagram
Appendix C    Emissions Calculations
Appendix D    BACT Impact Analysis Tables
Appendix E    Air Quality Modeling Report
1. Introduction and Summary

1.1 Introduction

IronUnits LLC (“IU”), a subsidiary of Cleveland-Cliffs Inc., is seeking authorization in the form of a Prevention of Significant Deterioration / Permit to Install for a proposed Hot Briquetted Iron (HBI) / Direct Reduced Iron (DRI) manufacturing facility (“HBI Facility”) at the Ironville brownfield site (“Ironville”) in Toledo, Lucas County, Ohio, altogether identified as the “Project.” The Project will utilize the MIDREX® gas-based direct reduction process to produce 2.48 million tons per year of HBI or DRI from taconite pellets (“oxide”). The Project will be located on an approximately 130-acre site adjacent to the southwest corner of Millard Ave and Front Street within the city of Toledo, in Lucas County, Ohio. The Project will rely on ships, trains, and trucks to transport various raw materials and products to and from the site.

The proposed Project constitutes a new major stationary source under the Prevention of Significant Deterioration (“PSD”) preconstruction permitting regulations and a new major source under the Title V operating permit regulations. This permit application contains all of the required information, analyses and demonstrations under the Ohio Environmental Protection Agency (“OEPA”) PSD and Permit to Install (“PTI”) programs and all other applicable federal and State air quality regulations. The OEPA’s PSD and PTI permitting programs are approved in Ohio’s State Implementation Plan (“SIP”) for all pollutants subject to regulation. Therefore, the PSD permit for the project will be issued under Ohio Administrative Code (OAC) 3475-31-11 through 20. OEPA’s permitting program applicability is explained in greater detail in section 4 of this application.

1.2 Project Schedule

IU plans to commence construction as soon as authorized by permit and within 18 months of the air permit issuance for the Project. IU is currently scheduled to begin actual construction by May 2018 and commercial operation around mid-2020.

1.3 Permit Application Required Content

This document is IU’s application for PSD and PTI permit approvals for the proposed Project authorizing construction and initial operation of the Project. This section is the introduction and summary of the application. Section 2 presents a description of the process and proposed Project. Project emissions and proposed limitations are presented in Section 3. Section 4 presents a regulatory applicability analysis. Section 5 presents the planned control technologies and proposed emissions limitations. Sections 6 and 7 present air quality analyses. Section 8 includes an additional impacts analysis. Section 9 briefly discusses Class I impacts evaluation. This application reflects a true, accurate and complete depiction of the Project based on the plant design, which was frozen as of August 31, 2017 to facilitate permitting, with limited changes reflected in the December 2017 updated application. As with any complicated construction project, changes may occur over time, and material project changes will be reflected in future application updates.
2. Project and Process Description

2.1 Project Overview

IU is proposing to construct the Project, a ~2.48 million tons per year HBI and DRI manufacturing facility in Toledo, Lucas County, Ohio. The Project will use taconite pellets (“oxide”) as raw material and produce highly metallized iron in the form of HBI or DRI. The proposed HBI Facility will use a reformer and a shaft furnace (combined to make up the MIDREX® process), to produce HBI and DRI using natural gas. The project design requires use of a reformer unit to generate reducing gas by reforming natural gas that will be used in the shaft furnace for producing DRI and HBI. Details of the proposed equipment are provided in this section.

2.2 Project Location

The Project will be located within the city of Toledo boundary, in Lucas County, Ohio. The Project site is across the street from the existing Midwest Terminals of Toledo Inc.’s material storage and handling operations, which will be contracted to provide services for the Project as described in subsection 2.4.1.2 The approximate Universal Transverse Mercator (UTM) coordinates of the site are 293,460 meters east and 4,616,477 meters north (UTM Zone 17, NAD 83). Figure 2-1 shows the general location of the Project. Figure 2-2 shows the specific Project location on a 7.5-minute U.S. Geological Survey (USGS) topographic map. Site layouts are provided in Appendix B.

The Project site is approximately 590 feet above mean sea level. The portion of Lucas County where the Project is located is classified as attainment or unclassified for all criteria pollutants.

2.3 Process Description

The Direct Reduction Iron (DRI) process consists of two main components, a Reformer (to produce the reducing agent) and the shaft furnace (where the reaction occurs). The DRI process converts pre-processed iron oxide pellets into highly metallized iron in the form of DRI, which is then briquetted to form HBI.

Gas Reforming
The primary raw material source to produce the reducing gas for the reduction process is natural gas. Natural gas is reacted with carbon dioxide and water vapor across a proprietary catalyst to produce a reducing gas rich in carbon monoxide and hydrogen. The important reforming reactions are:

1 Midwest Terminals of Toledo, Inc., 2863 Front Street, Toledo, OH 43605.
2 The proposed HBI Facility and Midwest Terminals are separate facilities that do not share common ownership or common control as described in subsection 4.1.2.1 of the application.
Figure 2-1. General Location of the Project
Figure 2-2. Specific Location of the Project
CH\(_4\) + CO\(_2\) → 2CO + 2H\(_2\)
CH\(_4\) + H\(_2\)O → CO + 3H\(_2\)

Both of these reforming reactions are endothermic and therefore require energy in the form of heat input. Heat input into the system will primarily be from recycled top gas fuel that is generated in the process supplemented by natural gas. The mixed fuel gas is combusted in the heater for the reformer.

**Oxide Reduction**
Most naturally occurring iron oxide has the chemical composition of hematite, Fe\(_2\)O\(_3\), and contains about 30 percent oxygen by weight. In the DRI process, the chemically bonded oxygen in the iron ore is removed at elevated temperatures by reacting with carbon monoxide (CO) and hydrogen (H\(_2\)) contained in a reducing gas to produce metallic iron (Fe), while liberating carbon dioxide (CO\(_2\)) and water vapor (H\(_2\)O). The primary reduction reactions are:

Fe\(_2\)O\(_3\) + 3H\(_2\) → 2Fe + 3H\(_2\)O
Fe\(_2\)O\(_3\) + 3CO → 2Fe + 3CO\(_2\)

### 2.4 Oxide Storage and Handling

Oxide will be transported to the site via ships or barges on the Maumee River and will be off-loaded to the adjacent Midwest Terminal facility. The self-unloading systems on these vessels will be used to unload the oxide to Midwest Terminal’s existing receiving hopper. The oxide will then be transferred within the Midwest Terminal property using existing belts, and a radial stacker. The Midwest Terminal radial stacker belt will place oxide in a new hopper (at Midwest facility) which feeds a belt conveyor to the proposed HBI Facility. Existing and proposed emissions units (EU) and control devices (CD) at the Midwest Terminal are presented in Table 2-1. The list of proposed equipment for the oxide handling and storage systems of the Project is provided in Table 2-2.

**Table 2-1. Equipment at the Midwest Terminal for Oxide Handling**

<table>
<thead>
<tr>
<th>EU ID</th>
<th>EU Description</th>
<th>Capacity / Throughput</th>
<th>Proposed Controls</th>
</tr>
</thead>
<tbody>
<tr>
<td>MTR-1</td>
<td>Boat unloading to hopper*</td>
<td>3,310 tons/hour</td>
<td>Water or chemical suppressant**</td>
</tr>
<tr>
<td>MTR-2</td>
<td>Hopper drop to conveyor*</td>
<td>3,310 tons/hour</td>
<td>Water or chemical suppressant**</td>
</tr>
<tr>
<td>MTR-3</td>
<td>Conveyor to stacker</td>
<td>3,310 tons/hour</td>
<td>Windshield</td>
</tr>
<tr>
<td>MTR-4</td>
<td>Stacker to hopper</td>
<td>3,310 tons/hour</td>
<td>Baghouse enclosure</td>
</tr>
<tr>
<td>MTR-5</td>
<td>Hopper to conveyor transfer</td>
<td>3,310 tons/hour</td>
<td>Baghouse enclosure</td>
</tr>
</tbody>
</table>

* MTR-1, MTR-2, and MTR-3 are existing operations at the Midwest Terminal facility. There will be no increase in hourly particulate matter emissions for these operations as a result of the project.

**Note, water/chemical suppressants to be applied as necessary based on weather conditions and other factors.
<table>
<thead>
<tr>
<th>EU ID</th>
<th>EU Description</th>
<th>Capacity / Throughput</th>
<th>Proposed Controls</th>
</tr>
</thead>
<tbody>
<tr>
<td>TR-1</td>
<td>Oxide conveyor from Midwest Terminal to Oxide Transfer-Tower-I</td>
<td>3,310 tons/hour</td>
<td>Baghouse</td>
</tr>
<tr>
<td>TR-2</td>
<td>Oxide conveyor from Oxide Transfer-Tower-I to Stacker-Bucket-Reclaim Machine</td>
<td>3,310 tons/hour</td>
<td>Windshield</td>
</tr>
<tr>
<td>WE-1</td>
<td>Oxide stockpiles</td>
<td>772,000 tons</td>
<td></td>
</tr>
<tr>
<td>TR-3</td>
<td>Stacker-Bucket-Reclaim Machine conveyor drop to stockpile (stacking)</td>
<td>3,310 tons/hour</td>
<td>Water or chemical suppressant*</td>
</tr>
<tr>
<td>TR-4</td>
<td>Stacker-Bucket-Reclaim Machine bucket drop to conveyor (reclaiming)</td>
<td>1,220 tons/hour</td>
<td>Water or chemical suppressant*</td>
</tr>
<tr>
<td>TR-5</td>
<td>Oxide reclaiming conveyor drop to conveyor</td>
<td>1,220 tons/hour</td>
<td>Windshield</td>
</tr>
<tr>
<td>TR-6</td>
<td>Oxide conveyor drop to Oxide Transfer-Tower-II</td>
<td>1,220 tons/hour</td>
<td>Baghouse</td>
</tr>
<tr>
<td>TR-7</td>
<td>Oxide conveyor drop to Oxide Transfer-Tower-III</td>
<td>1,220 tons/hour</td>
<td>Baghouse</td>
</tr>
<tr>
<td>TR-8</td>
<td>Oxide lumps drop from conveyor to stockpile</td>
<td>1.2 tons/hour</td>
<td>Water or chemical suppressant*</td>
</tr>
<tr>
<td>WE-2</td>
<td>Lumps stockpile</td>
<td>1,200 tons</td>
<td>Chemical stabilization/water ring*</td>
</tr>
<tr>
<td>FEL-1</td>
<td>Front end loader (FEL) oxide lumps reclaim fugitive from unpaved surface</td>
<td>28 tons/hour</td>
<td>Chemical stabilization*</td>
</tr>
<tr>
<td>TR-9</td>
<td>Oxide lumps drop from FEL to truck</td>
<td>28 tons/hour</td>
<td>None</td>
</tr>
<tr>
<td>HR-1</td>
<td>Haul road truck traffic for oxide lumps transport</td>
<td>28 tons/hour</td>
<td>Watering &amp; sweeping</td>
</tr>
<tr>
<td>TR-10</td>
<td>Three oxide day bins and bin vents</td>
<td>1,220 tons/hour and three 3,300 tons</td>
<td>Baghouse</td>
</tr>
<tr>
<td>TR-11</td>
<td>Oxide fines drop from conveyor to stockpile</td>
<td>24 tons/hour</td>
<td>Water or chemical suppressant*</td>
</tr>
<tr>
<td>WE-3</td>
<td>Fines stockpile</td>
<td>5,600 tons</td>
<td>Chemical stabilization/Water ring*</td>
</tr>
<tr>
<td>FEL-2</td>
<td>FEL oxide fines reclaim fugitive from unpaved surface</td>
<td>28 tons/hour</td>
<td>Chemical stabilization*</td>
</tr>
<tr>
<td>TR-12</td>
<td>Oxide fines drop from FEL to truck</td>
<td>28 tons/hour</td>
<td>None</td>
</tr>
<tr>
<td>HR-2</td>
<td>Haul road truck traffic for oxide fines transport</td>
<td>28 tons/hour</td>
<td>Watering &amp; sweeping</td>
</tr>
<tr>
<td>SR-1</td>
<td>Oxide screens</td>
<td>470 tons/hour</td>
<td>Baghouse</td>
</tr>
<tr>
<td>TR-13</td>
<td>Oxide drop from conveyor to bucket elevator in core plant</td>
<td>470 tons/hour</td>
<td>Baghouse</td>
</tr>
<tr>
<td>TR-14</td>
<td>Oxide coating storage and mixing and fines transfer</td>
<td></td>
<td>Baghouse</td>
</tr>
<tr>
<td>HR-3</td>
<td>Oxide coating truck transport</td>
<td>28 tons/hour</td>
<td>Watering &amp; sweeping</td>
</tr>
<tr>
<td>TR-15</td>
<td>REMET conveyor to stockpile</td>
<td>14 tons/hour</td>
<td>None</td>
</tr>
<tr>
<td>WE-4</td>
<td>REMET stockpile</td>
<td>6,700 tons</td>
<td>Windshield</td>
</tr>
<tr>
<td>FEL-3</td>
<td>FEL REMET reclaim fugitive from unpaved surfaces</td>
<td>29 tons/hour</td>
<td>Chemical stabilization*</td>
</tr>
<tr>
<td>TR-16</td>
<td>REMET drop from FEL to hopper</td>
<td>29 tons/hour</td>
<td>None</td>
</tr>
</tbody>
</table>

* Note, water or chemical suppressants to be applied as necessary based on weather conditions and other factors.

At the HBI Facility, the oxide will be stored in one of the two stockpiles using a stacker-bucket-reclaimer machine. The same machine will use its rotary bucket-reclaimer system to reclaim the
oxide material. The oxide will next be conveyed to an oversized lump screen where larger size oxide lumps will be separated. The oxide lumps will be stockpiled and thereafter reclaimed using a front end loader and shipped offsite via trucks. The reclaimed oxide material from the screen will be transferred to three oxide day-bins for storage.

A belt conveyor will transfer the oxide from weigh belt feeders under the day-bins to the screening building. During HBI manufacturing, a small fraction of off-spec product is rejected (“REMET”). This REMET is stored on site in a stockpile and then reclaimed by a front end loader and re-introduced to the process after the oxide day-bins. Oxide and REMET fines will be separated in the screening process using two screens. The fines will be stockpiled at the site, reclaimed using a front end loader and shipped off-site via trucks. The oxide material passes through a coating station which applies a slurry consisting of a mixture of water and either, Portland Cement, burnt lime, hydrated lime, hydrated dolomite, calcitic limestone, or dolomitic limestone at an application rate of 0 to 10 kg per ton of oxide. Emissions estimates are made assuming 2.5 kg per ton of oxide. This coating assists in the flow of material in the direct reduction process and reduces the generation of fugitive dust from the oxide as it is handled and transferred through the process.

The furnace feed conveyor is a vertical, pocket type conveyor with flexible side walls that delivers the coated oxide to the top of the furnace tower. The enclosed furnace feed conveyor discharges to the charge hopper located at the top of the DRI reactor (shaft furnace).

2.5 Core HBI Plant Processes

The following sections describe the main components of the core HBI Plant process. The list of proposed equipment for Core HBI Plant is provided in Table 2-3.

<table>
<thead>
<tr>
<th>EU ID</th>
<th>EU Description</th>
<th>Capacity / Throughput</th>
<th>Proposed Controls</th>
</tr>
</thead>
<tbody>
<tr>
<td>TR-28</td>
<td>Charge hopper exhaust</td>
<td>470 tons/hour (oxide)</td>
<td>Scrubber</td>
</tr>
<tr>
<td>P-1</td>
<td>Bottom seal gas exhaust</td>
<td>320 tons/hour (HBI)</td>
<td>Scrubber</td>
</tr>
<tr>
<td>P-2</td>
<td>Reformer flue gas exhaust (top gas &amp; natural gas)</td>
<td>1,687 MMBtu/hour (HHV)</td>
<td>Low NOx burners (LNB)</td>
</tr>
<tr>
<td>P-3</td>
<td>Hot briquette exhaust</td>
<td>320 tons/hour (HBI)</td>
<td>Scrubber</td>
</tr>
<tr>
<td>P-4</td>
<td>Briquette cooling system vapor removal vent</td>
<td>320 tons/hour (HBI)</td>
<td>Scrubber</td>
</tr>
<tr>
<td>P-5</td>
<td>Degasser exhaust</td>
<td>None</td>
<td></td>
</tr>
<tr>
<td>P-6</td>
<td>Pressure Relief Vent Flare</td>
<td>1,678 MMBtu/hour (during upset)</td>
<td>Designed efficiency</td>
</tr>
<tr>
<td>P-7</td>
<td>Cooling tower</td>
<td>24,766 gallon/min (circulation rate)</td>
<td>High efficiency drift eliminators</td>
</tr>
<tr>
<td>P-8</td>
<td>Emergency diesel fire water booster pump</td>
<td>186 kW</td>
<td>Low sulfur diesel fuel</td>
</tr>
<tr>
<td>P-9</td>
<td>Emergency diesel generator</td>
<td>2,000 kW</td>
<td>Low sulfur diesel fuel</td>
</tr>
</tbody>
</table>
2.5.1 Reduction Furnace Tower

Oxide enters the furnace through the upper dynamic seal leg and is uniformly distributed in the vessel by symmetrical feed pipes. A dynamic seal is created by a small flow of inert seal gas into the upper seal leg of the furnace. This small flow of inert seal gas into the furnace through the seal leg prevents the escape of furnace gases to the atmosphere, while still allowing the free flow of material by gravity into the furnace.

The oxide is reduced to metallic iron in the upper portion of the furnace (reduction zone) by contact with hot hydrogen and carbon monoxide gases that are generated in the reformer and flow counter-current to the descending iron oxide. The temperature of the reducing gas is typically 840 - 1,000 °C, depending on the specific reactor operating conditions. Specially designed inlet ports (tuyeres) ensure that the reducing gases flow uniformly to the furnace burden. Spent reducing gas exits near the top of the reactor and are reused in the process gas system. The product material typically spends 3-4 hours in the reactor in order to achieve the desired product metallization and is then discharged from the furnace cone at temperatures above 700 °C. The discharge zone consists of the refractory lined furnace cone equipped with hydraulically operated burden feeders and a flow-aid insert to facilitate the flow of the material within the cone.

Seal gas (further described in 2.5.5) is used to pressurize the top of the reactor so that the reducing gases do not vent to the atmosphere. However, during startup and shutdown and upset conditions, the system is designed to vent gas through the top gas scrubber and on to a flare. Inert nitrogen will be used as the seal gas for the furnace bottom seal leg and for some other applications. Nitrogen gas will be supplied by the onsite nitrogen plant. Figure 2-3 presents a process flow diagram for the proposed project. In event of a process malfunction or disruptions in nitrogen seal gas availability, the system is designed to use reformer flue gas as seal gas for safe operation of the DRI reactor.
2.5.2 Process Gas Circuit

Spent reducing gas (top gas) exits the reduction zone of the furnace through the refractory lined top gas duct and enters the top gas scrubber to be cleaned, cooled and reused in the process without discharge to atmosphere. Inside the top gas scrubber, the gas passes through two distinct zones. First the gas flows through the wet venturi portion of the scrubber where it is rapidly cooled, and solids in the gas stream are wetted and removed. Then the warm gas is split into two streams that pass through two parallel packed beds (for additional cooling) and two sets of mist eliminators (to remove water droplets) within the scrubber. Figure 2-4 is schematic representation of the top gas flows.

After scrubbing and cooling, approximately two-thirds of the clean top gas (now called process gas) flows through a second set of mist eliminators. The process gas section uses a blend of hot and cold process water for its spray water, the temperature of which determines the reformed gas hydrogen to carbon monoxide ratio, an important operating parameter. The process gas is then routed to the inlet of the first stage process gas compressor, followed by a second compressor. These compressors are centrifugal type machines designated as first stage and second stage process gas compressors. After compression, the process gas is mixed with natural gas and preheated to form the feed gas for the reformer. The other one-third of the cleaned top gas (now called top gas fuel) is mixed with a small amount of natural gas and then passed through a mist eliminator to remove water droplets before fueling the reformer main burners to beneficially use the Btu value of the top gas fuel.

Figure 2-3. MIDREX® Core Plant Process Flow Diagram

Source: MIDREX® process as shown in presentation by A C R Das of Ministry of Steel Govt. of India
It is important to note that the Top Gas Scrubber is not a control device but a process device that cleans the gas for use within the process as feed gas and fuel. The process gas system does not discharge to atmosphere under normal design conditions and vents to a flare under process upset conditions.

2.5.3 **Reformer**

The reformer generates the hot reducing gas (H₂ and CO) required to reduce the iron oxide in the shaft furnace. It is a proprietary design which heats and reforms the feed gas inside the reformer tubes. The proprietary reformer tubes reforms natural gas across a proprietary catalyst with both the water vapor and CO₂ in the feed gas. Heat for the reforming reactions is supplied by floor fired low-NOx main burners, which are located on the bottom of the reformer box between tube rows and between the outside tube rows and the reformer wall. The air required for combustion is preheated in the heat recovery system before being directed to the burners with the main air blower. The reformer box is thermally insulated with refractory material. Natural gas-fired low NOx auxiliary burners maintain the reformer box temperature during plant idle conditions to minimize both restart time and thermal cycling of the reformer tubes. The auxiliary burners remain on during normal operation as well, but at a low fire rate.

The reformer bays have flue gas ports sized to ensure uniform heat distribution along the reformer length. The flue gas headers are refractory lined and expansion joints are provided between the single sections of the headers to compensate for thermal expansion. The flue gas
exiting the reformer box via the flue gas headers flows to the heat recovery system where the waste heat is recovered.

### 2.5.4 Heat Recovery System

The reformer flue gas exits on both sides of the reformer and enters the parallel train heat recovery system. Each parallel system contains combustion air pre-heaters and feed gas pre-heaters, all of which consist of alloy bundle-type heat exchangers suspended in the refractory-lined heat recovery ducts. The combustion air pre-heaters are designed to preheat the combustion air to about 600 °C in two stages. The feed gas pre-heaters, located downstream of the combustion air pre-heater, heat the feed gas to approximately 600 °C, as well. Top gas fuel and natural gas are also preheated.

The flue gas exits the parallel heat recovery system through a common flue gas hot fan which generates the required suction to pull the flue gas from the reformer combustion furnace. The gases pass through the heat recovery system and out to the atmosphere via the flue gas stack. The heat recovery system increases the reformer capacity and reduces the net plant energy consumption by approximately 25-30 percent over previous versions of the MIDREX process.

### 2.5.5 Seal Gas and Purge Gas System

Inert seal gas for the plant, which is used primarily for sealing the top of the furnace, is provided by the seal gas generation system. This system takes hot reformer flue gas and cools it in a seal gas cooler. The seal gas cooler is a packed bed, direct-contact type cooler which cools the reformer flue gas to near ambient temperature. The cooled seal gas is then compressed by a positive displacement type compressor and then cooled in a shell and tube aftercooler to remove the heat of compression. The cooled seal gas passes through a mist eliminator and seal gas dryer. The seal gas dryer is a refrigerant type unit equipped with a stand-by compressor that removes moisture from the wet seal gas. This dry seal gas is then distributed to various plant users.

IU is using seal gas for the top seal of the furnace and N\(_2\) as seal gas for the bottom seal of the furnace.\(^3\) N\(_2\) gas will be generated from an on-site nitrogen plant.

The furnace bottom seal will use nitrogen to reduce the release of CO emissions from the bottom seal gas stack. The bottom seal gas (nitrogen) is vented through a vent line and collected in the dilution hood, which captures sufficient air to maintain a mixture of gases that remains below minimum explosive limits in the dust collection system. The mixture passes to the dust collection scrubber where entrained dust particles are removed and then the gas is exhausted through the bottom seal dust collection fan and stack.

A bottom seal gas compressor provides dry seal gas to the top seal leg of the furnace and some other process uses. In an emergency (e.g. gaseous nitrogen is not available), bottom seal gas can be used as backup for the furnace bottom seal.

The hot reduced material is discharged from the furnace through the dynamic seal leg and a hydraulically driven variable speed hot wiper bar. The hot material flows across the wiper bar and then passes through a set of hydraulically driven screens, which limit the maximum size of

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\(^3\) Use of \(N_2\) will significantly reduce process CO emissions from the bottom seal gas.
the product passing into the surge hopper of the product discharge chamber. The material is
discharged from the surge hopper into one or more of several feed legs. These feed legs connect
directly to either a briquette machine or the bypass feed screw.

2.5.6 Hot Briquetting System

The briquetting section includes briquette machines, briquette strand separators, HBI cooling
conveyors, and one bypass line. Hot DRI is supplied to each briquette machine by a screw
feeder. The continuous briquette strand that exits the briquetting machine is fed to the strand
separators to break the strands into individual briquettes, though some will contain more than
one, which are then fed to the HBI cooling system for slow cooling and discharge to the product
handling system. Off-specification product (REMET) produced during plant start-up or process
upset bypasses the briquette machines and is discharged through a bypass feed leg to the bypass
discharge feeder and then to the HBI cooling system.

The briquetting dust collection system is designed to minimize the escape of dust at the briquette
machines. The system consists of an exhaust fan, an additional air valve, a dust collection
scrubber, a sump, an exhaust stack, and associated ducts, hoods, pumps and valves. Dusty air and
seal gas are collected and conveyed at a sufficient velocity to prevent settling and accumulation
within the ducts. The gas stream then enters a wet venturi scrubber where water is sprayed onto
the dust particles to create a slurry. The slurry is discharged from the scrubber and pumped to the
basin upstream of the clarifier. Cleaned gases are pulled from the dust collection system by the
exhaust fan and discharged into the atmosphere through a stack.

The HBI cooling conveyors spray water to cool the HBI and are equipped with vapor hoods to
remove steam created by the process. Most of the mist vaporizes on contact with the hot HBI.
The vapor will pass through a cooler to condense most of the vapor which will then be exhausted
to the atmosphere via vapor exhaust fans. The vapor removal system consists of ducts and fans
designed to capture and minimize the release of steam into the briquette area. Outside air ducts
will be directly connected to each vapor hood, and vapor removal fans will supply the required
amount of unheated outside air directly into the vapor hoods. Spray cooling water that does not
vaporize will drain into collection pans routed to a sump and then to the waste water facility.

2.5.7 Pressure Relief Vent (Flare)

The process gas circuit will also include an elevated flare with natural gas pilot. The flare is used
during the Core Plant startup, shutdown, and upset events. During the plant startup, the flare is
used to purge the process gas system of air and vent process gas to stabilize the process gas
system. For the plant shutdown, process gasses inside the circuit are vented to the flare for
combustion. Flaring during startup or shutdown has a typical duration of less than 2 hours.

2.5.8 Machinery and Process Cooling Water System

The water system consists of a machinery cooling water circuit and a process cooling water
circuit.

The machinery cooling water is a closed circuit that supplies cooling water to all indirect coolers
such as burden feeders, rotating equipment lubrication oil, heat exchangers, etc. It consists of
circulation pumps, a sump, plate and frame heat exchangers, and a scaling/corrosion inhibitor
dosing system. Circulation pumps circulate hot water from the machinery cooling water sump
through the heat exchanger on one side while cold process water is pumped through on the other side to cool the machinery cooling water. A head tank is used to supply cooling water to the water cooled furnace equipment.

The process cooling water circuit supplies cooling water to the direct contact coolers and the process users, such as the top gas scrubber and the dust collection systems. It also provides the cooling water for the machinery cooling water heat exchangers. The process cooling water system consists of a sump, circulation pumps, process water cooling towers, and a clarifier system. Dirty, hot process water flows from the users to the clarifier. A dosing system injects a flocculating agent into the clarifier causing particulate matter to settle. Underflow from the clarifier is sent as a slurry to belt filters for de-watering and the excess water is sent to the clarifier. The water in the process water sump is cooled by passing through the process water cooling tower.

2.5.9 Cooling Tower

The closed-loop cooling system provides water cooling for the Core Plant operations. The water flow requirements for the Core Plant are combined into a common system that uses a closed cycle cooling water rated at 24,766 gallons per minute to provide the cooling necessary for maximum performance and efficiency of the system.

IU is proposing to use a conventional wet cooling tower system. The mechanical induced-draft cooling tower design will be cross flow cooling tower with high efficiency drift eliminator system.

2.5.10 Emergency Fire Water Booster

A 186 kW (250 HP) emergency fire water booster pump powered by a diesel-fired (compression ignition) reciprocating internal combustion engine (RICE) will be installed. The emergency fire-pump will be operated during emergency situations and for equipment maintenance and testing requirements. IU is planning to install a U.S. EPA certified emergency generator engine and limit its operation to no greater than 500 hours per year.

2.5.11 Emergency Generator

A 2000 kW (2,700 HP) emergency generator powered by a diesel-fired (compression ignition) reciprocating internal combustion engine (RICE) will be installed. The emergency generator will be operated during emergency situations and for equipment maintenance and testing requirements. IU is planning to install a U.S. EPA certified emergency generator engine and limit its operation to no greater than 500 hours per year.

2.6 HBI/DRI Handling

After the DRI/HBI (hereafter collectively referred to as “HBI”) is produced in the core plant, the cooled HBI will be conveyed using conveyors to a stacker that will stockpile the HBI. The HBI will be reclaimed using front end loaders to a system of two hoppers that will transfer the material to a set of conveyors. The conveyors will transfer the HBI to a loadout bin inside a loadout building to load the material to trains and/or trucks. HBI transport by a mix of truck and trains represents worst case emissions because transport by train only scenario eliminates
emissions from truck travel on haul roads. List of the proposed equipment for the HBI handling and storage systems at the HBI Facility is provided in Table 2-4.

**Table 2-4. Equipment at the HBI Facility for HBI Handling**

<table>
<thead>
<tr>
<th>EU ID</th>
<th>EU Description</th>
<th>Capacity / Throughput</th>
<th>Proposed Controls</th>
</tr>
</thead>
<tbody>
<tr>
<td>TR-17, TR-18</td>
<td>Three transfer towers for HBI conveyors</td>
<td>320 tons/hour</td>
<td>Scrubbers (2)</td>
</tr>
<tr>
<td>TR-19</td>
<td>HBI conveyor to stacker</td>
<td>320 tons/hour</td>
<td>Windshield</td>
</tr>
<tr>
<td>TR-20</td>
<td>HBI stacker conveyor drop to stockpile</td>
<td>320 tons/hour</td>
<td>Water or chemical suppressant*</td>
</tr>
</tbody>
</table>
| WE-5  | HBI stockpile wind erosion                            | 111,000 tons          | Chemical stabilization/  
|       |                                                      |                       | watering*                         |
| FEL-4 | HBI reclaim FEL fugitive                              | 566 tons/hour         | Chemical stabilization*            |
| TR-21 | HBI reclaim drop from FEL to hopper (2)               | 566 tons/hour         | Water or chemical suppressant*    |
| TR-22 | HBI hopper(2) to conveyor transfer points            | 566 tons/hour         | Enclosure                         |
| TR-23 | HBI conveyors with transfer tower                     | 566 tons/hour         | Scrubber                           |
| TR-24 | HBI conveyor to loading bin and transfer to train or truck | 566 tons/hour         | Scrubber                           |
| TR-25 | Truck loadout building and bin capture                | 170 tons/hour         | Scrubber                           |
| TR-26 | Building fugitive from HBI loading to train           | 566 tons/hour         | Enclosure with strip curtains and water sprays or chemical suppressant* |
| TR-27 | Building fugitive from HBI loading to trucks (30% of maximum daily rate) | 170 tons/hour         | Enclosure                         |
| HR-4  | HBI truck transport on paved haul roads               | 170 tons/hour         | Watering & sweeping               |

*Note, water or chemical suppressants to be applied as necessary based on weather conditions and other factors.*
3. **Project Emissions**

The Project will be a new stationary source. Therefore, the potential to emit (PTE) of regulated NSR pollutants from the proposed equipment is used for air permitting purposes. Equipment proposed under this project includes the DRI reactor, reformer and other ancillary equipment. This section describes the Project emissions calculations for regulated NSR pollutants and hazardous air pollutants (HAPs).

### 3.1 Regulated NSR Pollutants Emissions

This section summarizes PTE calculations and resulting emissions rates for regulated NSR pollutants from the emissions units proposed as part of the Project. Detailed emissions calculations are provided in Appendix C of this application. The regulated NSR pollutants included here are particulate matter (PM), particulate matter equal to or less than an aerodynamic diameter of nominally 10 µm (PM10) and 2.5 µm (PM2.5), oxides of nitrogen (NOx), carbon monoxide (CO), volatile or organic compounds (VOC), sulfur dioxide (SO₂), lead (Pb), and greenhouse gases (GHGs) as carbon dioxide equivalent (CO₂e). CO₂e is calculated in accordance with 40 CFR §52.21(b)(49)(ii) using the mass emission rates of six GHGs defined in 40 CFR §52.21(b)(49)(i) and corresponding global warming potential (GWP) published in 40 CFR Part 98, Subpart A, Table A-1. For this application, Table A-1 GWPs from the July 1, 2015 version of the 40 CFR Part 98 are used. The OEPA application forms (Appendix A) require uncontrolled PTE information. Where this information was not readily available, we conservatively back calculated uncontrolled PTE using the controlled emission rate and the control efficiency for the control device.

#### 3.1.1 HBI Core Plant Emissions

Exhaust gases are emitted from combustion of fuel in the Reformer and flare. In addition, some of the seal gas systems release exhaust gases from the furnace charge hopper, bottom seal gas and hot briquette process. The main components of these gaseous streams are: nitrogen, water vapor, carbon dioxide, and oxygen. Other compounds in the exhaust gases are particulate matter, SO₂, NOx, and CO.

A flaring system is proposed for the purpose of combusting excess process gas produced during plant startup and shutdowns when the plant gas circuits are purged. The flare will be operational only during startup or shutdown events and to address upset conditions, not during normal operations. Natural gas pilot lights will remain lit, on standby. The flare is designed to nearly completely oxidize the process gas.

Some equipment related with solids handling, such as the reactor charge bins or bottom seal gas exhaust are provided with atmospheric vents/exhausts. These units mostly release nitrogen, (inert gas used to displace air) and particulate matter. Table 3-1 presents the key parameters for estimating PTE of the proposed HBI Core Plant.

---

4 The aggregate group of six greenhouse gases are: carbon dioxide, nitrous oxide, methane, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. (40 CFR § 52.21(b)(49)(i))
### Table 3-1. Key Parameters for Estimating PTE for the HBI Core Plant

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Units</th>
<th>Charge Hopper Scrubber</th>
<th>Bottom Seal Gas Exhaust</th>
<th>Reformer Exhaust</th>
<th>Hot Briquette Exhaust</th>
<th>Briquette Cooling Vent</th>
<th>Degasser Exhaust</th>
<th>Flare</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>TR-28</td>
<td>P-1</td>
<td>P-2</td>
<td>P-3</td>
<td>P-4</td>
<td>P-5</td>
<td>P-6</td>
</tr>
<tr>
<td>Fuel use</td>
<td>MMBtu/hr</td>
<td>-</td>
<td>1.687</td>
<td>1.678/0.7</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Flow</td>
<td>scfm</td>
<td>1.579</td>
<td>40.678</td>
<td>305.347</td>
<td>63.228</td>
<td>58.111</td>
<td>15.002</td>
<td>105</td>
</tr>
<tr>
<td>PM (F)</td>
<td>gr/dscf</td>
<td>0.007</td>
<td>0.007</td>
<td>0.0031</td>
<td>0.0073</td>
<td>0.008</td>
<td>0.0019**</td>
<td></td>
</tr>
<tr>
<td>PM10 (F)*</td>
<td>gr/dscf</td>
<td>0.007</td>
<td>0.007</td>
<td>0.0031</td>
<td>0.0073</td>
<td>0.008</td>
<td>0.0019**</td>
<td></td>
</tr>
<tr>
<td>PM2.5 (F)*</td>
<td>gr/dscf</td>
<td>0.007</td>
<td>0.007</td>
<td>0.0031</td>
<td>0.0073</td>
<td>0.008</td>
<td>0.0019**</td>
<td></td>
</tr>
<tr>
<td>PM (C)</td>
<td>gr/dscf</td>
<td>0.00015</td>
<td>0.0041</td>
<td>0.00024</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NOx</td>
<td>ppmvd</td>
<td>178.3</td>
<td>1.5</td>
<td>46</td>
<td>8.7</td>
<td>0.068**</td>
<td>0.0066**</td>
<td></td>
</tr>
<tr>
<td>SO2</td>
<td>ppmvd</td>
<td>153</td>
<td>0.6</td>
<td>1.4</td>
<td>0.3</td>
<td>0.0006**</td>
<td></td>
<td></td>
</tr>
<tr>
<td>CO</td>
<td>ppmvd</td>
<td>410</td>
<td>243</td>
<td>39</td>
<td>18</td>
<td>3.10**</td>
<td></td>
<td></td>
</tr>
<tr>
<td>VOC</td>
<td>lb/MMBtu</td>
<td>-</td>
<td>0.0054</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>0.0518**</td>
</tr>
<tr>
<td>CO2</td>
<td>ppmvd</td>
<td>124,320</td>
<td>140</td>
<td>169,573</td>
<td>28,497</td>
<td>371</td>
<td></td>
<td>117**</td>
</tr>
</tbody>
</table>

*Conservatively assumed all PM(F) equals PM10(F) and PM2.5(F).

**Emission factors in lb/MMBtu

*** This represents average heat input during a startup/shutdown/upset event and the flare pilot flame.

All of the equipment specifications for the core plant are either from the vendor information or engineering estimate. Example emissions calculations for a representative set of units are provided below (tables show rounded values).

(a) PM10 (filterable+condensable) from the reformer stack.

\[
PM10(F + C) = \left(305,347 \frac{dscf}{min}\right) * \frac{(0.00308 + 0.00407) \frac{gr}{dscf}}{7,000 \frac{gr}{lb}} * 60 \frac{min}{hour} = 18.71 \frac{lb}{hour}
\]

\[
PM10(F + C) = 18.71 \frac{lb}{hour} * \frac{8,760 \frac{hour}{year}}{2,000 \frac{lb}{ton}} = 81.96 \frac{tons}{year}
\]

(b) NOx emissions from the reformer stack.

\[
NOx = \frac{45.52 [ppm]}{10^6} * 305,347 \frac{scf}{min} * 60 \frac{min}{hour} * \frac{46.1[lbmole]}{385.4 \frac{scf}{lbmole}} = 99.75 \frac{lb}{hour}
\]

\[
NOx = 99.75 \frac{lb}{hour} * \frac{8,760 \frac{hour}{year}}{2,000 \frac{lb}{ton}} = 436.89 \frac{tons}{year}
\]

(c) PM10 emissions from briquette cooling vent.

\[
PM10(F + C) = 58,111 \frac{dscf}{min} * \frac{0.0076 \frac{gr, PM10}{dscf}}{7,000 \frac{gr}{lb}} * 60 \frac{min}{hour} = 3.80 \frac{lb}{hour}
\]
\[ PM10(F+C) = 3.80 \left( \frac{\text{lb}}{\text{hour}} \right) \times \frac{8,760 \left( \frac{\text{hour}}{\text{year}} \right)}{2,000 \left( \frac{\text{lb}}{\text{ton}} \right)} = 16.64 \left( \frac{\text{tons}}{\text{year}} \right) \]

Emissions calculations for short-term (for modeling purposes) and annual emissions from the HBI Core Plant processes are provided in Appendix C and summarized in Table 3-2 and Table 3-3 below.

### Table 3-2. Short Term PTE for the HBI Core Plant

<table>
<thead>
<tr>
<th>Emission Point</th>
<th>Description</th>
<th>Emissions (lb/hour)</th>
<th>Emissions (tons/year)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>PM10 (F+C)</td>
<td>PM2.5 (F+C)</td>
</tr>
<tr>
<td>TR-28</td>
<td>Charge Hopper Scrubber</td>
<td>0.1</td>
<td>0.1</td>
</tr>
<tr>
<td>P-1</td>
<td>Bottom Seal Gas Exhaust</td>
<td>2.61</td>
<td>2.61</td>
</tr>
<tr>
<td>P-2</td>
<td>Reformer Exhaust</td>
<td>18.71</td>
<td>18.71</td>
</tr>
<tr>
<td>P-3</td>
<td>Hot Briquette Exhaust</td>
<td>4.1</td>
<td>4.1</td>
</tr>
<tr>
<td>P-4</td>
<td>Briquette Cooling Vent</td>
<td>3.8</td>
<td>3.8</td>
</tr>
<tr>
<td>P-5</td>
<td>Degasser Exhaust</td>
<td></td>
<td></td>
</tr>
<tr>
<td>P-6</td>
<td>Flare (Pilot only)*</td>
<td>0.005</td>
<td>0.005</td>
</tr>
</tbody>
</table>

*Due to the intermittent nature of flaring events during process upsets, startups, and shutdowns, consistent with the OEPA policy as noted in the modeling protocol and response, emissions during these events were not included for the short term standards.

### Table 3-3. Annual PTE for the HBI Core Plant

<table>
<thead>
<tr>
<th>Emission Point</th>
<th>Description</th>
<th>Emissions (tons/year)</th>
<th>Emissions (ton/year)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>PM (F)</td>
<td>PM10 (F+C)</td>
</tr>
<tr>
<td>TR-28</td>
<td>Charge Hopper Scrubber</td>
<td>0.44</td>
<td>0.44</td>
</tr>
<tr>
<td>P-1</td>
<td>Bottom Seal Gas Exhaust</td>
<td>11.21</td>
<td>11.44</td>
</tr>
<tr>
<td>P-2</td>
<td>Reformer Exhaust</td>
<td>35.30</td>
<td>81.96</td>
</tr>
<tr>
<td>P-3</td>
<td>Hot Briquette Exhaust</td>
<td>17.39</td>
<td>17.96</td>
</tr>
<tr>
<td>P-4</td>
<td>Briquette Cooling Vent</td>
<td>16.64</td>
<td>16.64</td>
</tr>
<tr>
<td>P-5</td>
<td>Degasser Exhaust</td>
<td></td>
<td></td>
</tr>
<tr>
<td>P-6a</td>
<td>Flare (SU/SD/Upset)</td>
<td>0.16</td>
<td>0.64</td>
</tr>
<tr>
<td>P-6b</td>
<td>Flare (Pilot)</td>
<td>0.01</td>
<td>0.02</td>
</tr>
</tbody>
</table>

In addition to the HBI Core Plant equipment noted above, there will be other ancillary equipment at the Core Plant that will support the production of HBI. These will include a cooling tower (with four cells) and emergency equipment. The proposed emergency fire water booster pump and emergency generator will be limited to no greater than 500 hour per year including duration of operation for testing and maintenance. Table 3-4 presents the key parameters for estimating PTE of ancillary equipment in the proposed HBI Core Plant.
Table 3-4. Key Parameters for Estimating PTE for the Ancillary Equipment in the HBI Core Plant

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Units</th>
<th>Cooling Tower</th>
<th>Emergency Fire Water Booster</th>
<th>Emergency Generator</th>
</tr>
</thead>
<tbody>
<tr>
<td>Recirculation Flow rate</td>
<td>gal/min</td>
<td>24,766</td>
<td>1.93</td>
<td>16.70</td>
</tr>
<tr>
<td>TDS</td>
<td>ppm</td>
<td>1,100</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fuel use</td>
<td>MMBtu/hr</td>
<td></td>
<td>1.93</td>
<td>16.70</td>
</tr>
<tr>
<td>Power</td>
<td>bhp</td>
<td>250</td>
<td>2,682</td>
<td></td>
</tr>
<tr>
<td>PM (F)</td>
<td>g/kW-hr</td>
<td>0.2</td>
<td>0.2</td>
<td></td>
</tr>
<tr>
<td>PM10 (F+C)</td>
<td>g/kW-hr</td>
<td>0.23</td>
<td>0.22</td>
<td></td>
</tr>
<tr>
<td>PM2.5 (F+C)</td>
<td>g/kW-hr</td>
<td>0.23</td>
<td>0.22</td>
<td></td>
</tr>
<tr>
<td>NOx</td>
<td>g/kW-hr</td>
<td>4.0</td>
<td>6.4</td>
<td></td>
</tr>
<tr>
<td>SO2</td>
<td>g/kW-hr</td>
<td>0.005</td>
<td>0.004</td>
<td></td>
</tr>
<tr>
<td>CO</td>
<td>g/kW-hr</td>
<td>3.5</td>
<td>3.5</td>
<td></td>
</tr>
<tr>
<td>VOC</td>
<td>lb/hp-hr</td>
<td>0.0025</td>
<td>0.0025</td>
<td></td>
</tr>
<tr>
<td>CO2</td>
<td>lb/MMBtu</td>
<td>163.05</td>
<td>163.05</td>
<td></td>
</tr>
<tr>
<td>CO2e</td>
<td>lb/MMBtu</td>
<td>163.61</td>
<td>163.61</td>
<td></td>
</tr>
<tr>
<td>Drift loss</td>
<td></td>
<td>0.0005%</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

The proposed RICE unit for the fire water booster will be a certified unit as required in 40 CFR §60.4205(c) and subject to the emissions standards in Table 4 of 40 CFR 60 Subpart IIII for NOx, CO, and PM. The proposed RICE unit for the emergency generator will also be a certified unit as required in 40 CFR §§60.4202(a)(2) and 60.4205(b) and subject to the emissions standards in 40 CFR §89.112 for NOx, CO, and PM for units that are larger than 560 kW. For emissions calculations, NSPS limitations for NOx and CO are used. The PM emissions rate is increased from 0.2 g/kW-hour to account for condensable emissions. SO2 emissions were calculated assuming 0.0015% sulfur in diesel fuel (15 ppm). Other emission factors are from AP-42 and 40 CFR Part 98. Example calculation for NOx and CO2 emissions from the emergency fire water booster engine are presented below.

\[
NOx = \frac{4.0 \left[ \frac{g}{kW \cdot h} \right]}{453.59 \left[ \frac{g}{lb} \right]} \times 186[kW] = 1.64 \left[ \frac{lb}{hour} \right]
\]

\[
NOx = 1.64 \left[ \frac{lb}{hour} \right] \times \frac{500 \left[ \frac{hour}{year} \right]}{2,000 \left[ \frac{lb}{ton} \right]} = 0.41 \left[ \frac{tons}{year} \right]
\]

\[
CO2 = 163.05 \left[ \frac{lb}{MMBtu} \right] \times 1.93 \left[ \frac{MMBtu}{hour} \right] = 315 \left[ \frac{lb}{hour} \right]
\]

\[
CO2 = 315 \left[ \frac{lb}{hour} \right] \times \frac{500 \left[ \frac{hour}{year} \right]}{2,000 \left[ \frac{lb}{ton} \right]} = 79 \left[ \frac{tons}{year} \right]
\]

The proposed RICE unit for the fire water booster engine is certified in accordance with 40 CFR §60.4205(c) and is subject to the emissions standards listed in Table 4 of 40 CFR 60 Subpart IIII for NOx, CO, and PM. The proposed RICE unit for the emergency generator is also certified in accordance with 40 CFR §§60.4202(a)(2) and 60.4205(b) and is subject to the emissions standards listed in 40 CFR §89.112 for NOx, CO, and PM for units that are larger than 560 kW. For emissions calculations, NSPS limitations for NOx and CO are used. The PM emission rate is increased from 0.2 g/kW-hour to account for condensable emissions. SO2 emissions were calculated assuming 0.0015% sulfur in diesel fuel (15 ppm). Other emission factors are from AP-42 and 40 CFR Part 98. Example calculation for NOx and CO2 emissions from the emergency fire water booster engine are presented below.

\[
NOx = \frac{4.0 \left[ \frac{g}{kW \cdot h} \right]}{453.59 \left[ \frac{g}{lb} \right]} \times 186[kW] = 1.64 \left[ \frac{lb}{hour} \right]
\]

\[
NOx = 1.64 \left[ \frac{lb}{hour} \right] \times \frac{500 \left[ \frac{hour}{year} \right]}{2,000 \left[ \frac{lb}{ton} \right]} = 0.41 \left[ \frac{tons}{year} \right]
\]

\[
CO2 = 163.05 \left[ \frac{lb}{MMBtu} \right] \times 1.93 \left[ \frac{MMBtu}{hour} \right] = 315 \left[ \frac{lb}{hour} \right]
\]

\[
CO2 = 315 \left[ \frac{lb}{hour} \right] \times \frac{500 \left[ \frac{hour}{year} \right]}{2,000 \left[ \frac{lb}{ton} \right]} = 79 \left[ \frac{tons}{year} \right]
\]
\[ E = k \times Q \times 60 \left( \frac{\text{min}}{\text{hour}} \right) \times 8.345 \left( \frac{\text{lb}H2O}{\text{gallon}} \right) \times \left[ \frac{\text{CTDS}}{10^6} \right] \times \left[ \frac{\text{DL}}{100} \right] \]

Where,

\( E \) = Particulate matter emissions, pounds per hour
\( Q \) = Circulating water flow rate, gallons per minute
CTDS = Circulating water total dissolved solids, ppm
DL = Drift loss, %
\( k \) = Particle size multiplier, PM=1, PM10=0.3150, PM2.5=0.1890

Example calculation for PM10 emissions from the cooling tower is provided below.

\[ PM10 = 0.315 \times 24,766 \left( \frac{\text{gal}}{\text{min}} \right) \times 60 \left( \frac{\text{min}}{\text{hour}} \right) \times 8.345 \left( \frac{\text{lb}H2O}{\text{gallon}} \right) \times \left[ \frac{1,100}{10^6} \right] \times \left[ \frac{0.0005}{100} \right] \]
\[ = 0.02 \left( \frac{\text{lb}}{\text{hour}} \right) \]

Emissions calculations for short-term (for modeling purposes) and annual emissions from the ancillary equipment at the HBI Core Plant are provided in Appendix C and summarized in Table 3-5 and Table 3-6 below. Emissions from intermittent operation of the emergency equipment are not included in the modeling for the short-term standards.

**Table 3-5. Short Term PTE for the Ancillary Equipment at HBI Core Plant**

<table>
<thead>
<tr>
<th>Emission Point</th>
<th>Description</th>
<th>Emissions (lb/hour)</th>
</tr>
</thead>
<tbody>
<tr>
<td>P-7</td>
<td>Cooling Tower</td>
<td>PM10 (F+C) 0.02</td>
</tr>
<tr>
<td></td>
<td></td>
<td>PM2.5 (F+C) 0.01</td>
</tr>
</tbody>
</table>

**Table 3-6. Annual PTE for the Ancillary Equipment at HBI Core Plant**

<table>
<thead>
<tr>
<th>Emission Point</th>
<th>Description</th>
<th>Emissions (tons/year)</th>
</tr>
</thead>
<tbody>
<tr>
<td>P-7</td>
<td>Cooling Tower</td>
<td>PM (F) 0.30</td>
</tr>
<tr>
<td></td>
<td></td>
<td>PM10 (F+C) 0.09</td>
</tr>
<tr>
<td></td>
<td></td>
<td>PM2.5 (F+C) 0.06</td>
</tr>
<tr>
<td>P-8</td>
<td>Emergency Diesel Fire Pump</td>
<td>NOx 0.41</td>
</tr>
<tr>
<td></td>
<td></td>
<td>SO2 &lt;1.0</td>
</tr>
<tr>
<td></td>
<td></td>
<td>CO 0.36</td>
</tr>
<tr>
<td></td>
<td></td>
<td>VOC 0.16</td>
</tr>
<tr>
<td></td>
<td></td>
<td>CO2 79</td>
</tr>
<tr>
<td></td>
<td></td>
<td>CO2e 79</td>
</tr>
<tr>
<td>P-9</td>
<td>Emergency Diesel Generator</td>
<td>0.22</td>
</tr>
<tr>
<td></td>
<td></td>
<td>0.25</td>
</tr>
<tr>
<td></td>
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<td>0.25</td>
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<td></td>
<td></td>
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<td></td>
<td></td>
<td>681</td>
</tr>
<tr>
<td></td>
<td></td>
<td>683</td>
</tr>
</tbody>
</table>

3.1.2 Oxide Handling and Storage Emissions

Various equipment and activities in the oxide handling and storage operations will result in particulate matter emissions, in the form of PM, PM10, and PM2.5. This section presents the

\(^5\) PM10 and PM2.5 emission factors from the TSD for APS Ocotillo Permit No.V95-007, PSD16-01, March 22, 2016, Maricopa County AQD. Maricopa County uses the PM10 factor of 0.315 for the majority of power plants in the County (this factor was developed based on the tests performed at the Gila Bend Power Plant). Maricopa County used the PM2.5 factor as 0.6 of PM10 based on the PSD permitting for Hydrogen Energy California by San Joaquin Valley Air Pollution Control District based on the data from the California Emission Inventory Development and Reporting System database.
operating parameters and emissions rates from these operations at the HBI Facility. Detailed emissions calculations are provided in Appendix C. The oxide handling operations at the Midwest Terminal facility\(^6\) are also presented in Appendix C and included as part of the secondary emissions for the project.

### 3.1.2.1 Oxide Handling and Storage Enclosed Transfer Points (Point)

As noted in section 2.4, the oxide is received at the Midwest Terminal facility and transferred to the Project site. The material will be transferred using the belt conveyors to the storage pile and from the storage pile to the lumps screen and day bins. The belt conveyors will also transfer oxides from day bins to screens and to the HBI Core Plant. All of the belt conveyor transfer points will be enclosed and exhausted to the baghouses to control particulate matter emissions. Table 3-7 presents the key parameters and estimated PTE for the oxide handling enclosed transfer points.

**Table 3-7. Key Parameters and Estimated PTE for Oxide Handling Enclosed Transfer Points with Enclosures and Baghouses**

<table>
<thead>
<tr>
<th>Emission Point</th>
<th>Description</th>
<th>Exhaust Flow ( \text{(dscfm)} )</th>
<th>PM Grain Loading ( \text{(gr/dscf)} )</th>
<th>PM/PM10/PM2.5** ( \text{(lb/hour)} )</th>
<th>( \text{(tons/year)} )</th>
</tr>
</thead>
<tbody>
<tr>
<td>TR-1</td>
<td>Transfer Tower-I Oxide from Midwest Conveyor to Stacker Conveyor</td>
<td>5,003</td>
<td>0.0025</td>
<td>0.11</td>
<td>0.12</td>
</tr>
<tr>
<td>TR-6</td>
<td>Transfer Tower-II Oxide Conveyor from Reclain Machine to Conveyor Transfer</td>
<td>2,779</td>
<td>0.0025</td>
<td>0.06</td>
<td>0.18</td>
</tr>
<tr>
<td>TR-7</td>
<td>Transfer Tower-III Oxide Conveyor from to Conveyor Transfer</td>
<td>2,779</td>
<td>0.0025</td>
<td>0.06</td>
<td>0.18</td>
</tr>
<tr>
<td>TR-10</td>
<td>Oxide Storage Day Bins Vents</td>
<td>20,011</td>
<td>0.0025</td>
<td>0.43</td>
<td>1.80</td>
</tr>
<tr>
<td>SR-1</td>
<td>Oxide Screens</td>
<td>23,762</td>
<td>0.0025</td>
<td>0.51</td>
<td>2.14</td>
</tr>
<tr>
<td>TR-13</td>
<td>Oxide Transfer from Conveyor to Bucket Elevator</td>
<td>2,779</td>
<td>0.0025</td>
<td>0.06</td>
<td>0.25</td>
</tr>
<tr>
<td>TR-14</td>
<td>Coating Storage and Mixing and Fines Transfer</td>
<td>5,003</td>
<td>0.003</td>
<td>0.11</td>
<td>0.47</td>
</tr>
</tbody>
</table>

Example calculations for particulate matter emissions from TR-1 are provided below. Note, flow rate is increased by 10% from design flow in order to be conservative in terms of PTE.

\[
PM10 = 5,003 \text{[dscfm]} \times \frac{0.0025 \text{[gr,PM10/dscf]} }{7,000 \text{[gr/lb]}} \times 60 \text{[min/hour]} = 0.11 \text{[lb/hour]}
\]

Annual emissions are calculated using the expected hours of operation to transfer the amount of oxide projected to be used in the process.

\[
PM10 = 0.11 \text{[lb/hour]} \times \frac{2,172 \text{[hour/year]}}{2,000 \text{[lb/ton]}} = 0.12 \text{[tons/year]}
\]

### 3.1.2.2 Oxide Handling Transfer Points (Fugitive)

Fugitive emissions will occur from transfer of materials at various transfer points. These transfer points are related to oxide stacking and reclaiming at the stockpile and transfer of oxide lumps, fines, and REMET to stockpiles and hoppers. Where practicable, IU is proposing to use add-on

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\(^6\) Midwest Terminals is a separately owned facility that is not under the common control of IU.
controls or enclosures to minimize dust. Table 3-8 and Table 3-9 present the key parameters and estimated PTE for the fugitive oxide handling transfer points.

### Table 3-8. Key Parameters for Oxide Handling Fugitive Transfer Points

<table>
<thead>
<tr>
<th>Emission Point</th>
<th>Description</th>
<th>Control Efficiency</th>
<th>Capacity or Rate (tons/hour)</th>
<th>Capacity or Rate (tons/year)</th>
</tr>
</thead>
<tbody>
<tr>
<td>TR-2</td>
<td>Conveyor to Stacker Conveyor</td>
<td>Windshield</td>
<td>3,310</td>
<td>3,594,666</td>
</tr>
<tr>
<td>TR-3</td>
<td>Oxide Stacker Conveyor to Stockpile</td>
<td>95%</td>
<td>3,310</td>
<td>3,594,666</td>
</tr>
<tr>
<td>TR-4</td>
<td>Oxide Reclaim Bucket Wheel to Conveyor</td>
<td>95%</td>
<td>1,220</td>
<td>3,594,666</td>
</tr>
<tr>
<td>TR-5</td>
<td>Oxide Conveyor from Reclaim to Conveyor</td>
<td>Windshield</td>
<td>1,220</td>
<td>3,594,666</td>
</tr>
<tr>
<td>TR-8</td>
<td>Lumps from Conveyor to Stockpile</td>
<td>95%</td>
<td>1.2</td>
<td>3,595</td>
</tr>
<tr>
<td>TR-9</td>
<td>Lumps from FEL to Trucks</td>
<td>None</td>
<td>28</td>
<td>3,595</td>
</tr>
<tr>
<td>TR-11</td>
<td>Oxide Fines to Stockpile</td>
<td>95%</td>
<td>24</td>
<td>71,893</td>
</tr>
<tr>
<td>TR-12</td>
<td>Oxide Fines from FEL to Truck</td>
<td>None</td>
<td>28</td>
<td>71,893</td>
</tr>
<tr>
<td>TR-15</td>
<td>REMET Conveyor to Stockpile</td>
<td>None</td>
<td>14</td>
<td>107,840</td>
</tr>
<tr>
<td>TR-16</td>
<td>REMET from FEL to Hopper</td>
<td>None</td>
<td>29</td>
<td>107,840</td>
</tr>
</tbody>
</table>

### Table 3-9. Estimated PTE for Oxide Handling Fugitive Transfer Points

<table>
<thead>
<tr>
<th>Emission Point</th>
<th>Description</th>
<th>PM</th>
<th>PM10</th>
<th>PM2.5</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>(lb/hr)</td>
<td>(ton/yr)</td>
<td>(lb/hr)</td>
</tr>
<tr>
<td>TR-2</td>
<td>Conveyor to Stacker Conveyor</td>
<td>0.71</td>
<td>0.38</td>
<td>0.33</td>
</tr>
<tr>
<td>TR-3</td>
<td>Oxide Stacker Conveyor to Stockpile</td>
<td>0.65</td>
<td>0.35</td>
<td>0.31</td>
</tr>
<tr>
<td>TR-4</td>
<td>Oxide Reclaim Bucket Wheel to Conveyor</td>
<td>0.24</td>
<td>0.35</td>
<td>0.11</td>
</tr>
<tr>
<td>TR-5</td>
<td>Oxide Conveyor Reclaim to Conveyor</td>
<td>0.26</td>
<td>0.38</td>
<td>0.12</td>
</tr>
<tr>
<td>TR-8</td>
<td>Lumps from Conveyor to Stockpile</td>
<td>0.0002</td>
<td>0.0004</td>
<td>0.0001</td>
</tr>
<tr>
<td>TR-9</td>
<td>Lumps from FEL to Trucks</td>
<td>0.11</td>
<td>0.0071</td>
<td>0.05</td>
</tr>
<tr>
<td>TR-11</td>
<td>Oxide Fines to Stockpile</td>
<td>0.01</td>
<td>0.01</td>
<td>0.005</td>
</tr>
<tr>
<td>TR-12</td>
<td>Oxide Fines from FEL to Truck</td>
<td>0.23</td>
<td>0.29</td>
<td>0.11</td>
</tr>
<tr>
<td>TR-15</td>
<td>REMET Conveyor to Stockpile</td>
<td>0.11</td>
<td>0.43</td>
<td>0.0537</td>
</tr>
<tr>
<td>TR-16</td>
<td>REMET from FEL to Hopper</td>
<td>0.24</td>
<td>0.43</td>
<td>0.11</td>
</tr>
</tbody>
</table>

Emissions from these transfer points are estimated using the equations in the AP-42 section 13.2.4, page 4. Example calculations for PM10 emissions from TR-3 are provided below. For this calculation, wind speed of 9.4 mph and oxide moisture content of 2.5% (oxide and lumps) are used in the equation. 95% control efficiency water or chemical suppressants as needed is applied.

\[
PM10 = 0.35 * 0.0032 * \left( \frac{9.4\text{[mph]}}{5} \right)^{1.3} = 0.004 \left[ \frac{\text{lb}}{\text{ton}} \right]
\]

\[
PM10 = 0.004 \left[ \frac{\text{lb}}{\text{ton}} \right] * 3,310 \left[ \frac{\text{tons}}{\text{hour}} \right] * (1 - 95%) = 0.65 \left[ \frac{\text{lb}}{\text{hour}} \right]
\]

---

\footnote{U.S. EPA's Compilation of Air Pollutant Emission Factors, AP-42, Volume 1: Stationary Point and Area Sources, Section 13.2.4, Aggregate Handling and Storage Piles, November 2006.}
Example calculations for PM10 emissions from TR-9 are provided below. For this calculation, wind speed of 1 mph is used in the equation as the equipment will be located in a three sided windshield to minimize wind speed.

\[
PM10 = 0.35 \times 0.0032 \times \left( \frac{9.4 \text{ mph}}{5} \right)^{1.3} \times \left( \frac{2.5}{2} \right)^{1.4} = 0.00186 \text{ [lb/ton]}
\]

\[
PM10 = 0.00186 \text{ [lb/ton]} \times 28 \text{ [tons/hour]} = 0.05 \text{ [lb/hour]}
\]

\[
PM10 = 0.00186 \text{ [lb/ton]} \times \frac{3,595 \text{ [tons/year]}}{2000 \text{ [lb/ton]}} = 0.0033 \text{ [tons/year]}
\]

### 3.1.2.1 Oxide Materials Stockpile (Fugitive)

Fugitive emissions will occur from wind erosion from the stockpiles of oxide materials at the site. There will be four stockpiles: oxide, oxide-lumps, oxide-fines, and REMET. Where practicable, IU is proposing to use add-on controls to minimize dust. Table 3-10 and Table 3-11 presents the key parameters and estimated PTE for wind erosion from the oxide material stockpiles.

#### Table 3-10. Key Parameters for Oxide Materials Stockpiles

<table>
<thead>
<tr>
<th>Emission Point</th>
<th>Description</th>
<th>Control Efficiency</th>
<th>Storage (tons)</th>
<th>Area (acres)</th>
</tr>
</thead>
<tbody>
<tr>
<td>WE-1</td>
<td>Two (2) Oxide Stockpiles</td>
<td>99%</td>
<td>772,000 (total)</td>
<td>17.12 (total)</td>
</tr>
<tr>
<td>WE-2</td>
<td>Oxide Lumps Stockpile</td>
<td>99%</td>
<td>1,200</td>
<td>0.07</td>
</tr>
<tr>
<td>WE-3</td>
<td>Oxide Fines Stockpile</td>
<td>99%</td>
<td>5,600</td>
<td>0.27</td>
</tr>
<tr>
<td>WE-4</td>
<td>REMET Stockpile</td>
<td>30%</td>
<td>6,700</td>
<td>0.21</td>
</tr>
</tbody>
</table>

#### Table 3-11. Estimated PTE for Oxide Materials Stockpiles

<table>
<thead>
<tr>
<th>Emission Point</th>
<th>Description</th>
<th>PM (lb/hr)</th>
<th>PM10 (ton/yr)</th>
<th>PM2.5 (lb/hr)</th>
<th>PM2.5 (ton/yr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>WE-1</td>
<td>Two (2) Oxide Stockpile</td>
<td>0.09</td>
<td>0.04</td>
<td>0.10</td>
<td>0.02</td>
</tr>
<tr>
<td>WE-2</td>
<td>Oxide Lumps Stockpile</td>
<td>0.0002</td>
<td>0.0001</td>
<td>0.0001</td>
<td>0.0001</td>
</tr>
<tr>
<td>WE-3</td>
<td>Oxide Fines Stockpile</td>
<td>0.001</td>
<td>0.003</td>
<td>0.0007</td>
<td>0.002</td>
</tr>
<tr>
<td>WE-4</td>
<td>REMET Stockpile</td>
<td>0.08</td>
<td>0.038</td>
<td>0.08</td>
<td>0.015</td>
</tr>
</tbody>
</table>

Emissions from the raw material stockpiles are estimated using the equation in the AWMA Engineering Manual for stockpile emissions.\(^8\) Example calculations for PM10 emissions from

---

WE-1 are provided below. For this calculation, silt content of 3.4% and the duration of threshold wind speed as 23% are used in the equation.\(^9\) Other inputs to the equations are provided in Appendix C. 99% control efficiency is applied for the use of chemical stabilization or watering.

\[
PM10 = 1.7 \times \left( \frac{3.4}{1.5} \right) \times \left( \frac{365 - 120}{235} \right) \times \left( \frac{23}{15} \right) \times 0.5 = 3.1 \text{ lb/day per acre}
\]

\[
PM10 = 3.1 \left[ \frac{lb}{day \text{ per acre}} \right] \times \frac{17.12 \text{ [acre]}}{24} \times 2 \times (1 - 99%) = 0.04 \left[ \frac{lb}{hour} \right]
\]

Conservatively, the maximum hourly rate is calculated by doubling the daily rate divided by 24 hours per day.

\[
PM10 = 3.1 \left[ \frac{lb}{day \text{ per acre}} \right] \times 365 \left[ \frac{days}{year} \right] \times \frac{17.12 \text{ [acre]}}{2000 \text{ [lb/ton]}} \times (1 - 99%) = 0.10 \left[ \frac{tons}{year} \right]
\]

### 3.1.2.1 Fugitive Emissions from Front End Loaders and Trucks Movement

Fugitive emissions will occur from the movement of front end loaders (“FEL”) over unpaved surfaces and trucks over paved roads. FEL and trucks will be used for transporting oxide-lumps, oxide-fines, and REMET. Table 3-12 and Table 3-13 present the key parameters and estimated PTE for the fugitives from FEL and trucks traffic.

#### Table 3-12. Key Parameters for Unpaved Surfaces and Paved Roads

<table>
<thead>
<tr>
<th>Emission Point</th>
<th>Description</th>
<th>Control Efficiency</th>
<th>Throughput (tons/hour)</th>
<th>Throughput (tons/year)</th>
</tr>
</thead>
<tbody>
<tr>
<td>FEL-1</td>
<td>FEL for Oxide Lumps (Unpaved)</td>
<td>95%</td>
<td>28</td>
<td>3,595</td>
</tr>
<tr>
<td>HR-1</td>
<td>Trucks for Oxide Lumps (Paved)</td>
<td>95%</td>
<td>28</td>
<td>3,595</td>
</tr>
<tr>
<td>FEL-2</td>
<td>FEL for Oxide Fines (Unpaved)</td>
<td>95%</td>
<td>28</td>
<td>71,893</td>
</tr>
<tr>
<td>HR-2</td>
<td>Trucks for Oxide Fines (Paved)</td>
<td>95%</td>
<td>28</td>
<td>71,893</td>
</tr>
<tr>
<td>HR-3</td>
<td>Trucks for Oxide Coating (Paved)</td>
<td>95%</td>
<td>28</td>
<td>8,987</td>
</tr>
<tr>
<td>FEL-3</td>
<td>FEL for REMET (Unpaved)</td>
<td>95%</td>
<td>29</td>
<td>107,840</td>
</tr>
</tbody>
</table>

#### Table 3-13. Estimated PTE for Unpaved Surfaces and Paved Roads

<table>
<thead>
<tr>
<th>Emission Point</th>
<th>Description</th>
<th>(PM)</th>
<th>(PM10)</th>
<th>(PM2.5)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>(\text{lb/hr})</td>
<td>(\text{ton/yr})</td>
<td>(\text{lb/hr})</td>
</tr>
<tr>
<td>FEL-1</td>
<td>FEL for Oxide Lumps (Unpaved)</td>
<td>0.02</td>
<td>0.0007</td>
<td>0.004</td>
</tr>
<tr>
<td>HR-1</td>
<td>Trucks for Oxide Lumps (Paved)</td>
<td>0.01</td>
<td>0.0006</td>
<td>0.002</td>
</tr>
<tr>
<td>FEL-2</td>
<td>FEL for Oxide Fines (Unpaved)</td>
<td>0.02</td>
<td>0.01</td>
<td>0.004</td>
</tr>
<tr>
<td>HR-2</td>
<td>Trucks for Oxide Fines (Paved)</td>
<td>0.15</td>
<td>0.18</td>
<td>0.03</td>
</tr>
<tr>
<td>HR-3</td>
<td>Trucks for Oxide Coating (Paved)</td>
<td>0.16</td>
<td>0.02</td>
<td>0.032</td>
</tr>
<tr>
<td>FEL-3</td>
<td>FEL for REMET (Unpaved)</td>
<td>0.34</td>
<td>0.42</td>
<td>0.08</td>
</tr>
</tbody>
</table>

Emissions from the FEL movement on unpaved surfaces and the trucks travel on paved roads are estimated using the methodology in AP-42 Chapters 13.2.2 and 13.2.1.\(^{10}\) Example calculations for PM10 emissions from FEL-3 are provided below. For this calculation, average vehicle weight of 66 tons and silt content of 3.4% is used in the equation. Other inputs to the equations are provided in Appendix C. 95% control efficiency is applied for the use of chemical stabilization of unpaved surfaces.

---

\(^9\) Duration of threshold wind speed is the percent of time the unobstructed wind speed exceeds 12 mph at the pile height.

PM10 = 1.5 * \left(\frac{3.4}{12}\right)^{0.9} \cdot \left(\frac{66}{3}\right)^{0.45} = 1.94 \left[\frac{lb \ (hourly)}{VMT}\right]

No credit for natural precipitation is taken for hourly emissions estimate here.

PM10 = 1.94 \left[\frac{lb \ (hourly)}{VMT}\right] \cdot 0.833 \left[\frac{VMT}{hour}\right] \cdot (1 - 95\%) = 0.08 \left[\frac{lb \ (hourly)}{hour}\right]

PM10 = 1.5 * \left(\frac{3.4}{12}\right)^{0.9} \cdot \left(\frac{66}{3}\right)^{0.45} \cdot \left(\frac{365 - 120}{365}\right) = 1.30 \left[\frac{lb \ (yearly)}{VMT}\right]

PM10 = 1.30 \left[\frac{lb \ (yearly)}{VMT}\right] / 2000 \left[\frac{lb \ (ton)}{year}\right] \cdot 3,057 \left[\frac{VMT}{ton}\right] \cdot (1 - 95\%) = 0.10 \left[\frac{tons \ (year)}{year}\right]

Example calculations for PM10 emissions from HR-2 are provided below. For this calculation, average vehicle weight of 29 tons and silt loading of 9.7 g/m² is used in the equation. Other inputs to the equations are provided in Appendix C. 95% control efficiency is applied for the use of watering and sweeping of paved surfaces.

PM10 = 0.0022 \cdot 9.7^{0.91} \cdot 29^{1.02} = 0.54 \left[\frac{lb \ (hourly)}{VMT}\right]

No credit for natural precipitation is taken for hourly emissions estimate.

PM10 = 0.54 \left[\frac{lb \ (hourly)}{VMT}\right] \cdot 1.1 \left[\frac{VMT}{hour}\right] \cdot (1 - 95\%) = 0.03 \left[\frac{lb \ (hour)}{hour}\right]

PM10 = 0.0022 \cdot 9.7^{0.91} \cdot 29^{1.02} \cdot \left(1 - \frac{120}{4 \cdot 365}\right) = 0.50 \left[\frac{lb \ (yearly)}{VMT}\right]

PM10 = 0.50 \left[\frac{lb \ (yearly)}{VMT}\right] / 2000 \left[\frac{lb \ (ton)}{year}\right] \cdot 2,918 \left[\frac{VMT}{ton}\right] \cdot (1 - 95\%) = 0.04 \left[\frac{tons \ (year)}{year}\right]

3.1.3 HBI Handling and Storage Emissions

Various equipment and activities in the HBI handling and storage operations will also result in particulate matter emissions, in the form of PM, PM10, and PM2.5. This section presents the operating parameters and emissions rates from these operations at the HBI Facility. Detailed emissions calculations are provided in Appendix C.

3.1.3.1 HBI Handling and Storage Enclosed Transfer Points (Point)

HBI is transferred from the HBI Core Plant briquetting machines to the HBI stockpile using a system of conveyors and transfer towers. All of the HBI conveyor transfer points will be enclosed and exhausted to venturi scrubbers to control particulate matter emissions. Table 3-14 presents the key parameters and estimated PTE for the HBI handling enclosed transfer points.

Table 3-14. Key Parameters and Estimated PTE for HBI Handling Enclosed Transfer Points with Enclosures and Venturi Scrubbers

<table>
<thead>
<tr>
<th>Emission Point</th>
<th>Description</th>
<th>Exhaust Volume* (dscfm)</th>
<th>PM Grain Loading (gr/dscf)</th>
<th>PM/PM10/PM2.5** (lb/hour)</th>
<th>(tons/year)</th>
</tr>
</thead>
<tbody>
<tr>
<td>TR-17</td>
<td>HBI Conveyor Transfer Tower-I</td>
<td>4.516</td>
<td>0.0025</td>
<td>0.10</td>
<td>0.37</td>
</tr>
<tr>
<td>TR-18</td>
<td>HBI Conveyor Transfer Tower-II &amp; III</td>
<td>4.516</td>
<td>0.0025</td>
<td>0.10</td>
<td>0.37</td>
</tr>
<tr>
<td>TR-23</td>
<td>HBI Conveyors Transfer Tower to Loadout</td>
<td>2.779</td>
<td>0.0025</td>
<td>0.06</td>
<td>0.20</td>
</tr>
<tr>
<td>TR-24</td>
<td>HBI Loadout Bin and Conveyor</td>
<td>2.779</td>
<td>0.0025</td>
<td>0.06</td>
<td>0.20</td>
</tr>
<tr>
<td>TR-25</td>
<td>HBI Truck Loadout Building Exhaust</td>
<td>4.169</td>
<td>0.0025</td>
<td>0.10</td>
<td>0.22</td>
</tr>
</tbody>
</table>

*Exhaust volume is scaled up by 10% to account for worst case emission rates.
Calculation methodology for the HBI transfer points is similar to the one used for the enclosed oxide handling processes controlled by baghouses in 3.1.2.1.

### 3.1.3.2 HBI Handling Transfer Points (Fugitive)

Fugitive emissions will occur from the transfers of HBI at various transfer points. These transfer points are related to HBI stacking and reclaiming at the stockpile. Where practicable, IU is proposing to use add-on controls or enclosures to minimize dust. Table 3-8 and Table 3-9 present the key parameters and estimated PTE for the fugitive HBI handling transfer points.

**Table 3-15. Key Parameters for HBI Handling Fugitive Transfer Points**

<table>
<thead>
<tr>
<th>Emission Point</th>
<th>Description</th>
<th>Control Efficiency</th>
<th>Capacity or Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Windshield</td>
<td>(tons/hour)</td>
</tr>
<tr>
<td>TR-19</td>
<td>HBI Conveyor to Stacker</td>
<td>320</td>
<td>2,479,080</td>
</tr>
<tr>
<td>TR-20</td>
<td>HBI Stacker to Stockpile</td>
<td>95%</td>
<td>320</td>
</tr>
<tr>
<td>TR-21</td>
<td>FEL Drop to Hopper</td>
<td>566</td>
<td>2,479,080</td>
</tr>
<tr>
<td>TR-22</td>
<td>HBI Hopper to Conveyor</td>
<td>566</td>
<td>2,479,080</td>
</tr>
<tr>
<td>TR-26</td>
<td>HBI Drop to Train</td>
<td>566</td>
<td>2,479,080</td>
</tr>
<tr>
<td>TR-27</td>
<td>HBI Drop to Truck</td>
<td>170</td>
<td>743,724</td>
</tr>
</tbody>
</table>

* The truck loading operation and the rail car loading operation will occur inside buildings with limited openings for truck and train access.

**Table 3-16. Estimated PTE for HBI Handling Fugitive Transfer Points**

<table>
<thead>
<tr>
<th>Emission Point</th>
<th>Description</th>
<th>PM</th>
<th>PM10</th>
<th>PM2.5</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>(lb/hr)</td>
<td>(ton/yr)</td>
<td>(lb/hr)</td>
</tr>
<tr>
<td>TR-19</td>
<td>HBI Conveyor to Stacker</td>
<td>0.14</td>
<td>0.54</td>
<td>0.02</td>
</tr>
<tr>
<td>TR-25</td>
<td>HBI Stacker to Stockpile</td>
<td>0.23</td>
<td>0.88</td>
<td>0.04</td>
</tr>
<tr>
<td>TR-21</td>
<td>FEL Drop to Hopper</td>
<td>0.23</td>
<td>0.50</td>
<td>0.04</td>
</tr>
<tr>
<td>TR-22</td>
<td>HBI Hopper to Conveyor</td>
<td>0.25</td>
<td>0.54</td>
<td>0.04</td>
</tr>
<tr>
<td>TR-26</td>
<td>HBI Drop to Train</td>
<td>0.01</td>
<td>0.03</td>
<td>0.001</td>
</tr>
<tr>
<td>TR-27</td>
<td>HBI Drop to Truck</td>
<td>0.004</td>
<td>0.001</td>
<td>0.0003</td>
</tr>
</tbody>
</table>

Calculation methodology for the HBI handling fugitive transfer points is similar to the one used for the fugitive oxide handling processes in 3.1.2.2.

### 3.1.3.3 HBI Stockpile (Fugitive)

Fugitive emissions will occur from wind erosion from the HBI stockpile at the site. IU is proposing to use add-on controls to minimize dust. The stockpile will store 111,000 tons of HBI on a proposed area of 4.02 acres. For this calculation, silt content of 1.5% is used in the equation. Other inputs to the equations are provided in Appendix C. 99% control efficiency is applied for use of chemical stabilization or watering, as needed. Estimated PTE for HBI stockpile is provided in Table 3-17.

**Table 3-17. Estimated PTE for HBI Stockpiles**

<table>
<thead>
<tr>
<th>Emission Point</th>
<th>Description</th>
<th>PM</th>
<th>PM10</th>
<th>PM2.5</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>(lb/hr)</td>
<td>(ton/yr)</td>
<td>(lb/hr)</td>
</tr>
<tr>
<td>WE-5</td>
<td>HBI Stockpile</td>
<td>0.01</td>
<td>0.02</td>
<td>0.005</td>
</tr>
</tbody>
</table>

Emissions from the HBI stockpile are estimated using the methodology similar to the one used for the oxide materials stockpiles in 3.1.2.1.
### 3.1.3.4 Fugitive Emissions from Front End Loaders and Trucks Movement

Fugitive emissions will occur from movement of front end loaders (“FEL”) over unpaved surfaces and trucks over paved roads for HBI transfers. Table 3-18 and Table 3-19 present the key parameters and estimated PTE for the fugitives from FEL and trucks traffic for HBI transport.

**Table 3-18. Key Parameters for HBI Unpaved Surfaces and Paved Roads**

<table>
<thead>
<tr>
<th>Emission Point</th>
<th>Description</th>
<th>Control Efficiency</th>
<th>Throughput (tons/hour)</th>
<th>Throughput (tons/year)</th>
</tr>
</thead>
<tbody>
<tr>
<td>FEL-4</td>
<td>FEL for HBI (Unpaved)</td>
<td>95%</td>
<td>566</td>
<td>2,479,080</td>
</tr>
<tr>
<td>HR-4</td>
<td>Trucks for HBI (Paved)*</td>
<td>89%</td>
<td>170</td>
<td>743,724</td>
</tr>
</tbody>
</table>

* Transport of HBI by trucks is a backup operating scenario.

**Table 3-19. Estimated PTE for HBI Unpaved Surfaces and Paved Roads**

<table>
<thead>
<tr>
<th>Emission Point</th>
<th>Description</th>
<th>PM</th>
<th>PM10</th>
<th>PM2.5</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>(lb/hr)</td>
<td>(ton/yr)</td>
<td>(lb/hr)</td>
</tr>
<tr>
<td>FEL-4</td>
<td>FEL for HBI (Unpaved)</td>
<td>0.34</td>
<td>0.50</td>
<td>0.08</td>
</tr>
<tr>
<td>HR-4</td>
<td>Trucks for HBI (Paved)</td>
<td>1.69</td>
<td>2.94</td>
<td>0.34</td>
</tr>
</tbody>
</table>

Calculation methodology for the HBI transport by FEL and trucks is similar to the one used for the oxide transport by FEL and trucks in 3.1.2.1.

### 3.1.4 Miscellaneous Emitting Equipment

A small amount of VOC and GHG emissions from natural gas leaks from piping may occur from the miscellaneous equipment as described here. Fugitive emissions from valves in gas service, pressure relief valves, and connector components are estimated using the EPA’s 1995 guidelines for estimating emissions from equipment leaks.\(^1\) A VOC emissions factor was developed as the ratio of methane to VOCs using EPA’s background document for the proposed standards for oil and gas sector.\(^2\)

### 3.1.5 Summary of Project Potential to Emit

Table 3-20 summarizes PTE of regulated NSR pollutants for the HBI Facility. Detailed emissions calculations are provided in Appendix C.

---


## Table 3-20. Summary of PTE for the HBI Facility

<table>
<thead>
<tr>
<th>Emission Unit(s)/Groups</th>
<th>PM</th>
<th>PM10</th>
<th>PM2.5</th>
<th>NOx</th>
<th>SO₂</th>
<th>CO</th>
<th>VOC</th>
<th>CO₂</th>
<th>CO₂e</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oxide Storage and Handling</td>
<td>8.79</td>
<td>6.71</td>
<td>5.42</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Furnace Charge Hopper Scrubber</td>
<td>0.44</td>
<td>0.44</td>
<td>0.44</td>
<td>8.85</td>
<td>1.05</td>
<td>12.36</td>
<td>0.00</td>
<td>5,891</td>
<td>5,891</td>
</tr>
<tr>
<td>Bottom Seal Gas Scrubber</td>
<td>11.21</td>
<td>11.44</td>
<td>11.44</td>
<td>1.88</td>
<td>1.05</td>
<td>188.34</td>
<td>0.00</td>
<td>170</td>
<td>170</td>
</tr>
<tr>
<td>Refiner Exhaust</td>
<td>35.30</td>
<td>81.96</td>
<td>81.96</td>
<td>436.89</td>
<td>18.70</td>
<td>229.29</td>
<td>7.97</td>
<td>1,553,868</td>
<td>1,554,047</td>
</tr>
<tr>
<td>Hot Briquette Scrubber</td>
<td>17.39</td>
<td>17.96</td>
<td>17.96</td>
<td>17.25</td>
<td>0.79</td>
<td>9.07</td>
<td>0.00</td>
<td>54,071</td>
<td>54,071</td>
</tr>
<tr>
<td>Briquette Cooling System Vent</td>
<td>16.64</td>
<td>16.64</td>
<td>16.64</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Degasser Exhaust</td>
<td>106.24</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>1,105</td>
<td>1,105</td>
</tr>
<tr>
<td>Flare (Pilot Only)</td>
<td>0.17</td>
<td>0.66</td>
<td>0.66</td>
<td>6.03</td>
<td>0.05</td>
<td>27.49</td>
<td>4.59</td>
<td>10,375</td>
<td>10,386</td>
</tr>
<tr>
<td>HBI Storage and Handling</td>
<td>7.51</td>
<td>2.50</td>
<td>1.71</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cooling Tower</td>
<td>0.30</td>
<td>0.09</td>
<td>0.06</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>0.12</td>
<td></td>
</tr>
<tr>
<td>Emergency Fire Water Booster</td>
<td>0.02</td>
<td>0.02</td>
<td>0.02</td>
<td>0.41</td>
<td>0.00</td>
<td>0.36</td>
<td>0.16</td>
<td>79</td>
<td>79</td>
</tr>
<tr>
<td>Emergency Generator</td>
<td>0.22</td>
<td>0.25</td>
<td>0.25</td>
<td>7.05</td>
<td>0.01</td>
<td>3.86</td>
<td>0.43</td>
<td>681</td>
<td>683</td>
</tr>
<tr>
<td>Fugitive Emissions from Components</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>0.49</td>
<td>446</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>97.76</strong></td>
<td><strong>138.64</strong></td>
<td><strong>136.53</strong></td>
<td><strong>478.37</strong></td>
<td><strong>21.65</strong></td>
<td><strong>577.01</strong></td>
<td><strong>13.77</strong></td>
<td>1,626,240</td>
<td>1,626,878</td>
</tr>
<tr>
<td>PSD Significant Emissions Rate</td>
<td>25</td>
<td>15</td>
<td>10</td>
<td>40</td>
<td>40</td>
<td>100</td>
<td>40</td>
<td>-NA-</td>
<td>75,000</td>
</tr>
<tr>
<td>Whether Significant?</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>No</td>
<td>Yes</td>
<td>No</td>
<td>Yes</td>
<td></td>
</tr>
</tbody>
</table>
3.2 Hazardous Air Pollutants Emissions

The HAPs emissions from the proposed emissions units associated with the Project are presented in this section.

3.2.1 Natural Gas Combustion HAPs Emissions

Combustion of natural gas in the proposed emission units forms HAPs. However, natural gas-fired reformer generates relatively small HAPs emissions. HAPs emissions are calculated for the natural gas combustion in the reformer and flare pilot with maximum annual natural gas heat input as worst case. Table 3-21 presents the heat input calculations for the natural gas combustion units.

<table>
<thead>
<tr>
<th>Unit</th>
<th>Heat Input Calculations for Natural Gas Combustion Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reformer</td>
<td>MMBtu/hour: 337, MMscf/year: 2,898</td>
</tr>
<tr>
<td>Flare (NG Pilot)</td>
<td>MMBtu/hour: 0.7, MMscf/year: 6</td>
</tr>
</tbody>
</table>

The HAP emission factors are from the U.S. EPA's Compilation of Air Pollutant Emission Factors, AP-42, Volume 1: Stationary Point and Area Sources, Section 1.4, Natural Gas Combustion. Potential select HAP emissions and Total HAPs for the proposed natural gas units are detailed in Table 3-22.

<table>
<thead>
<tr>
<th>Unit</th>
<th>Emissions tons/year</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reformer</td>
<td>2.61</td>
</tr>
<tr>
<td>Flare (NG Pilot)</td>
<td>0.01</td>
</tr>
</tbody>
</table>

3.2.2 Cooling Systems HAPs Emissions

HAP emissions were calculated based on the cooling tower drift rates and the chemical composition of the cooling tower blowdown. It is conservatively assumed that the entire quantity of each chemical in the blowdown would be emitted. The concentration of HAPs in the blowdown for the system was provided by the project engineering support. Chloroform emissions for the cooling tower are based on factors from EPA’s “Locating and Estimating Air Emissions from Sources of Chloroform” (EPA 1984). Potential emissions of HAPs from the proposed cooling systems are presented in Table 3-23.

<table>
<thead>
<tr>
<th>Unit</th>
<th>Single HAP (Hexane)</th>
<th>Total HAP</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reformer</td>
<td>2.61</td>
<td>2.74</td>
</tr>
<tr>
<td>Flare (NG Pilot)</td>
<td>0.01</td>
<td>0.01</td>
</tr>
</tbody>
</table>

There is an error in the chloroform emission factor in the report. This noted in Appendix B of the “Bowie Power Station, Class I Permit Application,” September 2013, as “Personal communication with EPA by Russ Henning, Radian International. The chloroform emission factor for cooling towers from the L&E document should be 2.3/0.75 kg/E9 liters not E6 liters.”
3.2.3 Emergency RICE HAPs Emissions

Diesel fuel combustion in the RICE units for the fire water pump and the emergency generator will result in HAP emissions. The potential emissions of HAPs are summarized in Table 3-23. HAP emissions are based on emission factors from the U.S. EPA's Compilation of Air Pollutant Emission Factors, AP-42, 5th Edition, Tables 3.4-3 and 3.4-4.

3.2.4 Summary of Source-wide HAPs Emissions

Table 3-23 presents the HAPs emissions from the overall Project.

Table 3-23. Source-wide HAPs Emissions

<table>
<thead>
<tr>
<th>HAPs</th>
<th>Emissions (tons/year)</th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>NG Combustion</td>
<td>Cooling Sys.</td>
<td>Emergency RICE</td>
<td>Total</td>
</tr>
<tr>
<td>Chloroform</td>
<td>0.12</td>
<td></td>
<td>0.12</td>
<td></td>
</tr>
<tr>
<td>Benzene</td>
<td></td>
<td>0.00357</td>
<td>0.00357</td>
<td></td>
</tr>
<tr>
<td>Formaldehyde</td>
<td>0.11</td>
<td></td>
<td>0.11</td>
<td></td>
</tr>
<tr>
<td>Hexane</td>
<td>2.61</td>
<td>0.12</td>
<td>0.0103</td>
<td>2.87</td>
</tr>
<tr>
<td>Total</td>
<td>2.74</td>
<td></td>
<td></td>
<td>2.87</td>
</tr>
</tbody>
</table>

Maximum PTE of a single HAP (hexane) is 2.61 tons per year and total PTE of all HAPs is 2.87 tons per year. Emissions of a single HAP and a combination of HAPs are under 10 tons per year and 25 tons per year for the entire source. Since the HAPs emissions will be less than the major source thresholds in 40 CFR Part 63, the proposed Project will be an area source of HAPs.
4. Regulatory Applicability Review

A review of the potentially applicable federal and Ohio regulations has been conducted for the proposed Project. The following subsections summarize the applicability of these regulations to the proposed Project.

4.1 State Regulations

This analysis is based on the version of the Ohio Administrative Code (“OAC”) available at the time this application was prepared.

4.1.1 Ohio Revised Code 3745.11 Fees

OAC 3745.11(F) establishes fees for issuance of a permit to install approval for various types of sources including fuel burning equipment, various industrial categories etc. OEPA also provides a fee schedule on its website based on type of equipment to be permitted. An upfront application fee is not required and the permitting agency bills the applicants for permit fee prior to permit issuance.

4.1.2 OAC 3745-31 Permit to Install New Source of Air Pollution

The Ohio state regulations governing pre-construction permitting (“Permit to Install” or “PTI”) for sources of air pollution are contained in OAC 3745-31. In accordance with OAC 3745-31-02(A)(1), no person shall install or modify an air contaminant source without first obtaining a PTI from the Director. This document constitutes IU’s application for a PTI to construct and operate the Project. The relevant provisions of OAC 3745-31 are presented below by citation along with applicability conclusions for the Project. References to corresponding application materials and required analyses are also provided.

4.1.2.1 OAC 3745-31-01(AAAAAA) Stationary Source Definition

The term “stationary source” is defined at OAC 3745-31-01(AAAAAA) as collection of all emissions units that:

(a) belong to same industrial grouping;
(b) located on one or more contiguous or adjacent properties; and
(c) are under common control of the same person

OEPA Engineering Guide #58 details the “common control” criteria in regard to similar definition under Title V Program at OAC 3745-77-01. The guidance notes that:

“…[S]ome corporate structures can be very complex. It is possible to have a financial interest, but not have a controlling interest. The key issue for establishing common ownership for permitting purposes is whether control is exercised by a common entity. In the past, USEPA usually concludes that control is exercised by a parent corporation to its subsidiaries.”

14 http://www.epa.state.oh.us/portals/47/facts/feeschedule.pdf (last accessed on June 22, 2017).
15 Lucas County, Ohio is attainment or unclassifiable for all criteria pollutants.
The Project will be located adjacent to the existing Midwest Terminal, which provides material handling and other services to various entities at this Terminal. Midwest Terminal will receive and transfer oxide pellets for the IU HBI Facility under a contractual arrangement. However, IU and Midwest Terminal are separately owned and are not under the control of a ‘common entity.’ Also, neither entity exercises controlling interest over the other. Therefore, the two entities are considered separate stationary sources for permitting.

4.1.2.2 OAC 3745-31-01 Definition (Major Stationary Source)

OAC 3745-31-01(NNN) defines the “major stationary source” as a stationary source located in an attainment area with PTE of 100 tons per year or more that belong to one of the categories listed in OAC 3745-31-01(2)(a) or 250 tons per year or more that do not belong to one of the listed source categories. The proposed Project is not clearly within the ‘Iron and Steel Plant’ listed source category as it manufactures an intermediate form of iron different from the output of an iron and steel plant. Nonetheless, the Project is a major stationary source under the PSD program because it will have PTE of at least one of the regulated NSR pollutants greater than 250 and 100 tons per year. Without making a formal determination for this Project, this application conservatively references the 100 ton per year major source threshold and seeks a permit for a major stationary source under the prevention of significant deterioration (“PSD”) program.\(^{16}\)

4.1.2.3 OAC 3745-31-04 Applications

OAC 3745-31-04 outlines the application requirements for a PTI meeting the requirements of OAC 3745-31-05. It also requires application to be signed by principal executive officer of at least the level of vice president, or the duly authorized representative, if such representative is responsible for the overall operation of the facility. In addition, the application is to be made on the application forms provided by OEPA. This application meets the requirements of this rule. Application forms were completed online in the “Air Services” portal provided by OEPA. A copy of the permit application forms is also provided in Appendix A.

4.1.2.4 OAC 3745-31-05 Criteria for Decision by the Director

OAC 3745-31-05 contains PTI decision and approval criteria used by the Director in reviewing permit applications. In general, the rule provides that a PTI shall be approved and issued based on an application satisfactorily demonstrating that the installation and operation will:

1. Not prevent or interfere with the attainment or maintenance of applicable ambient air quality standards;\(^ {17}\)
2. Not result in a violation of any applicable laws including PSD review under OAC 3745-31-11 through 20; and
3. Employ best available technology (BAT) (with noted exceptions).

---

\(^{16}\) Lucas County, Ohio is attainment or unclassifiable for all criteria pollutants. https://www3.epa.gov/airquality/greenbook/anayo_oh.html (last accessed on May 10, 2017).

\(^{17}\) Table 3 in Engineering Guide 60 requires modeling for air contaminants if the emission rate exceeds Ohio Modeling Significant Emission rates. These rates match the PSD significant emission rates. Thus PSD requirements fulfill the obligation under Engineering Guide 69 for the proposed project.
The proposed project will be a new major stationary source under PSD, as defined in OAC 3745-31-01, subject to the requirements of OAC 3745-31-11 through 20. As noted in Table 3-20 and Table 4-1 below, the proposed project will result in emissions of PM, PM10, PM2.5, NOx, CO, and GHGs.

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>PTE (tons/year)</th>
<th>Major Source Threshold (tons/year)</th>
<th>Whether Major?</th>
<th>Significant Emission Rate (tons/year)</th>
<th>For PSD Whether Significant?</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM</td>
<td>97.76</td>
<td>100</td>
<td>No</td>
<td>25</td>
<td>Yes</td>
</tr>
<tr>
<td>PM10</td>
<td>138.64</td>
<td>100</td>
<td>Yes</td>
<td>15</td>
<td>Yes</td>
</tr>
<tr>
<td>PM2.5</td>
<td>136.53</td>
<td>100</td>
<td>Yes</td>
<td>10</td>
<td>Yes</td>
</tr>
<tr>
<td>NOx</td>
<td>478.37</td>
<td>100</td>
<td>Yes</td>
<td>40</td>
<td>Yes</td>
</tr>
<tr>
<td>SO2</td>
<td>21.65</td>
<td>100</td>
<td>No</td>
<td>40</td>
<td>No</td>
</tr>
<tr>
<td>CO</td>
<td>577.01</td>
<td>100</td>
<td>Yes</td>
<td>100</td>
<td>Yes</td>
</tr>
<tr>
<td>VOC</td>
<td>13.77</td>
<td>100</td>
<td>No</td>
<td>40</td>
<td>No</td>
</tr>
<tr>
<td>GHG/CO2e*</td>
<td>1,626,878</td>
<td>-NA, **</td>
<td>-NA-</td>
<td>75,000</td>
<td>Yes</td>
</tr>
</tbody>
</table>

*CO2e and GHGs regulated under OAC 3745-31-34.
**In accordance with U.S. Supreme Court decision in Utility Air Regulatory Group, Petitioner V. Environmental Protection Agency, et al. No. 12-1146, June 23, 2014, GHGs subject to PSD review only if the proposed project is subject to PSD review for at least one non-GHG regulated NSR pollutant.

As documented in this permit application, complying with the requirements of PSD review for the proposed Project meets the criteria above. Specifically, the best available control technology (BACT) review under OAC 3745-31-15 will satisfy the BAT requirement for regulated NSR pollutant emissions for the proposed project for all pollutants except SO2 and VOC. Also, the source impact analysis in OAC 3745-31-16 will satisfy the obligation to ensure attainment or maintenance of the applicable ambient air quality standards.

4.1.2.5 OAC 3745-31-05(A)(3)(a) Employ BAT

OAC 3745-31-05(A)(3) requires BAT for an individual air contaminant source installed after August 3, 2006 that has potential to emit after control of 10 tons per year or more. As noted in 4.1.2.4 above, for the proposed Project, increases in SO2 and VOC emissions are below the significant emissions rates. Therefore, emissions of these pollutants from the units under the Project are not subject to BACT requirements and require a separate BAT evaluation.

PTE of both VOC and SO2 are below 10 tons per year for all air contaminant sources proposed under the Project, except SO2 emissions from the reformer, which are above 10 tons per year. Therefore, only the reformer SO2 emissions are subject to the requirement to employ BAT.18 The reformer burner will use gaseous fuel (furnace top gas and natural gas), which is a low sulfur bearing fuel that minimizes the formation of SO2 emissions. Reformer SO2 PTE is 18.70 tons per year which is well below the PSD significant emission rate. Add-on SO2 control devices cannot cost effectively reduce SO2 emissions further. Therefore, use of naturally low-sulfur gaseous fuel, comprised of furnace top gas and natural gas, in the reformer is determined as BAT.

18 The rule limiting BAT to emission units at or above 10 tons per year in OAC rule 3745-31-05 is pending USEPA approval as part of the Ohio SIP. We will work with Ohio EPA to address this issue in the permit.
4.1.2.6 OAC 3745-31-11 through 20 Attainment Provisions

OAC 3745-31-11 through 20 contain provisions applicable to new major stationary sources or NSR projects that are major modifications for regulated NSR pollutants for which area is attainment. The proposed HBI Facility will be a new major stationary source, as noted in 4.1.2.2, with a potential to emit greater than 100 tons per year of one or more regulated NSR pollutants that is located in Lucas County, (designated as attainment for all regulated NSR pollutants). The proposed project will be subject to the PSD requirements noted in Table 4-2 for all regulated NSR pollutants for which the project results in a significant emissions increase as noted in Table 4-1 above.

Table 4-2. PSD Requirements for Project

<table>
<thead>
<tr>
<th>Citation</th>
<th>Requirements</th>
<th>Application Section</th>
</tr>
</thead>
<tbody>
<tr>
<td>OAC 3745-31-11</td>
<td>Allowable increments</td>
<td>6, Appendix E</td>
</tr>
<tr>
<td>OAC 3745-31-12</td>
<td>Data submission authority and minimum data submission requirements</td>
<td>Entire application</td>
</tr>
<tr>
<td>OAC 3745-31-13</td>
<td>Air pollutants covered</td>
<td></td>
</tr>
<tr>
<td>OAC 3745-31-14</td>
<td>Preapplication monitoring requirements</td>
<td>6, Appendix E</td>
</tr>
<tr>
<td>OAC 3745-31-15</td>
<td>Control technology review</td>
<td>5</td>
</tr>
<tr>
<td>OAC 3745-31-16</td>
<td>Source impact analysis</td>
<td>6, Appendix E</td>
</tr>
<tr>
<td>OAC 3745-31-17</td>
<td>Additional impact analysis</td>
<td>7</td>
</tr>
<tr>
<td>OAC 3745-31-18</td>
<td>Air quality models</td>
<td>6, Appendix E</td>
</tr>
<tr>
<td>OAC 3745-31-19</td>
<td>Notification to U.S. EPA and Federal Land Manager</td>
<td>OEPAs obligation; FLM notification Appendix E</td>
</tr>
<tr>
<td>OAC 3745-31-20</td>
<td>Innovative control technology</td>
<td>NA</td>
</tr>
</tbody>
</table>

4.1.2.7 OAC 3745-31-21 Nonattainment Provisions

As noted in OAC 3745-31-21, the requirements of these provisions apply to a major stationary source or a major modification located in a nonattainment area. The proposed HBI Facility will be located in Lucas County that is designated attainment or unclassifiable in 40 CFR §81.336. Therefore, the requirements of nonattainment provisions do not apply to the proposed project.

4.1.2.8 OAC 3745-31-28 Review of Major Stationary Source of HAPs

As shown in Table 3-23, the source wide PTE of a single HAP is below 10 tons per year and any combination of HAPs is below 25 tons per year. Therefore, this source will not qualify as a major MACT source defined in OAC 3745-31-01 (KKK). Requirements of OAC 3745-31-28 do not apply to the proposed project as it does not involve construction of a major MACT source.

4.1.2.9 OAC 3745-31-34 Permit to Install for Major Stationary Source for GHGs

The proposed project will be a new major stationary source and will emit or have PTE 75,000 tons per year of CO₂ equivalent. In accordance with OAC 3745-31-34 (A) and (E), GHGs emissions from the proposed project are subject to the BACT requirements in OAC 3745-31-15. Section 5 includes the GHG BACT analysis for the project.
4.1.3 **OAC 3745-77 Title V Permit Rules**

Per OAC 3745-77-02(B), any ‘major source’ is subject to the Title V permitting requirements under OAC 3745-77. The proposed HBI Facility will have PTE of at least one air pollutant greater than or equal to 100 tons per year and qualifies as a ‘major source’ under OAC 3745-77-01(X). In accordance with OAC 3745-77-04(D), a Title V permit application will be due with 12 month after commencing operation of the HBI Facility that is subject to the preconstruction permit requirement under Part C of Title I of federal Clean Air Act.

4.1.4 **OAC 3745-15 General Provision on Air Pollution Control**

OAC 3745-15 specifies general requirements to control air pollution in Ohio, and includes provisions regarding de-minimis sources and emission source malfunction requirements that apply to the proposed project. OAC 3745-15-05 provides an exemption from permitting requirements for de minimis sources. The proposed Project application address equipment that does not meet the exemption qualification under this rule and is subject to the requirement to obtain PTI. OAC 3745-15-06(B) requires that any malfunction of an emission source or air pollution control equipment that causes the violation of any applicable law requires immediate notification of the Ohio EPA. If the malfunction continues for over 72 hours, the owner or operator shall provide a written statement within 2 weeks that details a program to prevent, detect, and correct similar future failures or breakdowns of equipment. OAC 3745-15-07 prohibits emissions that constitute a public nuisance. IU will comply with the requirements of OAC 3745-15 as applicable to the Project and related emission units.

4.1.5 **OAC 3745-16 Stack Height Requirements**

In accordance with OAC 3745-16-02, the requirements of this rule apply to all sources except for noted exemptions that are not applicable to the Project. Stack heights for units proposed in the Project will be consistent with the requirements of this rule.

4.1.6 **OAC 3745-17-07 Control of Visible Particulate Emissions from Stationary Sources**

OAC 3745-17-07(B)(1)(a) specifies a general visible emissions limitation of 20% opacity, as a six minute average. Other subsections of this regulation provide for various exemptions from the visible emissions limitations. Use of proposed controls for PM emissions will ensure that the equipment proposed under the Project will be in compliance with this standard.

4.1.7 **OAC 3745-17-08 Restriction of Emissions of Fugitive Dust**

OAC 3745-17-08(A)(1) applies to fugitive dust sources located in City of Toledo, Lucas County listed in Appendix A to the rule. OAC 3745-17-08(B) requires sources subject to this rule to use reasonably available control measures to prevent fugitive dust from becoming airborne. IU will comply with the requirements of this rule for the proposed Project operations.

4.1.8 **OAC 3745-17-10 Restrictions on Particulate Matter from Fuel Burning Equipment**

OAC 3745-17-10(A) specifies applicability of this rule to fuel burning installations for the primary purpose of producing heat or power by indirect heat transfer. Only the proposed reformer under the Project involves indirect transfer of heat and is subject to the requirements of this rule. In accordance with OAC 3745-17-10(B)(1), particulate emissions limitation 0.020
lb/MMBtu is applicable to the reformer. The potential emission rate for PM from this unit will be 0.005 lb/MMBtu, well in compliance with the applicable limitation.

4.1.9 OAC 3745-17-11 Restrictions on Particulate Matter from Industrial Processes

Per OAC 3745-17-11(A)(1), requirements of this rule apply to any operation, process, or activity which releases or may release particulate matter into the ambient air. The proposed Project equipment will be in compliance with the applicable emission limitations in OAC 3745-17-11(B)(1) for sources located in Lucas County.

4.1.10 OAC 3745-18-06 General Emission Limit Provisions for Sulfur Dioxide

OAC 3745-18-06 establishes SO₂ emission limits for new sources. The proposed Reformer uses natural gas fuel and, in accordance with OAC 3745-18-06(A), is exempt from the requirements of this rule. The proposed emergency diesel generator exceeds the 10 MMBtu per hour threshold in OAC 3745-18-06(B) and is subject to the requirements under OAC 3745-18-06(E)(2), which establishes an SO₂ limit in lb/hour based on the process weight rate for the engine. The proposed engine will be in compliance with the SO₂ lb/hour emission rate calculated in accordance with the following equation:

\[
AER = 30 \times P^{0.67}
\]

Where P is the process weight rate in tons per hour and AER is the allowable emission rate in pounds of sulfur dioxide per hour.

4.1.11 OAC 3745-18-54 Lucas County Emission Limits

The proposed Project will not involve construction of coal-fired steam generating unit. In addition, it is not one of the listed facilities under OAC 3745-18-54. Therefore, the requirements of this rule do not apply to the proposed project.

4.1.12 OAC Rule 3745-21-07 Control of Emissions of Organic Materials from Stationary Sources

The proposed project will not involve construction of any units that meet the applicability requirements in OAC 3745-21-07(A)(3). Therefore, the requirements of this rule do not apply to the proposed project.

4.1.13 OAC Rule 3745-21-08 Control of Carbon Monoxide Emissions from Stationary Sources

The proposed Project will not involve construction of any units identified in OAC 3745-21-08(D) and (E). Therefore, the requirements of this rule do not apply to the proposed project.

4.1.14 OAC Rule 3745-21-09 Control of Emissions of Volatile Organic Compounds from Stationary Sources

The proposed project will not involve construction of any units that meet the applicability requirements in OAC 3745-21-09(A)(1). Therefore, the requirements of this rule do not apply to the proposed project.
4.1.15 OAC Rule 3745-24 NOx and VOC Emission Statements

The proposed project will not be located in a County that is designated nonattainment for ozone. Therefore, per OAC 3745-24-02(A), the emissions statements requirement do not apply to the proposed sources.

4.1.16 OAC Rule 3745-110 Nitrogen Oxides – Reasonably Available Control Technology

The proposed project will not involve construction of any units that meet the applicability requirements in OAC 3745-110-02(A)(2). Therefore, the requirements of this rule do not apply to the proposed project.

4.1.17 OAC Rule 3745-114-01 Toxics Air Contaminants

The toxics air contaminant (TAC) emissions under this rule are addressed under Engineering Guide 69 and Engineering Guide 71 issued by OEPA.19 Engineering Guide 71 As shown in Appendix C, PTE of only hexane for the proposed Project exceeds the Ohio modeling significant emission rate of one (1) tons per year in Table 3. Results of the modeled impacts analysis for hexane emissions from the proposed project is presented in section 6 and Appendix E of the application.

4.2 Federal Regulations

4.2.1 New Source Performance Standards (40 CFR Part 60)

Applicability of the NSPS requirements for the proposed units is presented below.

4.2.1.1 General Provisions, 40 CFR Part 60, Subpart A

IU will comply with the applicable requirements under general provisions of 40 CFR Part 60 Subpart A. These will include notifications, compliance testing, monitoring, recordkeeping and reporting provisions of the rule.

4.2.1.2 Standards of Performance for Stationary for Metallic Mineral Processing Plants, 40 CFR Part 60, Subpart LL

NSPS 40 CFR Part 60, Subpart LL applies to metallic mineral processing plants that commence construction after August 24, 1982. The proposed HBI Facility does not meet the definition of ‘metallic mineral processing plant’ in 40 CFR § 60.381 as it does not produce metallic mineral concentrate from ore and it is a non-adjacent facility outside the defined scope of metallic mineral processing. Therefore, the requirements of this rule do not apply to the equipment proposed under the Project.

4.2.1.3 Standards of Performance for Stationary Compression Ignition Internal Combustion Engine, 40 CFR Part 60, Subpart IIII

NSPS 40 CFR Part 60, Subpart IIII applies to stationary compression ignition RICE, including fire-pumps that commence construction after 2009.

(1) The proposed fire-pump booster engine will be subject to the requirements of this rule as noted below:
(a) Comply with the emission limitations in Table 4-3 below. (40 CFR §§60.4202(d) and 60.4205(c), Table 4)

Table 4-3. NSPS III Requirements for the 250 HP Fire Pump booster engine

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Emission Standard (g/HP-hr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>NMHC+NOx</td>
<td>3.0</td>
</tr>
<tr>
<td>CO</td>
<td>2.6</td>
</tr>
<tr>
<td>PM</td>
<td>0.15</td>
</tr>
</tbody>
</table>

IU plans to purchase a manufacturer certified fire-pump RICE that will be in compliance with the above limitations.

(b) Use ultra-low sulfur diesel fuel per the requirements of 40 CFR §80.510(b). (40 CFR §60.4207(b))

(2) The proposed emergency engine generator will be subject to the requirements of this rule as noted below:

(a) Comply with the emission limitations in Table 4-4 below from 40 CFR §89.112. (40 CFR §§60.4202(a)(2) and 60.4205(b))

Table 4-4. NSPS III Requirements for the 2,922 HP Emergency Engine

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Emission Standard (g/kW-hr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>NMHC+NOx</td>
<td>6.4</td>
</tr>
<tr>
<td>CO</td>
<td>3.5</td>
</tr>
<tr>
<td>PM</td>
<td>0.20</td>
</tr>
</tbody>
</table>

40 CFR §89.112(a) Tier II standards for units >560 kW

IU plans to purchase a manufacturer certified emergency RICE generator that will be in compliance with the above limitations.

(b) Use ultra-low sulfur diesel fuel per the requirements of 40 CFR §80.510(b). (40 CFR §60.4207(b))

4.2.2 National Emissions Standards for Hazardous Air Pollutants (40 CFR Part 63)
Applicability of the NESHAP requirements for the proposed units is presented below. Source-wide PTE of HAPs provided in 3.2.4 lists PTE of single HAPs and combination of HAPs as less than 10 tons per year and 25 tons per year, respectively. Therefore, the proposed Project will be an area source in 40 CFR §63.2 for applicability of NESHAP requirements.

4.2.2.1 National Emission Standards for Hazardous Air Pollutants: Taconite Iron Ore Processing, 40 CFR Part 63, Subpart RRRRR
NESHAP 40 CFR 63 Subpart RRRRR applies to a taconite iron ore processing plant at major sources of HAP emissions. The HBI Facility does not meet the definition of a taconite iron ore processing plant.
processing facility as defined in 40 CFR §63.9652. Further, the Project is an area source and will not be subject to the NESHAP requirements.

4.2.2.2 National Emission Standards for Hazardous Air Pollutants: Stationary Reciprocating Internal Combustion Engines, 40 CFR Part 63, Subpart ZZZZ

NESHAP 40 CFR 63 Subpart ZZZZ applies to RICE located at area and major sources of HAP emissions. The Project, an area source, will involve construction of two emergency RICE. Pursuant to 40 CFR § 63.6590(c)(1) new stationary RICE located at an area source that are subject to 40 CFR Part 60 IIII are exempt from 40 CFR Part 63 Subpart A and Subpart ZZZZ.

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

NESHAP 40 CFR 63 Subpart JJJJJJ applies to boilers located at area sources of HAP emissions. The Project will involve construction of a reformer that will indirectly heat the natural gas for producing reforming gases. Pursuant to 40 CFR § 63.11237, a ‘boiler’ is defined as “... an enclosed device using controlled flame combustion in which water is heated to recover thermal energy in the form of heat and/or hot water.” The reformer process will not involve heating of water to recover thermal energy. Therefore, this unit is not an “affected source” under this rule and is not subject to the requirements of 40 CFR Part 63 Subpart A and Subpart JJJJJJ.

4.2.3 Compliance Assurance Monitoring

The Compliance Assurance Monitoring (CAM) program is codified in 40 CFR Part 64. CAM requirements apply to any pollutant specific emissions unit with uncontrolled potential emissions above the major source threshold (100 tons/year) that uses a control device to achieve compliance with an emission limitation or standard. The uncontrolled PTE of some of the new emissions units proposed in the Project will be above the major source thresholds for all pollutants. Therefore, CAM requirements are applicable to the Project. Per 40 CFR §64.5(a)(1), CAM plan information is required as part of the initial application for a Part 70 Operating Permit.
5. **Best Available Control Technology**

This section presents the required BACT reviews for the proposed Project. It includes a general discussion of the BACT analysis procedure employed. This general discussion is followed by a site-specific case-by-case BACT analysis for the new emissions units to be constructed as part of the Project. The results of the BACT analyses for the proposed Project are summarized in Table 5-1.

### 5.1 BACT Applicability

The Project involves constructing a new HBI manufacturing facility consisting of a reformer, DRI reactor, and the necessary support facilities such as a cooling tower, raw material and product handling systems, and emergency equipment. As described in section 4.1.2.4, the project is subject to PSD review for PM, PM10, PM2.5, NOx, CO and GHGs. For the Project, applicability of BACT is required pursuant to OAC 3745-31-15(C) as follows:

The owner or operator of a new major stationary source shall apply BACT to the major stationary source for each regulated NSR pollutant that the major stationary source would have the potential to emit in significant amounts.  

In the case of the proposed Project, BACT is applicable to all of the newly constructed units that have the potential to emit PM, PM10, PM2.5, NOx, CO and GHGs in any amount. Table 5-2 lists each unit-pollutant combination subject to BACT review.

### 5.2 BACT General Approach

This section presents an outline of BACT approach for the proposed Project units for regulated NSR pollutants subject to PSD review.

#### 5.2.1 Best Available Control Technology Definition

The definition of BACT at OAC 3745-31-01(S) is as follows:

An emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each regulated NSR pollutant which would be emitted from any proposed major stationary source or major modification which the director, on a case-by-case basis, taking into account energy, environmental and economic impacts and other costs, determines is achievable for such major stationary source or major modification through application of production processes or available methods, systems and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of BACT result in emissions of any pollutant that would exceed the emissions allowed by any

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20 Per OAC 3745-31-34(E), only the BACT requirements apply to projects that are subject to PSD review for GHGs.
Table 5-1. Summary of BACT Determinations for the Proposed Project

<table>
<thead>
<tr>
<th>EU ID</th>
<th>Unit Description</th>
<th>Pollutant</th>
<th>Proposed BACT</th>
</tr>
</thead>
<tbody>
<tr>
<td>P-2</td>
<td>Reformer Exhaust</td>
<td>PM (filterable)</td>
<td>0.005 lb/MBtu and use of good combustion practices</td>
</tr>
<tr>
<td></td>
<td></td>
<td>PM10/PM2.5</td>
<td>0.012 lb/MBtu and use of good combustion practices</td>
</tr>
<tr>
<td></td>
<td></td>
<td>NOx</td>
<td>0.06 lb/MBtu and use of low NOx burners and good combustion practices</td>
</tr>
<tr>
<td></td>
<td></td>
<td>CO</td>
<td>0.031 lb/MBtu and use of good combustion practices</td>
</tr>
<tr>
<td></td>
<td></td>
<td>GHGs</td>
<td>1,554,047 tons per year of CO&lt;sub&gt;e&lt;/sub&gt; and use of good combustion practices</td>
</tr>
<tr>
<td>P-6</td>
<td>Flare (During Process Upset and Startup/Shutdown)</td>
<td>PM/PM10/PM2.5, NOx, CO, GHGs</td>
<td>Flaring minimization plant design to meet 40 Part 60.18</td>
</tr>
<tr>
<td></td>
<td>Flare Pilot</td>
<td>PM/PM10/PM2.5, NOx, CO, GHGs</td>
<td>Use of natural gas and follow good combustion practices</td>
</tr>
<tr>
<td>TR-28</td>
<td>Charge Hopper Exhaust</td>
<td>PM/PM10/PM2.5</td>
<td>0.007 gr/dscf and use of venturi scrubber</td>
</tr>
<tr>
<td>P-1</td>
<td>Bottom Seal Gas Exhaust</td>
<td>NOx, CO, GHGs</td>
<td>Work practices standards</td>
</tr>
<tr>
<td>P-3</td>
<td>Hot Briquette Exhaust</td>
<td>NOx, CO, GHGs</td>
<td>Work practices standards</td>
</tr>
<tr>
<td>P-4</td>
<td>Briquette Cooling System Vapor Removal Vent</td>
<td>NOx, CO, GHGs</td>
<td>Work practices standards</td>
</tr>
<tr>
<td>P-5</td>
<td>Degasser Exhaust</td>
<td>CO, CO&lt;sub&gt;2&lt;/sub&gt;</td>
<td>Work practices standards</td>
</tr>
<tr>
<td>P-7</td>
<td>Cooling Tower</td>
<td>PM/PM10/PM2.5</td>
<td>0.0005% drift loss, use of mist eliminator and performance of inspection and maintenance</td>
</tr>
<tr>
<td>P-8</td>
<td>Emergency Diesel Fire Pump Booster Engine</td>
<td>PM/PM10/PM2.5, NOx, CO</td>
<td>Follow requirements of NSPS Subpart III</td>
</tr>
<tr>
<td>P-9</td>
<td>Emergency Diesel Generator Engine</td>
<td>PM/PM10/PM2.5, NOx, CO</td>
<td>Follow requirements of NSPS Subpart III</td>
</tr>
<tr>
<td>P-8, P-9</td>
<td>Emergency Engines</td>
<td>GHGs</td>
<td>None</td>
</tr>
<tr>
<td>FugGHG</td>
<td>Fugitive Components Leaks</td>
<td>GHGs</td>
<td>Follow good industrial design</td>
</tr>
<tr>
<td>Various</td>
<td>Oxide Material Handling and Storage Systems</td>
<td>PM/PM10/PM2.5</td>
<td>Baghouses for emission points with outlet grain loading of 0.0025 gr/dscf. Dust suppression for fugitive operations.</td>
</tr>
<tr>
<td>Various</td>
<td>HBI Material Handling and Storage Systems</td>
<td>PM/PM10/PM2.5</td>
<td>Scrubbers for emission points with outlet grain loading of 0.0025 gr/dscf. Dust suppression for fugitive operations.</td>
</tr>
</tbody>
</table>
Table 5-2. Unit-Pollutant Combinations Subject to BACT Review

<table>
<thead>
<tr>
<th>Unit Description</th>
<th>PM/PM10/PM2.5</th>
<th>NOx</th>
<th>CO</th>
<th>GHGs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oxide Storage and Handling</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Furnace Charge Hopper Scrubber</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Bottom Seal Gas Scrubber</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>Reformer Exhaust</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Hot Briquette Exhaust</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>Briquette Cooling System Vent</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>Degasser Exhaust</td>
<td></td>
<td></td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Flare</td>
<td></td>
<td>X</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>HBI Storage and Handling</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cooling Tower</td>
<td></td>
<td></td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>Emergency Fire Water Booster</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>Emergency Generator</td>
<td></td>
<td>X</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>Fugitive Emissions from Leaks</td>
<td></td>
<td></td>
<td></td>
<td>X</td>
</tr>
</tbody>
</table>

applicable standard under 40 CFR Parts 60, 61, and 63. If the director determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be approved by the director instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emission reduction achievable by implementation of such design, equipment, work practice or operation and shall provide for compliance by means which achieve equivalent results.

This definition of BACT is generally consistent with that in the federal Clean Air Act as amended in 1977. The Clean Air Act Amendments of 1990 added the phrase “clean fuels” to the list of candidate methods, systems, and techniques.

5.2.2 Methodology for the BACT Analysis

OEPAs’s air quality regulations do not prescribe a procedure for conducting a case-by-case BACT analysis but, by convention, BACT determinations are typically made following the top-down approach. Accordingly, the BACT analyses presented in this application utilize the top-down approach.

Under the “top-down” approach, progressively less stringent control technologies are analyzed until a level of control considered BACT is determined, based on the most effective control option that is determined to result in acceptable environmental, energy, and economic impacts. More specifically, the top-down BACT analysis methodology consists of five steps as follows:

---

21 P.L. 95-95, § 127(a).
1. Identify all “available” control options that might be utilized to reduce emissions of the subject pollutant for the type of unit subject to BACT.

2. Eliminate those available options that are technically infeasible to apply to the specific unit under consideration.

3. Rank the remaining feasible control options by control effectiveness.

4. Evaluate economic, energy and/or environmental impacts of the each control option as applied to the subject units, rejecting those options for which the adverse impacts are inappropriate.

5. Based on the most effective control option not rejected in Step 4, select an emission limit or work practice standard as BACT, reflecting the level of control continuously achievable with the selected control option.

5.2.3 Basic Purpose and Design of the Project

To determine whether a particular technology or technique is “available” for consideration in the BACT analysis, or would fundamentally redefine the proposed source, and must therefore be omitted from consideration in the BACT analysis “a permitting authority should look first at the administrative record to see how the applicant defined its goal, objectives, purpose or basic design.”

The permitting authority must take a “hard look” and determine “which design elements are inherent to [the] purpose [of the facility], articulated for reasons independent of air quality permitting, and which design elements may be changed to achieve pollutant emission reductions.”

IU’s basic purpose, design, and fundamental objective for the Project is to construct a HBI manufacturing facility using natural gas based reducing gas (from reformer process) on the proposed 130 acre site in Lucas County, Ohio. This facility will be designed to produce up to 2.48 million tons of HBI. The facility will use iron pellets and natural gas as feedstock. The project design requires use of a reformer unit to generate reducing gas by reforming natural gas that will be used in the DRI reactor for producing DRI and HBI. These characteristics are essential in realizing the project objectives of meeting steel industry customer demand.

5.2.4 BACT Baseline

As used in the BACT analyses presented herein, the term “BACT baseline” refers to the following requirement in the definition of BACT:

*In no event shall application of BACT result in emissions of any pollutant that would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60, 61, and 63.*

Thus, any applicable OEPA, State or federal limit on emissions of a BACT-subject regulated NSR pollutant from a given unit serves as a baseline for purposes of the BACT evaluations.

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an example, OAC 3745-17-10 (Restrictions on particulate emissions from fuel burning equipment) limits PM emissions to be no greater than 0.020 pound per million Btu of actual heat input. This limit serves as the PM BACT baseline for the proposed reformer.

5.2.5 Available Control Strategies

In the first step of the BACT analysis, all potentially “available” control strategies are identified for further consideration. In the context of the first step of a top-down BACT analysis, U.S. EPA’s guidance describes “available” control strategies as:

[T]hose air pollution control technologies or techniques with a practical potential for application to the emissions unit and the regulated pollutant under evaluation. [emphasis added]

In the BACT analyses herein, the term “available” is used, consistent with the U.S. EPA guidance, to refer to any control strategy that is potentially applicable to the source type in question (i.e., a technology or control option that has a practical potential for application to the source category in general). These may include fuel cleaning or treatment, inherently lower polluting processes, and end of pipe control devices. All identified control strategies that are not inconsistent with the fundamental purpose and basic design of the proposed facility are listed in this step.

As discussed in subsection 5.2.6 below, the second step of the BACT analysis addresses site-specific or design-specific criteria that would prevent an otherwise available technology from being applied in the particular case of the proposed project. This “technical feasibility” question is separate and distinct from the criteria used to determine whether a control option is considered to be “available” for purposes of determining BACT.

5.2.6 BACT Technical Feasibility Criteria

In the second step of a top-down BACT analysis, potentially available control strategies are evaluated for technical feasibility. A technically feasible control strategy is one that has been demonstrated to function efficiently on an emissions unit that is identical or similar to the emissions unit under review. For the purposes of assessing technical feasibility of an add-on control technology, the determination of whether an emissions unit should be considered to be identical or similar is usually based on the physical and chemical characteristics of the gas stream to be controlled. An add-on control technology applicable to one emissions unit may not be technically feasible for application to an apparently similar unit depending on differences in physical and chemical gas stream characteristics, and rejection of a control option based on

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25 For the purposes of BACT analyses, we did not consider process weight rate rule limitations in OAC 3745-17-11 as baseline as the process weight rate limitations are relatively larger than the PTE of PM for the emissions unit.
technical infeasibility for BACT purposes is appropriate if “it is uncertain the control device will work in the situation currently undergoing review.”

For control strategies that are not demonstrated, the analysis of technical feasibility is somewhat more involved. Two key concepts are important in determining whether an undemonstrated technology is feasible: “availability” and “applicability.” A technology is considered “available” if it can be obtained by the applicant through commercial channels or is otherwise available within the common sense meaning of the term. An available technology is “applicable” if it can reasonably be installed and operated on the source type under consideration. A technology that is both available and applicable is technically feasible.

## 5.3 HBI Process Overview

The HBI production process core plant consists of two main processes, a reformer and the DRI reactor (reduction furnace).

The reformer produces the reducing gases (mainly H\textsubscript{2} and CO) that is used to reduce iron oxide in the iron ore pellets in the DRI reactor. The reformer is a proprietary tubular style design where natural gas feedstock disassociates to form a reducing gas rich in H\textsubscript{2} and CO. The reducing gas removes oxygen from the oxide pellets. Floor-fired (burners are installed on the floor) main burners that are located on the bottom of reformer box between tube rows and between the outside tube rows and reformer wall provide heat for the reforming reactions. Preheated air for combustion in the burners is provided by the heat recovery system by the main air blower. Reformer box is lined by refractory material. Natural gas-fired auxiliary burners maintain the temperature in reformer box during plant idle situation to reduce both restart time and thermal cycling of the reformer tubes.

Uniform heat distribution along the reformer length is ensured by use of separate sized flue gas port for each flue gas header in the reformer bays. The flue gas headers are refractory lined and expansion joints are provided between the single sections of the headers to compensate for thermal expansion. Waste heat recovery system recovers the heat from the flue gas exiting the reformer via the flue gas headers.

In the reduction furnace, the reducing gas is supplied from the tuyers located in the bottom of the reactor. Oxide is charged from the top of the reactor. Inert seal gas, that is cooled flue gas from the reformer, is used for sealing the top of the furnace. Seal gas escapes through the charge hopper as the charge hopper discharges oxide into the furnace. The gas flow is counter current to the descending oxide. At the top of the reactor, the partially spent reducing gas exits and it is recompressed, enriched with natural gas, preheated, and transported back to the reformer (“top gas”). The top gas is reformed in the reformer to 95% H\textsubscript{2} and CO, which is then reused in the reactor. A portion of the top gas is mixed with natural gas as fuel for use in the reformer burners.

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29 In Step 2 of a top-down BACT analysis, the term “availability” has a different meaning than the term “available” in Step 1. Control strategies that are not “available” in Step 1 are not considered in Step 2.
The DRI material is discharged from the reactor via a dynamic seal leg and a hydraulically driven variable speed hot wipe bar. The bottom seal gas (nitrogen) is vented through a vent line that is collected in a dilution hood. The speed of the lower burden feeder is closely ratioed to the average discharge rate of the reactor to achieve a uniform flow of the material from the lower cone to lower seal leg. The hot DRI material flows across the wiper bar and then passes through a set of hydraulically driven enclosed screens that limit the size of the product passing into surge hopper of the product discharge chamber. The material is discharged from the surge hopper into one or more feed legs. These feed legs connect to briquette machine to produce HBI or the bypass feed screw for producing hot or cold DRI.

In order to prevent the reducing gas from escaping the reduction furnace, high pressure seal gases are applied to both the charging and discharging openings. The seal gas escapes from the opening during oxide charge and product discharge from the furnace while retaining the reducing gas. The fines generated from oxide passing through the furnace escape along with seal gas. Top seal gas will be a small amount of flue gas (products of combustion) from the reformer exhaust. For bottom seal gas IU is planning to use nitrogen gas in place of cooled reformer flue gas. Some of the residual seal gas from the bottom of the furnace is also released from the briquette machine during the briquette making process.

The reduction furnace runs as close to steady state operations as possible to produce HBI of acceptable quality. Due to the nature of the reducing gas cycle system, during process upset or burden shift conditions, the pressure of reducing gas must be maintained below that of the seal gas system. This will prevent release of uncombusted reducing gases directly to the atmosphere from top and/or bottom seal. During these conditions reducing gases are routed to the pressure relief vent (flare) for flaring. Also during the process startup and shutdown events, the reducing gases are routed to the flare. The flare prevents release of carbon monoxide from the system by combusting the reducing gases and uses a natural gas fired pilot flame to ensure ignition of reducing gases.

The required direct contact process water comes in contact with the process gases during cooling process. Some of the gas constituents, mostly CO, is dissolved in water at elevated pressure in the system. In order to minimize fugitive CO emissions at the clarifier and to reduce scaling in process water ducts, a forced degassing system will be used. The return water flow from the top gas scrubber weir (after depressurization) will be routed to a degasser vessel. Air will flow upwards in countercurrent to the down flowing hot return water in this vessel releasing majority of dissolved CO. CO emissions are collected in the degasser vent gas flow and safely released to the atmosphere.

### 5.4 Reformers PM/PM10/PM2.5 BACT Analysis

This section presents the required PM/PM10/PM2.5 BACT analysis for the proposed reformer main flue ejector stack. The top gas contains small amount of incombustible solids in the stream as it leaves the reactor top. These solids are removed from the top gas as it leaves the reactor using a top gas venturi scrubber where it is cleaned and cooled. Approximately one third of the cleaned top gas and supplemental natural gas is combusted as fuel in the reformer.
More than half of reformer PM10/PM2.5 emissions consist of condensable particulate matter. Particulate matter emissions from top gas and natural gas fired reformer consist of:

- Inert contaminants in top gas and natural gas;
- Sulfates from oxidation of fuel sulfur and odorants;
- Dust in the ambient air used for combustion;
- Suspended and dissolved solids in the water used for humidification; and
- Compounds resulting from incomplete combustion of the fuel.

Virtually all of a reformer’s particulate emissions are PM2.5. Accordingly, technologies that are designed to reduce filterable PM10/PM2.5 will reduce PM (which is filterable only) emissions as well. Thus, these pollutants are appropriately considered together in this BACT analysis.

### 5.4.1 PM/PM10/PM2.5 BACT Baseline

OAC 3745-17-10 (Restrictions on particulate emissions from fuel burning equipment) limits PM emissions to 0.020 pound per million Btu of actual heat input. Since the allowable rate calculated is significantly larger than the PTE of PM from the reformer, this BACT baseline value is irrelevant to the BACT analysis (i.e., the potential emissions of PM are far below this baseline value making any PM BACT limit more restrictive than the applicable PM standard).

### 5.4.2 Step 1 – Identify Available PM/PM10/PM2.5 Control Options

A review of the U.S. EPA’s RBLC database identified no add-on controls for particulate matter emissions from reformer. A summary of the precedents identified from this review and other known permit precedents for reformers is presented in Table 5-3.

Based on a review of available information and in particular recent reformer BACT determinations, the control strategies that may be considered to be “available” for limiting PM/PM10/PM2.5 emissions from a reformer include:

- Good combustion practices;
- Combustion air filtration; and
- Use of clean fuels such as natural gas.

Other alternative control technologies that have been used to limit particulate emissions from external combustion sources firing liquid and solid fuels such as fabric filters and ESPs have never been applied to gas-fired combustion sources. These add-on technologies are not considered to be available control options in the context of this BACT analysis because they do not have a practical potential for application to control particulate emissions from the planned gas-fired reformer. There are no known applications of such controls to any similar source.

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Table 5-3. Summary of PM/PM10/PM2.5 BACT Precedence for Gas-Fired Reformers

<table>
<thead>
<tr>
<th>RBLC ID/ State</th>
<th>Facility Name</th>
<th>Permit Date</th>
<th>Process Description</th>
<th>Capacity (MMBtu/hr)</th>
<th>Fuel¹</th>
<th>Control²</th>
<th>Emission Limit lb/MMBtu</th>
</tr>
</thead>
<tbody>
<tr>
<td>LA-0317</td>
<td>Methanex Geismar Methanol Plant</td>
<td>12/22/2016</td>
<td>Steam Methane Reformer</td>
<td>2,346</td>
<td>NG</td>
<td>Proper Burner Design</td>
<td>None</td>
</tr>
<tr>
<td>LA-0306</td>
<td>Tomchem Pollock LLC</td>
<td>12/20/2016</td>
<td>Reformer</td>
<td>337</td>
<td>NG</td>
<td>GCP</td>
<td>0.00745</td>
</tr>
<tr>
<td>TX-0774</td>
<td>Ticona Polymers Inc. Bishop</td>
<td>11/12/2015</td>
<td>Reformer</td>
<td>1,190</td>
<td>NG</td>
<td>GCP</td>
<td>0.0053 (calculated)</td>
</tr>
<tr>
<td>ND-0033</td>
<td>Grand Forks Fertilizer Plant</td>
<td>8/10/2015</td>
<td>Primary Reformer</td>
<td>1,006</td>
<td>NG</td>
<td>GCP</td>
<td>0.003 (calculated)</td>
</tr>
<tr>
<td>TX-0782</td>
<td>Equistar Chemicals Channelview</td>
<td>1/13/2015</td>
<td>Reformer Furnace</td>
<td>1,615</td>
<td>NG</td>
<td>GCP</td>
<td>0.003 (calculated)</td>
</tr>
<tr>
<td>TX-0725</td>
<td>Voestalpine Texas DRI facility</td>
<td>3/18/2014</td>
<td>Gas Reformer</td>
<td>1,591</td>
<td>NG</td>
<td>Top gas cleaning</td>
<td>0.0044 gr/dscf</td>
</tr>
<tr>
<td>LA-0248</td>
<td>Consolidated Environmental DRI facility (never built)</td>
<td>1/27/2011</td>
<td>Reformer</td>
<td>1,390</td>
<td>NG</td>
<td>Top gas cleaning</td>
<td>0.0027 gr/dscf</td>
</tr>
</tbody>
</table>

1 - NG- natural gas  
2 - GCP – Good combustion practices

For process gas firing, cleaning of the process gas prior to combustion is also considered as feasible. Potential control options to consider include:

- Fabric filters (baghouse),
- Electrostatic precipitator (ESP),
- Venturi scrubber, and
- Cyclone.

**Fabric Filters** – A fabric filter or baghouse separates particulate matter from a dry exhaust gas stream. The baghouse efficiency is largely insensitive to fluctuations in the dust loading of the gas stream. Baghouses have been used in the iron and steel industry to control particulate matter emissions in sources that do not have high temperature, high moisture, or corrosive materials. Air from the emission unit exhaust is either pushed through (positive pressure) or pulled across (negative pressure) fabric filter material and clean the gas stream is exhausted to the atmosphere.

**Electrostatic Precipitator** – ESPs use a set of electrostatic fields to impart charge to particulate matter in the exhaust gas stream. The charged particles then adhere to grounded collection surfaces. The system uses periodic rapping or vibrations to collect the adhered materials in a hopper at the bottom of the ESP. Variations in particulate loading can adversely affect the removal efficiency. These are also ineffective with materials that have certain electrical properties.

**Venturi Scrubber** – In a particulate venturi scrubber, the exhaust gas stream is contacted with a scrubbing liquid by spraying the liquid in a contacting tower to remove the particulate matter. The scrubbers reduce particulate matter emissions by removing particles by impacting them with the liquid droplets, usually water, and then filtering or clarifying the water media. Scrubber can handle gas stream with high moisture content and variable dust loading.
Cyclone – Centrifugal cyclone collectors use cyclonic action to separate particulate matter from the exhaust gas streams. Gas stream enters the device at an angle and is spun rapidly. Centrifugal forces created by the circular motion moves the particles toward the wall of the device and drop to the bottom hopper.

Good Combustion Practices – GCP optimizes conditions in the combustion zone of a fuel combustion device. Such optimization comprise of various options including air to fuel ratio, firebox temperature monitoring etc.

5.4.3 Step 2 – Eliminate Technically Infeasible PM/PM10/PM2.5 Controls

Use of a venturi scrubber for cleaning fuel gas, gaseous fuel firing, and good combustion practices are the only available control strategies identified and are considered to be a technically feasible for establishing the PM/PM10/PM2.5 BACT limits for the reformer.

Particulates in the DRI process gas are formed in a reduced oxygen atmosphere, and these particles are known to react to oxygen when exposed to the atmosphere. This exothermal reaction is known to cause fires. As such, the nature of the DRI particulates makes the application of a baghouse to be a significant safety hazard and the use of a baghouse for cleaning the process gas is considered technically infeasible.

DRI particulates have high iron content. ESPs are especially sensitive to electrical resistivity, and iron particles adhere very strongly to the ESP collection plates. This makes it difficult to remove the iron particles, which quickly reduces ESP efficiency. Additionally, the application of an ESP creates a significant fire safety hazard when handling the captured DRI particles if exposed to air. The use of an ESP for cleaning the process gas is considered technically infeasible.

As is the case for the use of a baghouse or ESP, the use of a cyclone for removal of DRI particles creates a significant fire safety hazard when handling the captured DRI particles. The use of a cyclone for cleaning the process gas is considered technically infeasible.

The use of a wet scrubber is considered technically feasible because the DRI particulates are collected wet, and do not create a fire safety hazard.

5.4.4 Step 3 – Rank PM/PM10/PM2.5 Control Options

The PM/PM10/PM2.5 control strategies selected for the proposed process reformer that are considered technically feasible are:

- Good combustion practices and use of clean gaseous fuels (i.e., natural gas).
- Venturi scrubber for the process gas prior to combustion.

IU proposes to use the above control strategies to control the emissions of PM/PM10/PM2.5 from the reformer.
5.4.5 Step 4 – Evaluate Feasible PM/PM10/PM2.5 Control Options

The selected PM/PM10/PM2.5 control strategy will not have any material adverse energy, environmental or economic impacts, and therefore it is appropriate that this strategy serve as the basis for establishing the PM/PM10/PM2.5 BACT limits for the reformer exhaust.

5.4.6 Step 5 – Establish PM/PM10/PM2.5 BACT

The use of venturi scrubber for cleaning of top gas, use of gaseous fuel, and use of good combustion practices are the most effective control basis for establishing the PM/PM10/PM2.5 BACT limits from the proposed reformer.

To establish the appropriate BACT limit for the reformer, an analysis of recently established limits in the RBLC and other recent DRI process reformer (that combust process gases from DRI reactors) permits was performed and the results of that analysis are presented in Table 5-4.

<table>
<thead>
<tr>
<th>Facility Name</th>
<th>Permit Limit</th>
<th>Basis</th>
</tr>
</thead>
<tbody>
<tr>
<td>voestalpine Texas LLC</td>
<td>8.06 lb/hour*</td>
<td>0.0044 gr/dscf</td>
</tr>
<tr>
<td>Consolidated Environmental Management</td>
<td>9.95 lb/hour</td>
<td>0.0027 gr/dscf</td>
</tr>
<tr>
<td>(Nucor)**</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

*This limit was later revised to 4.20 lb/hour. It is unclear from the available information why this limit was revised. This limit is not being achieved in practice for this facility.

**Nucor’s operation uses HYL Energiron technology that does not use a reformer.

The stack test data obtained from the voestalpine facility showed that the emissions exceeded the permit limit for this facility. Therefore, this facility is not considered further in this analysis. The Consolidated Environmental Management / Nucor facility was initially proposed with reformer in the 2011 permit issued by Louisiana Department of Environmental Quality (see PSD-LA-751, issued on 1/27/2011, RBLC ID: LA-0248). Subsequently, Nucor switched the project to non-reformer technology that uses a process heater (see PSD-LA-751(M-1)) in place of reformer. Therefore, Nucor project is not considered in the BACT analysis for PM emission from the reformer.

Based on the equipment specification information presented in Appendix C, IU is proposing to establish 0.012 lb/MMBtu (filterable and condensable) as BACT for PM10 and PM2.5 for the reformer. Compliance with this limit will be demonstrated using 40 CFR Part 60, Appendix A, Methods 1 through 4 and Method 5 and 202. For filterable PM, the reformer BACT limit is proposed as 0.005 lb/MMBtu.

Since compliance with numeric particulate matter emissions limits cannot be determined during periods of startup and shutdown, a work practice is proposed as BACT for startup and shutdown of the reformer. Specifically, IU proposes to operate and maintain the reformer unit operation and monitoring equipment in a manner consistent with good air pollution control practices.
5.5 Reformer NOx BACT Analyses

This section presents the required NOx BACT analysis for the proposed reformer main flue ejector stack. NOx emissions from gas-fired combustion reformer result primarily from oxidation of atmospheric nitrogen during the combustion of natural gas. NOx formation is favored when both high combustion temperatures and high excess O2 levels are present. Thermal NOx formation increases exponentially as a function of temperature with the rate of formation rising very rapidly at temperatures above about 2,400 °F. Nitrogen oxide can also be formed when nitrogen in the fuel is present; that is called fuel NOx. Fuel NOx is formed from the direct oxidation of organic nitrogen compounds in the fuel. Fuel organic nitrogen levels will be negligible for natural gas and process gas. As a result, thermal NOx is the primary NOx formation mechanism.

5.5.1 NOx BACT Baseline

No OEPA and federal regulations were identified that limit NOx emissions from the reformer units used for HBI production. For perspective, the NSPS Subpart Ja for forced draft process heaters firing petroleum refinery gas limits nitrogen oxides in excess of 60 parts per million by volume (ppmv), dry basis corrected to 0 percent excess air, on a 7-day rolling average basis. This is equivalent to ~0.06 lb/MBtus at 0 percent excess air. The proposed reformer design includes low-NOx burners with maximum NOx emission rate of 0.06 lb/MBtus.

5.5.2 Step 1 – Identify Available NOx Control Options

A review of the U.S. EPA’s RBLC database and other permit determinations identified the use of low NOx burners (LNB) with and without selective catalytic reduction (SCR), and ultra-low NOx burners (ULNB) with SCR as potentially technically feasible as a technology transfer option for reformer based DRI processes. A summary of the precedents identified from this review and other known permit precedents for reformers is presented in Table 5-5. As a result, the use of LNB, ULNB and SCR controls are considered to be available NOx control options.

Based on a review of recent BACT determinations in various permitting actions, the control strategies (individually and in certain combinations) that can be used to reduce NOx emissions from combustion units include:

- Selective Catalytic Reduction (SCR)
- Selective Non-Catalytic Reduction (SNCR)
- Non-Selective Catalytic Reduction (NSCR)
- EMx (SCONOx)
- Low-Temperature Oxidation (LoTOx)
- Tri-Mer Control Systems
- Low-NO, Burners (LNB)
- Low-NO, Fuel Combustion (LNFC)
- Good Design Methods and Good Operating Practices
## Table 5.5. Summary of NOx Control Precedence for Gas-Fired Reformers

<table>
<thead>
<tr>
<th>RBLC ID/ State</th>
<th>Facility Name</th>
<th>Permit Date</th>
<th>Process Description</th>
<th>Capacity (MMBtu/hr)</th>
<th>Fuel 1</th>
<th>Control 2</th>
<th>Emission Limit lb/MMBtu</th>
</tr>
</thead>
<tbody>
<tr>
<td>LA</td>
<td>Nucor DRI Plant</td>
<td>03/08/2012</td>
<td>Process Gas Heater</td>
<td>923</td>
<td>NG &amp; PG</td>
<td>LNFC, LNB, SCR</td>
<td>0.007</td>
</tr>
<tr>
<td>LA-0248</td>
<td>Nucor DRI Plant</td>
<td>01/27/2011</td>
<td>Reformer*</td>
<td>1389</td>
<td>PG &amp; NG</td>
<td>LNFC, LNB, SCR</td>
<td>0.007</td>
</tr>
<tr>
<td>TX-0650</td>
<td>Voestalpine DRI &amp; HBI</td>
<td>03/18/2014</td>
<td>Gas Reformer</td>
<td>1591</td>
<td>NG</td>
<td>LNB</td>
<td>0.058</td>
</tr>
<tr>
<td>TX-0657</td>
<td>NATGASOLINE Gas to Gasoline</td>
<td>05/16/2014</td>
<td>Reformer*</td>
<td>1552</td>
<td>NG &amp; PG</td>
<td>SCR</td>
<td>0.0087 annual</td>
</tr>
<tr>
<td>TX-0774</td>
<td>Ticona Polymers</td>
<td>11/12/2015</td>
<td>Methanol Reformer</td>
<td>1190</td>
<td>NG</td>
<td>SCR</td>
<td>0.01 annual</td>
</tr>
<tr>
<td>IN-0180</td>
<td>Midwest Fertilizer Iowa Fertilizer</td>
<td>06/04/2014 10/26/2012</td>
<td>Reformer Furnace Primary Reformer</td>
<td>951 1153</td>
<td>NG &amp; PG NG</td>
<td>LNB &amp; SCR</td>
<td>0.0109 (9 ppmv) 30-day</td>
</tr>
<tr>
<td>IN-0180 IA-0105</td>
<td>Northern Plains Nitrogen</td>
<td>08/10/2015</td>
<td>Ammonia Plant Primary Reformer</td>
<td>1006</td>
<td>NG</td>
<td>LNB &amp; SCR</td>
<td>0.0120 30-day</td>
</tr>
<tr>
<td>ND-0033</td>
<td>Eldorado Chemical Co.</td>
<td>11/18/2013</td>
<td>Ammonia Plant Primary Reformer</td>
<td>824</td>
<td>NG</td>
<td>SCR</td>
<td>0.0124 30-day</td>
</tr>
<tr>
<td>AR-0121</td>
<td>Dyno Nobel Louisiana Ammonia</td>
<td>10/08/2012</td>
<td>Ammonia Plant Primary Reformer</td>
<td>956</td>
<td>NG</td>
<td>LNB &amp; SCR</td>
<td>0.0140 Annual</td>
</tr>
<tr>
<td>LA-0272</td>
<td>Air Products and Chemicals</td>
<td>09/04/2012</td>
<td>Hydrogen Plant Reformer</td>
<td>1320</td>
<td>Fuel Gas</td>
<td>ULNB &amp; SCR</td>
<td>0.0150 annual</td>
</tr>
<tr>
<td>ND-0032</td>
<td>CHS Spiritwood Nitrogen Plant</td>
<td>06/20/2014</td>
<td>Primary reformer</td>
<td>788</td>
<td>Fuel Gas</td>
<td>LNB &amp; SCR</td>
<td>0.020 30-day</td>
</tr>
<tr>
<td>AK-0083</td>
<td>Agrium Nitrogen Operations</td>
<td>01/06/2015</td>
<td>Primary Reform Reformer Furnace</td>
<td>1350</td>
<td>NG</td>
<td>SCR</td>
<td>0.025 hourly</td>
</tr>
</tbody>
</table>

* Project was not constructed (not achieved in practice).

1 NG- natural gas, PG- process gas.

2 SCR- selective catalytic reduction, LNB- low NOx burners, ULNB- ultra low NOx burners, LNFC- low NOx fuel combustion.

Each of these control strategies and their “availability” are reviewed in the following subsections.

### 5.5.2.1 Selective Catalytic Reduction (SCR)

SCR is a post-combustion control technology that, for combustion unit applications, typically employs ammonia (NH₃) in the presence of a catalyst to convert NOx to nitrogen and water according to the following overall reactions:

\[
4\text{NH}_3 + 4\text{NO} + \text{O}_2 \rightarrow 4\text{N}_2 + 6\text{H}_2\text{O} \\
4\text{NH}_3 + 2\text{NO}_2 + \text{O}_2 \rightarrow 3\text{N}_2 + 6\text{H}_2\text{O}
\]

An SCR system typically utilizes an injection grid to evenly disperse the NH₃ into the combustion unit exhaust gas upstream of a catalyst. The function of the catalyst is to lower the activation energy of the NH₃-NOx reduction reactions. Operating temperature between 500 °F and 800 °F are required of the gas stream at the catalyst bed. Technical factors related to this...
technology include the catalyst reactor design, optimum operating temperature, sulfur content of the fuel, catalyst deactivation due to aging, ammonia slip (i.e., unreacted NH$_3$ emissions), and the design of the ammonia injection system. Various SCR system designs can remove +80% NOx reduction.

A side-effect of using SCR systems on natural gas fired units is that the SCR catalyst can contribute to condensable particulate matter emissions to the extent the catalyst promotes oxidation of SO$_2$ across the catalyst, thereby producing SO$_3$, which is a condensable particulate. In addition, NH$_3$ slip from the SCR reactor can contribute to the measured mass of particulate matter emissions due to potential for NH$_3$-based reactions to occur in the sampling systems that are typically used to measure condensable particulate matter emissions.

It is important to note, however, that SCR cannot function effectively during startup and shutdown periods when reformer exhaust temperatures are outside the optimum operating window of the catalyst. NH$_3$ is not injected during startup and shutdown conditions to prevent excess NH$_3$ emissions and to avoid potential for damage to the SCR catalyst.

5.5.2.1 Selective Non-Catalytic Reduction (SNCR)

SNCR involves injection of a reducing agent (ammonia or urea) into a gas stream at a temperature window between 1,600 °F and 2,000 °F.$^{31}$ The reducing agent reacts with NOx to form nitrogen and water without the use of a catalyst. Successful application of SNCR requires an injection system capable of mixing the reagent and exhaust gas within the appropriate temperature window and providing sufficient residence time after mixing for the ammonia to react with the NOx. NOx reduction efficiencies achievable with SNCR are lower than those achievable with SCR, typically ranging from 30 to 50 percent for applications with suitable temperature-residence time windows.$^{32}$

5.5.2.2 Non-Selective Catalytic Reduction (NSCR)

NSCR is the exhaust gas treatment technology that is used to control NOx emissions from automobile engines and other reciprocating engines which are operated in a “rich-burn” mode. This technology uses precious metal catalysts, such as platinum, to promote reactions between free radical hydrocarbons, produced by fuel-rich combustion, and NOx. The reaction products are molecular nitrogen (N$_2$) and water.

In a hypothetical application of NSCR, the catalyst modules would have be located in the exhaust gas path downstream of the burners where temperatures are sufficiently high for reaction. The major products of the reactions are molecular nitrogen, carbon dioxide, and water. Application of this technology also requires the installation of downstream oxidation catalysts to remove any unreacted products of the fuel-rich combustion.

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$^{31}$ SNCR is used in this NOx BACT analysis as a generic term that includes specific technologies such as NOXOUT® and Thermal DeNOx™.

$^{32}$ See for example, Air Pollution Control Technology Fact Sheet: Selective Non-Catalytic Reduction, U.S. EPA, EPA-452/F-03-031.
Operating conditions for NSCR require rich-burn fuel to air ratios with less than about 4% oxygen present. As a result, NSCR is only applicable to combustion systems like reciprocating engines, where the combustion process can be tightly controlled in a fuel-rich firing zone. Consequently, NSCR is not applicable to reformer which operate with higher oxygen levels in the exhaust stream. There are no known applications of NSCR to reformer units and there are no suppliers offering this technology for this application. Thus, NSCR is not an “available” technology for reducing NOx emissions from reducing gas fueled reformer and is therefore not considered further in this BACT analysis.

5.5.2.3 EMx™ (SCONOX)

The EMx™ system is an add-on control device that catalytically oxidizes NO to NO₂ and then adsorbs the NO₂ onto a potassium carbonate-coated catalyst surface. The overall chemical reaction between NO₂ and the potassium carbonate catalyst is as follows:

\[ 2 \text{NO}_2 + \text{K}_2\text{CO}_3 \rightarrow \text{CO}_2 + \text{KNO}_2 + \text{KNO}_3 \]

The EMx™ process does not require injection of a reactant, such as ammonia, into the gas stream being treated. EMx™ catalyst is reported to perform acceptably in the operating temperature range of 425 °F to 750 °F with the best economy and lowest pressure drop achieved in the temperature range of 550 °F to 650 °F where the catalyst activity is highest and the catalyst volume is minimized.³³

The EMx™ catalyst has a finite capacity to react with NO₂ because potassium carbonate is “consumed” by NO₂ as shown above. Thus, in order to maintain the required NOx removal rate, the catalyst must be periodically regenerated. Regeneration is accomplished by passing a reducing gas containing hydrogen in dilute concentration (i.e., about 2 to 4 percent H₂) across the surface of the catalyst in the absence of oxygen. Hydrogen in the regeneration gas reacts with the nitrites and nitrates to form water and molecular nitrogen. Carbon dioxide in the regeneration gas reacts with the potassium nitrite and nitrates to regenerate potassium carbonate, which is the original chemical in the catalyst coating. The overall chemical reaction during catalyst regeneration is as follows:

\[ \text{KNO}_2 + \text{KNO}_3 + 4 \text{H}_2 + \text{CO}_2 \rightarrow \text{K}_2\text{CO}_3 + 4 \text{H}_2\text{O} + \text{N}_2 \]

The regeneration gas is produced in a gas generator using a two-stage process to produce molecular hydrogen and carbon dioxide. In the first stage, natural gas and air are reacted across a partial oxidation catalyst to form carbon monoxide and hydrogen. Steam is then added to the mixture and passed across a low temperature shift catalyst, forming carbon dioxide and more hydrogen. The regeneration gas mixture is diluted to less than four percent hydrogen using steam.

In order to regenerate its catalyst, the EMx™ system is constructed in parallel modules so that a module can be isolated from the reformer exhaust gas stream using inlet and outlet dampers. The isolated module is then regenerated while other modules remain open to flow for treatment of the reformer exhaust gas stream.

Sulfur compounds (e.g., SO₂, SO₃) in the gas quickly inactivate the EMx™ catalyst requiring the catalyst to be removed from the reactor for regeneration. To avoid this problem, EMx™ systems on natural gas fueled combustion turbines include an upstream ESx™ catalyst module that removes the sulfur compounds before they reach the EMx™ catalyst beds. The ESx™ catalyst is regenerated at the same time as the EMx™ catalyst by the same regeneration gas. This releases collected SOx as SO₂ into the regeneration off-gas stream.

EMx™ is demonstrated for use on relatively small combined-cycle natural gas fueled combustion turbines. The most recent information from literature survey and vendor indicates that this technology has not been applied to a reformer firing reducing top gas fuel, or other such large combustion chamber units.

5.5.2.4 LoTOx™

The LoTOx™ system injects ozone into the flue gas stream that oxidizes insoluble NOx to soluble oxidized compounds. LoTOx™ is a low temperature system; therefore, it does not require heat input to maintain operational efficiency or to prevent the ‘slip’ of treatment chemicals, such as ammonia, as is common with SCR and SNCR systems. Ozone rapidly reacts with insoluble NO and NO₂ molecules to form soluble N₂O₂. The species N₂O₂ is highly soluble and will rapidly react with moisture in the gas stream to form nitric acid. The conversion of NOx into the aqueous phase in the scrubber is rapid and irreversible, allowing nearly complete removal of NOx. The nitric acid, along with unreacted N₂O₂ and nitrous acid formed by reaction of NO₂ with water, can be easily scrubbed out of the gas stream in a wet scrubber with water or neutralized with a caustic solution.

5.5.2.5 Tri-Mer

The Tri-Mer catalytic baghouse technology has been established as BACT in several PSD permits; however, these facilities have not begun operation. Thus, while a catalytic baghouse system could be considered, it is important to note that the technology is relatively new and does not have an established operating track record (e.g., initial compliance demonstrations, actual operating costs, demonstrated life of catalytic bags, etc.). Further, a Tri-Mer system has not been installed on a reformer and is not considered “available” and is therefore not considered further in this BACT analysis.

5.5.2.6 Low NOx Burners (LNB)

Since early 1970s LNBs have been used for thermal NOx control. These specially designed burners employ low excess air (LEA), off-stoichiometric (or staged) combustion (OSC), and flue gas recirculation (FGR) to control NOx formation. The objective in the application of LNBs is to minimize NOx formation while maintaining acceptable combustion of carbon and hydrogen in the fuel.
LNB and a burner featuring LEA or FGR may not appear that much different. In general, LNBs implement LEA, OSC, FGR, or a combination of these techniques. In a stricter sense, LNBs have been defined as burners that control NOx formation by carrying out the combustion in stages (OSC) and, further, by controlling the staging at and within the burner rather than in the firebox.

Consistent with this definition, there are two distinct types of designs for LNBs: staged air burners; and staged fuel burners. Staged air burners are designed to reduce flame turbulence, delay fuel/air mixing, and establish fuel-rich zones for initial combustion. The reduced availability of oxygen in the initial combustion zone inhibits fuel NOx conversion. Radiation of heat from the primary combustion zone results in reduced temperature as the final unburned fuel gases mix with excess air to complete the combustion process. The longer, less intense flames resulting from the staged stoichiometry lower peak flame temperatures and reduce thermal NOx formation. The proposed reformer is to be equipped with LNB with NOx emission no greater than 0.06 lb/MMBtu corrected to 3% O2. This constitutes the baseline for NOx BACT determination for the reformer.

5.5.2.7 Low-NOx, Fuel Combustion (LNFC)

A low-NOx fuel is one which results in a lower generation rate of NOx over traditional fossil fuels, on an equal energy basis. DRI top gas is a low-NOx fuel, generating less than half of the NOx per unit of energy as natural gas. This property is due to the low-BTU value of top gas, which burns at a cooler temperature, preventing the formation of a majority of the thermal NOx seen with natural gas combustion.

5.5.2.8 Good Design Methods and Good Operating Practices

Good design includes process and mechanical equipment designs which are either inherently lower polluting or are designed to minimize emissions. Good operating practices include operating methods, procedures and selection of raw materials to minimize emissions.

5.5.3 Step 2 – Eliminate Technically Infeasible NOx Control Options

Of the potentially available NOx control options identified in Step 1, the following are considered to be technically infeasible as discussed below.

5.5.3.1 SNCR is Technically Infeasible

Because the exhaust temperatures from the proposed reformer will not approach the appropriate operating temperature window for SNCR, this technology is not technically feasible for application to the proposed unit. The maximum reformer exhaust temperatures are expected to be less than 1,200 °F which is well below the range at which SNCR is effective.

5.5.3.2 EMx™ is Technically Infeasible

EMx™ is infeasible because it has not been demonstrated on any reducing top gas fired reformer unit. While it is theoretically possible to consider an air dilution cooling system similar to those used for combustion turbine SCR applications, the volume of dilution air needed to achieve an EMx™-compatible exhaust temperature exceeds any previous application of this technology by nearly a factor of two.
5.5.3.1 LoTOx™ is Technically Infeasible

Although a prior BACT determination for a DRI plant included a requirement for the trial of LoTOx™ technology, this technology is yet to be demonstrated in practice. Therefore, this technology is considered technically infeasible for control of NOx from the proposed reformer.\(^3^4\)

5.5.3.1 SCR Technically Feasibility on Reformer is Unknown

A prior determination, for the Nucor DRI plant in Louisiana, included a requirement to use SCR to control NOx emissions from the process heater in the operation. However, the Nucor facility uses tenova HYL/ENERGIRON ZR vendor supplied DRI technology that uses a process heater to simply heat the gas (there is no gas reforming in that step).\(^3^5\) IU is proposing to use the MIDREX supplied DRI technology that uses a separate reformer unit in place of a process heater to supply the reformed gas to the shaft furnace.\(^3^6\) Of the nearly 60 installations using MIDREX DRI technology worldwide, none use an SCR to control NOx emissions from the reformer unit. Therefore, so far the SCR technology has not been demonstrated in practice for a reformer unit in a DRI application. Although, SCR is not technically feasible for the MIDREX reformer application, IU conservatively did not reject it in step 2 and instead carried it through rest of the NOx BACT analysis for the reformer.

5.5.4 Step 3 – Rank NOx Control Options

Table 5-6 lists the feasible NOx control options in descending order of effectiveness. The top performing feasible control option is a combination of LNB and SCR. LNB alone is less effective options. Good design methods and good operating practices as well as LNFC are considered integral to the reformer design and operation.

<table>
<thead>
<tr>
<th>Control Strategy</th>
<th>NOx BACT Level</th>
<th>Control Efficiency</th>
</tr>
</thead>
<tbody>
<tr>
<td>SCR + LNB</td>
<td>0.009 lb/MMBtu</td>
<td>85%*</td>
</tr>
<tr>
<td>LNB</td>
<td>0.06 lb/MMBtu</td>
<td>-</td>
</tr>
</tbody>
</table>

*Conservative assumption - No data is available for top gas (low heating value) combustion

5.5.5 Step 4 – Evaluate Feasible NOx Control Options

Use of LNB represents the baseline NOx emission rate for the proposed reformer. The technical feasibility of SCR for the reformer is unknown. This subsection documents the energy, environmental, and economic impacts associated with applying SCR to the proposed reformer in the event it is later determined to be technically feasible for the MIDREX process.

\(^3^4\) The trial application was for an indurating furnace at the Essar Steel’s proposed Minnesota Steel Industries, LLC facility. See: https://www.pca.state.mn.us/sites/default/files/06100067-001-aqpermit.pdf. This project is yet to be completed.

\(^3^5\) Information from tenova website: http://www.tenova.com/product/iron-reduction-technologies/ (last accessed on September 1, 2017).

\(^3^6\) Information from MIDREX website: http://www.midrex.com/assets/user/media/MIDREX_NG.pdf (last accessed on September 1, 2017).

\(^3^7\) All values are at 3% O\(_2\).
**Environmental Impacts:** The spent catalyst must be disposed following normal waste procedures. The catalyst is often disposed of by the manufacturer. The increased fan electric power due to the pressure drop across the catalyst increases the emission rate of other criteria pollutants, such as PM, NOx, CO, and GHGs wherever the power is generated. There is additional fuel penalty associated with loss of thermal efficiency due to need for dilution air that lowers convection section heat recovery. Additionally, if an ammonia reagent is used there are risks associated with storage, shipping and handling and fugitive ammonia emissions from equipment leaks.

As previously noted, the application of SCR comes with other environmental impacts. The combustion of sulfur in fuels produces SO\(_2\) and SO\(_3\) emissions during the combustion process. Additional SO\(_3\) is formed as the SO\(_2\) in the flue gas passes through the SCR catalyst bed. The SO\(_3\) then reacts with unreacted ammonia (i.e., slip ammonia) to form ammonium sulfate [(NH\(_4\)_\(_2\))SO\(_4\)] and ammonium bisulfate (NH\(_4\)HSO\(_4\)) salts, which are emitted as fine particulates. Since the natural gas and process gas have low sulfur content, the emissions of this additional fine particulate (PM10/PM2.5) are however, expected to be minimal.

**Economic Impacts:** Economic impacts from use of SCR and LNB are shown in Table 5-7. This estimate uses the calculation methodology based on various U.S. EPA documents noted in Appendix D.

**Table 5-7. NOx BACT Control Technology Economic Impact Analysis**

<table>
<thead>
<tr>
<th>Parameter</th>
<th>SCR*</th>
</tr>
</thead>
<tbody>
<tr>
<td>Heat Input (MMBtu/hr HHV)</td>
<td>1,687</td>
</tr>
<tr>
<td>NOx Emissions Control</td>
<td></td>
</tr>
<tr>
<td>SCR Inlet NOx lb/MMBtu:</td>
<td>0.06</td>
</tr>
<tr>
<td>SCR Outlet NOx lb/MMBtu:</td>
<td>0.009</td>
</tr>
<tr>
<td>Tons per Year NOx Emissions w/o SCR:</td>
<td>436.9</td>
</tr>
<tr>
<td>Tons per Year NOx Emissions with SCR:</td>
<td>65.5</td>
</tr>
<tr>
<td>Tons per Year NOx Reduction:</td>
<td>371.4</td>
</tr>
<tr>
<td>Economic Impacts</td>
<td></td>
</tr>
<tr>
<td>Total Capital Requirement:</td>
<td>$24,404,599</td>
</tr>
<tr>
<td>Annual O&amp;M Costs:</td>
<td>$2,778,522</td>
</tr>
<tr>
<td>Capital Recovery Cost + Insurance &amp; Administration:</td>
<td>$3,035,759</td>
</tr>
<tr>
<td>Total Annual Costs:</td>
<td>$5,814,281</td>
</tr>
<tr>
<td>SCR NOx Reduction Cost Effectiveness:</td>
<td>$15,656</td>
</tr>
</tbody>
</table>

* LNB, LNFC and Good Design and Operation assumed baseline here.
The capital cost associated with the installation of an SCR is estimated to be $24.4 million. The capital cost of the SCR includes the catalyst; catalyst housing, ammonia tank and ejection system, flue gas path modifications; and balance of plant equipment. Capital costs were escalated from 2013 to 2017 dollars using the Consumer Price Index. An equipment life of 20 years and an interest rate of 7 percent were assumed resulting in a capital recovery factor of 0.094. Since there is no track record of SCR application for a DRI reformer, a more realistic estimate for the equipment life is 10 to 15 years.

The annual operating cost associated with the SCR system is approximately $2.7 million per year. The annual operating costs include catalyst replacement, energy impacts, and maintenance. A catalyst life of three years is assumed with SCR NOx control efficiency of 85%. The resultant cost effectiveness associated with the use of SCR is $15,656 per ton of NOx removed for the LNB+SCR option conservatively assuming a 20 year equipment life. The cost effectiveness will be even higher if a shorter equipment life is used in the analysis as reflective of more real world application of this untested control for the reformer. Use of SCR is rejected as BACT, in part, on the unreasonable, adverse economic impacts that would be associated with use of this control option for the reformer. This cost is above the range of cost effectiveness values considered to be reasonable or acceptable in BACT determinations for control of NOx emissions. For example, San Joaquin Valley District in California uses a NOx cost effectiveness threshold of $9,700 per ton removed.

Detailed cost effectiveness analysis calculations for use of a SCR for NOx emissions from the reformer are provided in Appendix D.

Energy Impacts: Use of SCR results in fuel penalty for the reformer operation due to loss of heat transfer efficiency in the preheat section. Also, a larger horsepower motor for the fan will be needed due to the increased pressure drop across the unit, thereby also increasing the electricity usage.

5.5.6 Step 5 – Establish NOx BACT

Based on the above analysis, use of LNB and good operating practices is deemed BACT for NOx from the proposed reformer unit. The application of SCR is not proposed due to environmental impacts, high capital costs, annual cost, and cost effectiveness. IU proposes a NOx emission limit and monitoring conditions noted below:

- 0.06 lb/MMBtu on 30-day rolling average basis based on use of LNB, and
- Use of annual performance tests along with monitoring of the reformer’s operating parameters in accordance with the good operating practices requirements established by the equipment vendor.

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38 SCR cost information from the voestalpine HBI/DRI facility PSD permit application submitted to Texas Commission on Environmental Quality, August 2013.
5.6 Reformer CO BACT Analysis

This section presents the required CO BACT analysis for the proposed reformer. CO is emitted from the reformer as a result of incomplete combustion of top gas and natural gas. Therefore, the most direct approach for reducing these emissions is to maximize combustion efficiency in the reformer. High combustion temperatures, adequate excess air, and good air/fuel mixing during combustion minimize CO emissions. Measures taken to minimize the formation of NOx during combustion may inhibit complete combustion, which can increase CO emissions. Lowering combustion temperatures through staged-combustion to reduce NOx emissions can be counterproductive with regard to CO emissions. However, the improved air/fuel mixing that is inherent in newer LNB designs and control systems help overcome the impact of fuel and/or air staging on CO emissions.

5.6.1 CO BACT Baseline

There are no state, local or federal regulations applicable to CO emissions from the proposed reformer. Therefore there is no “BACT baseline” for CO.

5.6.2 Steps 1 and 2 – Identify Available and Feasible CO Control Options

Based on a review of recent reformer BACT determinations in U.S. EPA’s RBLC database and other literature survey, the control strategies (individually and in certain combinations) that are being used to limit CO emissions from combustion units include:

- Good Combustion Practices; and
- Oxidation Catalysts.

Oxidation catalysts have previously been applied to natural gas fired boilers located in CO and/or ozone nonattainment areas, but are primarily used on large combustion turbines. The oxidation catalyst is typically a precious metal catalyst (e.g., platinum) that has been applied over a metal or ceramic substrate. The catalyst lowers the activation energy for the oxidation of CO so that it is oxidized at lower temperatures (optimum range of 850 - 1,100 °F) than seen in the furnace (i.e., combustion zone). The CO removal efficiency in natural gas fired systems is typically greater than 90 percent. The reformer flue gas temperature is expected to be around 600 °F. This is below the optimum temperature for good oxidation catalyst operation. As such, the flue gas would need to be reheated, or the catalyst would have to be inserted before the air preheater.

Good combustion practices, as the name implies, are based upon maintaining good fuel/air mixing, a proper fuel/air ratio, and adequate time at the required combustion temperature. The CO emission limits, identified in the RBLC database, range from 0.0194 to 0.078 lb/MMBtu.

A summary of the precedents identified from RBLC review and other known permit precedents for reformers is presented in Table 5-8.
### Table 5-8. Summary of CO BACT Precedence for Gas-Fired Reformers

<table>
<thead>
<tr>
<th>RBLC ID/ State</th>
<th>Facility Name ¹</th>
<th>Permit Date</th>
<th>Process Description</th>
<th>Capacity (MMBtu/hr)</th>
<th>Fuel ²</th>
<th>Control ³</th>
<th>Emission Limit lb/MMBtu</th>
</tr>
</thead>
<tbody>
<tr>
<td>AR-0121</td>
<td>Eldorado Chemical Co.</td>
<td>11/18/2013</td>
<td>Ammonia Plant Primary Reformer</td>
<td>824</td>
<td>NG</td>
<td>GCP</td>
<td>0.0114 Rolling 3-hour</td>
</tr>
<tr>
<td>ND-0033</td>
<td>Northern Plains Nitrogen</td>
<td>08/10/2015</td>
<td>Ammonia Plant Primary Reformer</td>
<td>1153</td>
<td>NG</td>
<td>GCP</td>
<td>0.0194 Stack test</td>
</tr>
<tr>
<td>IA-0105</td>
<td>Iowa Fertilizer</td>
<td>10/26/2012</td>
<td>Primary Reformer</td>
<td>1006</td>
<td>NG</td>
<td>GCP</td>
<td>0.0194 Stack test</td>
</tr>
<tr>
<td>ND-0032</td>
<td>CHS Spiritwood Nitrogen Plant</td>
<td>06/20/2014</td>
<td>Primary reformer</td>
<td>788</td>
<td>Fuel Gas</td>
<td>GCP</td>
<td>0.021 Rolling 30-day</td>
</tr>
<tr>
<td>TX-0657</td>
<td>NATGASOLINE Gas to Gasoline</td>
<td>05/16/2014</td>
<td>Reformer</td>
<td>1552</td>
<td>NG &amp; PG</td>
<td>GCP</td>
<td>0.037 annual</td>
</tr>
<tr>
<td>TX-0774</td>
<td>Ticona Polymers</td>
<td>11/12/2015</td>
<td>Methanol Reformer</td>
<td>1190</td>
<td>NG</td>
<td>GCP</td>
<td>0.037 annual</td>
</tr>
<tr>
<td>LA</td>
<td>Nucor DRI Plant</td>
<td>03/08/2012</td>
<td>Process Gas Heater</td>
<td>923</td>
<td>NG &amp; PG</td>
<td>GCP</td>
<td>0.040</td>
</tr>
<tr>
<td>LA-0248</td>
<td>Nucor DRI Plant</td>
<td>01/27/2011</td>
<td>Reformer</td>
<td>1389</td>
<td>Iron ore &amp; NG</td>
<td>GCP</td>
<td>0.040</td>
</tr>
<tr>
<td>AK-0083</td>
<td>Agrium Nitrogen Operations</td>
<td>01/06/2015</td>
<td>Primary Reformer Furnace</td>
<td>1350</td>
<td>NG</td>
<td>None specified</td>
<td>0.0430 3-hour</td>
</tr>
<tr>
<td>IN-0180</td>
<td>Midwest Fertilizer</td>
<td>06/04/2014</td>
<td>Reformer Furnace</td>
<td>951</td>
<td>NG &amp; PG</td>
<td>GCP</td>
<td>0.0457 Stack test</td>
</tr>
<tr>
<td>LA-0272</td>
<td>Dyno Nobel Louisiana Ammonia</td>
<td>10/08/2012</td>
<td>Ammonia Plant Primary Reformer</td>
<td>956</td>
<td>NG</td>
<td>GCP</td>
<td>0.0514 1-hour</td>
</tr>
<tr>
<td>TX-0650</td>
<td>Voestalpine DRI &amp; HB</td>
<td>03/18/2014</td>
<td>Gas Reformer</td>
<td>1591</td>
<td>NG</td>
<td>GCP</td>
<td>0.078</td>
</tr>
</tbody>
</table>

1 - Selected facilities shown for a range of permits.
2 - NG – Natural Gas, PG – Process Gas.
3 - GCP – Good combustion practices, design, and operation.

#### 5.6.3  Step 3 – Rank CO Control Options

Good combustion practices (GCP) is considered the baseline control technology for CO emissions. The addition of an oxidation catalyst to reduce outlet emissions of CO is evaluated in Step 4. For BACT impact analysis basis, an emission rate of 0.031 lb/MMBtu was used. This rate provided by the vendor falls within the high and low values identified in Table 5-8. The BACT evaluation that follows considered the energy, environmental, and economic impacts of oxidation catalyst relative to good combustion practices.

#### 5.6.4  Step 4 – Evaluate Feasible CO Control Options

This subsection documents the energy, environmental, and economic impacts associated with applying oxidation catalyst to the proposed reformer.

**Economic Impacts:** A summary of the impacts analysis for use of an oxidation catalyst for the reformer is presented in Table 5-9. The costs were estimated using U.S. EPA’s COST-AIR
spreadsheet for catalytic oxidation.\textsuperscript{40} Capital costs were escalated to 2017 dollars using the Consumer Price Index.

\begin{table}[h]
\centering
\caption{CO BACT Control Technology Economic Impact Analysis}
\begin{tabular}{|l|c|}
\hline
Parameter & Oxidation Catalyst* \\
\hline
Heat Input (MMBtu/hr HHV) & 1,687 \\
\hline
CO Emissions Control & \\
Oxidation Catalyst (OC) Inlet CO lb/MMBtu: & 0.031 \\
OC Outlet CO lb/MMBtu: & 0.0031 \\
Tons per Year CO Emissions w/o OC: & 229.1 \\
Tons per Year CO Emissions with OC: & 22.9 \\
Tons per Year CO Reduction: & 206.2 \\
\hline
Economic Impacts & \\
Total Capital Requirement: & $2,411,046 \\
Annual O&M Costs: & $678,317 \\
Capital Recovery Cost + Overhead + Taxes: & $188,400 \\
Total Annual Costs: & $866,717 \\
OC CO Reduction Cost Effectiveness: & $4,204 \\
\hline
\end{tabular}
\footnote{\textit{Good combustion practices assumed baseline here.}}
\end{table}

The capital cost associated with the installation of an oxidation catalyst is estimated to be $1.8 million. The capital cost of the oxidation catalyst system includes the catalyst; catalyst housing, economizer modifications; and balance of plant equipment. Capital costs were escalated to 2017 dollars using the Consumer Price Index. An equipment life of 20 years and an interest rate of 7 percent were assumed resulting in a capital recovery factor of 0.094.

The annual operating cost associated with the oxidation catalyst system is approximately $515,000 per year. The annual operating costs include capital recovery,\textsuperscript{41} catalyst replacement, energy impacts, operating personnel, and maintenance. A catalyst life of five years is assumed. The resultant cost effectiveness associated with the use of oxidation catalyst is $4,204 per ton of CO removed. Detailed emissions calculations for the oxidation catalyst control of the reformer emissions are provided in Appendix D.

\textsuperscript{40} \textit{COST-AIR Control Cost Spreadsheets, Second Edition, USEPA, July 1999.}
\textsuperscript{41} Standard USEPA capital recovery factor of 0.09 based on 20 year control system life and 7 percent cost of money.
**Environmental Impacts:** The spent catalyst is comprised of precious metals that are not considered toxic. This allows the catalyst to be handled and disposed of following normal waste procedures. Because of its precious metal content, the catalyst is often recycled by the manufacturer to recover the metals. The increased fan electric power due to the pressure drop across the catalyst increases the emission rate of other criteria pollutants, such as PM, NOx, CO, and GHGs wherever the power is generated.

**5.6.5 Step 5 – Establish CO BACT**

Installation of the oxidation catalyst will have negative energy, environmental, and economic impacts. In summary, the catalyst would increase the pressure drop through the reformer, resulting in increased electrical demand on the draft fans. The increased electrical demand will result in an increase in fuel consumption to provide electricity resulting in increased pollutant emissions (negative energy and environmental impacts). The negative economic impacts include the increased capital cost for the installation of the oxidation catalyst system, and increased operating cost due to periodic replacement of the catalyst.

Based on the energy, environmental, and economic (over $4,000 dollars per ton) impacts, the installation of oxidation catalyst is eliminated from consideration as BACT for CO emissions for the proposed reformer. IU proposes a CO emission limit and testing requirements of

- 0.031 lb/MMBtu on 30-day rolling average basis based on the use of good combustion practices, and
- Use of annual performance tests along with monitoring of the reformer’s operating parameters in accordance with the good operating practices requirements established by the equipment vendor.

**5.7 Reformer GHG BACT Analysis**

Producing steel using HBI requires significantly less energy, and generates 50% lower greenhouse gas emissions, compared to traditional steelmaking.\(^42\) Thus, this Project will have a beneficial effect on GHG emissions in the industry. Also, this Project is designed to use top gas and heat recovery to reduce fossil fuel consumption and increase energy efficiency. The following analysis looks at whether any additional controls for GHG emissions are technically feasible, available and cost effective under the BACT procedures.

Natural gas feedstock is heated and reformed in the reformer at an elevated temperature to produce reducing gas consisting mainly of CO and H\(_2\). The elevated temperature results in dissociation of natural gas into CO and H\(_2\) that are primary reductants in the DRI reactor.

\[
\begin{align*}
\text{CH}_4 + \text{CO}_2 & \rightarrow 2 \text{CO} + 2 \text{H}_2 \\
\text{CH}_4 + \text{H}_2\text{O} & \rightarrow \text{CO} + 3 \text{H}_2
\end{align*}
\]

\(^42\) Statement of Basis for Permit Number: PSD-TX-1344-GHG (voestalpine LLC Texas LLC), U.S. EPA, Region 6, April 24, 2014, page 15.
Reducing gas (CO and H₂) are produced in the reformer that has proprietary tubular design. Heat for the reforming reaction in the reformer is supplied by floor-fired main burners, which are located on the bottom of the reformer box between tube rows and between tube rows and outside wall. Main burners use top gas with supplemental natural gas as fuel. The air required for combustion is preheated in the heat recovery system before being directed to the burners with the main air blower. Natural gas-fired auxiliary burners maintain the reformer box temperature during plant idle conditions to reduce restart time and thermal cycling of the reformer tubes.

The spent reducing gas exit from the top of the DRI reactor for recycle to the reformer after undergoing cleaning and cooling in the system. CO₂ in the top gas simply passes through the combustion process as an inert. DRI process design releases CO₂ from the process gas loop by off-taking a stream of spent reducing gas for use as fuel in the reformer burners. After cleaning and cooling of the spent reducing gas (top gas), about one-third of the gas is mixed with small amount of natural gas and passes through a mist eliminator to remove droplets to become the fuel mixture for the reformer main burners. This setup serves to both allow for an outlet for CO₂ from the process gas and increases energy efficiency of the reformer through energy integration. While this arrangement increases the energy efficiency by providing more gases to surround the reformer tubes for heat transfer, CO₂ along with other products of combustion are ultimately released to the atmosphere. CO₂ emissions in the reformer exhaust are mixed with other products of combustion including nitrogen and are not suitable for underground sequestration.

GHG emissions from the proposed top gas and natural gas-fired reformer include carbon dioxide (CO₂), methane (CH₄), and nitrous oxide (N₂O). CO₂ emissions result from complete combustion while CH₄ emissions result from incomplete combustion of the gaseous fuel. Methane emissions may also result from natural gas fuel leaks which may occur from valves and piping, and during maintenance activities. Nitrous oxide (N₂O) emissions are formed in trace quantities during combustion and are minimized when combustion temperature are lower and excess oxygen is low.

Under PSD applicability, GHGs emissions are addressed as carbon dioxide equivalent (“CO₂e”) emissions that are calculated using the global warming potentials (GWP) for the various GHGs. The GWP of CO₂ is set at 1, CH₄ at 25, and N₂O at 298. CO₂e emissions are calculated by multiplying the emission rates of each of the GHGs with its GWP which are then summed to compute the total GHG emissions for a unit.

Based on the emission factors for GHGs, CO₂ emissions account for 99.9% of the total GHG emissions. Because CO₂ emissions account for the vast majority of GHG emissions from the proposed reformer, this BACT analysis focuses primarily on control strategies that limit CO₂ emissions.

5.7.1 GHGs BACT Baseline

No applicable GHG standards have been promulgated for reformer under 40 CFR parts 60 and 61, or under OEPA or federal regulations.
5.7.2 Step 1 – Identify Available CO₂ Control Options

A combination of published resources and general knowledge of industry practices was used to generate the list of potential controls for reformer GHG emissions presented in the Table 5-10. For the proposed reformer, there are three broad strategies for reducing GHG emissions:

- Use of low carbon fuels,
- Energy integration,
- Maximized combustion efficiency, and
- Carbon capture and sequestration (CCS).

A description of these strategies is presented below.

**Table 5-10. Summary of GHG BACT Precedence for DRI Plants**

<table>
<thead>
<tr>
<th>RBLC ID or State</th>
<th>Company Name/Location</th>
<th>Permit Date</th>
<th>Process Description</th>
<th>Control Technology</th>
<th>BACT Limits</th>
</tr>
</thead>
<tbody>
<tr>
<td>LA-0248</td>
<td>Consolidated Environmental Management Inc. – Nucor St. James, LA</td>
<td>01/27/2011</td>
<td>Reformer Main Flue Stack (DRI-108 – DRI Unit #1)</td>
<td>Good combustion practices, acid gas separation system, energy integration.</td>
<td>No more than 13 decatherms of natural gas per tonne of DRI (11.79 MMBtu/ton of DRI).</td>
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<tr>
<td></td>
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<td></td>
<td>Reformer Main Flue Stack (DRI-208 – DRI Unit #2)</td>
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<td></td>
<td></td>
<td></td>
<td>Package Boiler (DRI-109)</td>
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<td></td>
<td></td>
<td></td>
<td>Package Boiler (DRI-209)</td>
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<tr>
<td>Louisiana</td>
<td>Consolidated Environmental Management Inc. – Nucor St. James, LA</td>
<td>07/19/2012</td>
<td>Process Heater (to replace Reformer) (DRI-108 – DRI Unit #1)</td>
<td>Good combustion practices, acid gas separation system, energy integration.</td>
<td>No more than 13 decatherms of natural gas per tonne of DRI (11.79 MMBtu/ton of DRI).</td>
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<tr>
<td>Texas</td>
<td>Voestalpine Texas LLC</td>
<td>06/13/2014</td>
<td>Site wide</td>
<td>Limit natural gas use to no more than 13 decatherms/tonne HBI (11.79 MMBtu/ton HBI) 12-month rolling annual average.</td>
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<tr>
<td></td>
<td>Corpus Christi, Tx</td>
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<td></td>
<td></td>
<td></td>
<td>Reformer Main Flue Ejector Stack</td>
<td>Energy efficient equipment. Enhanced Process Control. Natural gas for fuels and process gas raw material Heat recovery and energy integration</td>
<td>1,683,316 TPY 12 month rolling average</td>
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<td></td>
<td>Hot Pressure Relief Vent Flare</td>
<td>Natural gas for pilot. Good combustion practices, design, operate, and maintain consistent with 40 CFR §60.18.</td>
<td>2,462 TPY 12 month rolling average</td>
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<td></td>
<td>Charge Hopper</td>
<td>Enhanced process control. Heat recovery and energy integration.</td>
<td>54,802 TPY 12 month rolling average</td>
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<td></td>
<td></td>
<td></td>
<td>Bottom Seal Gas Wet Scrubber</td>
<td>Enhanced process control. Heat recovery and energy integration.</td>
<td>54,802 TPY 12 month rolling average</td>
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<tr>
<td></td>
<td></td>
<td></td>
<td>Briquetter Dedusting</td>
<td>Enhanced process control. Heat recovery and energy integration.</td>
<td>27,403 TPY 12 month rolling average</td>
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<tr>
<td></td>
<td></td>
<td></td>
<td>Process Water Degasser</td>
<td>Enhanced process control (good operating practices and proper maintenance).</td>
<td>1,636 TPY 12 month rolling average</td>
</tr>
</tbody>
</table>
5.7.2.1 Use of Lower Carbon Fuels

As shown in Table 5-11, relative to other types of fuels, the use of natural gas yields lower combustion emissions of GHGs collectively and each greenhouse gas individually when compared to other types of generally available fuels. Thus, combustion GHG emissions are minimized by maximizing the combustion of natural gas. This GHG reduction measure is inherent in the design of the proposed Project because natural gas is the only external fuel that will be used in the proposed HBI process.

**Table 5-11. GHG Emission Factors for Various Fuels**

<table>
<thead>
<tr>
<th>Fuel</th>
<th>Emission Factor (lb/MMBtu)*</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>CH4</td>
</tr>
<tr>
<td>Petroleum Coke</td>
<td>0.024</td>
</tr>
<tr>
<td>Subbituminous Coal</td>
<td>0.024</td>
</tr>
<tr>
<td>Residual Oil (No. 6)</td>
<td>0.007</td>
</tr>
<tr>
<td>Crude Oil</td>
<td>0.007</td>
</tr>
<tr>
<td>Distillate Oil (No. 2)</td>
<td>0.007</td>
</tr>
<tr>
<td>Natural Gas</td>
<td>0.002</td>
</tr>
</tbody>
</table>

* Individual GHG emissions factors are from Tables C-1 and C-2 of 40 CFR 98, subpart C. The CO2e factor is computed using the GWP of individual GHGs.

5.7.2.1 Energy Integration

Decreased natural gas usage is the primary method of reducing combustion related GHG emissions for the HBI process. Energy integration by reducing wasted energy as much as possible reduces fuel consumption. The proposed DRI process design includes the use of reducing gas or top gas from the DRI reactor as fuel for the reformer. Top gas is mainly CO and H2 with residual fuel value for use in combustion systems. The top gas is mixed with the natural gas, replacing a portion of the needed heat input to the reformer. This design integrates the energy cycle of the process in order to capture as much residual energy from the DRI reactor gases as possible.

5.7.2.2 Maximized Combustion Efficiency

Fuel consumption can also be reduced by maximizing combustion efficiency by optimizing the quantity of usable energy transferred from the fuel to the process. Combustion efficiency is maximized by optimizing the following in the combustion zone:

- Air to fuel ratio
- Fuel temperature
- Combustion zone pressure
- Heat transfer area

5.7.2.3 Carbon Capture and Sequestration

The final control strategy that is potentially available for reducing GHG emissions from the reformer exhaust involves capturing CO2 and “permanently” storing it. While the CCS concept is
currently receiving significant attention as a GHG control strategy, it is clearly still in the R&D (research and development) phase and not truly an available technology. Nevertheless, for purposes of completeness, this BACT analysis addresses the CCS process in Steps 2 through 4.

The CCS process involves three main steps:

- Capturing and concentrating CO₂ at its source by separating it from other constituents in the reformer exhaust gas stream;
- Transporting the captured CO₂ to a suitable storage location, typically in compressed/liquid form; and
- Storing the CO₂ away from the atmosphere for a long period of time, for instance in underground geological formations or in the deep ocean.

In a conventional combustion device, the oxygen required for combustion of fuel is provided by air. Because air contains about 79 percent nitrogen, the CO₂ concentration in the exhaust gas stream from the reformer is necessarily diluted by the inert nitrogen and excess oxygen along with other products of combustion. The average CO₂ concentration in the exhaust gas from the reformer will be on the order of 5 volume percent. Therefore, capture and concentration of CO₂ is an important element of any CCS strategy that would be applied to the proposed reformer.

Capture and/or concentration of CO₂ from a combustion source can theoretically be achieved either through pre-combustion methods or through post-combustion methods. The availability of each of these techniques for application to the proposed Project is discussed below.

5.7.2.3.1 Pre-Combustion CO₂ Concentration

For some combustion units, one option that can be used to increase the CO₂ concentration in the exhaust gas stream is to use oxygen instead of air to combust the fuel (i.e., oxy-combustion). This technique results in a more concentrated CO₂ exhaust gas stream with the combustion exhaust gases containing primarily CO₂, H₂O and O₂. This stream would still need to be further processed to produce a relatively pure stream suitable for transportation and storage, but the size, costs and complexity of downstream processing equipment are significantly reduced relative to the equipment required if air is used in the combustion step.

Direct use of oxygen for combustion is not an available option for increasing the exhaust gas CO₂ concentration in the reformer planned for the Project. This technology has not been demonstrated for reformers at DRI plants.

5.7.2.3.2 CO₂ Capture Using Post-Combustion Techniques

Post-combustion CO₂ capture methods can, in theory, be applied to conventional combustion systems that use air and carbon-containing fuels in the combustion process. Technologies that might be applied for post-combustion CO₂ capture are described below.

Absorption of the CO₂ with chemical solvents such as amines: This is currently the most common method being evaluated for CO₂ capture from combustion stack gases. This process is illustrated in Figure 5-1. Monoethanolamine (MEA) solvent has the advantage of fast reaction with CO₂ at the relatively low partial pressures found in most combustion exhaust gases. Some of the main concerns with MEA and other amine solvents are: corrosion due to the presence of
O₂ and other impurities in the exhaust gas, high solvent degradation rates because of solvent irreversible reactions with SO₂ and NOx, and the large amount of energy required for solvent regeneration. Although this technology has not been commercially demonstrated with gas-fired combustion units similar to the proposed reformer, it is conservatively assumed to be an “available technology” for the purposes of this GHG BACT analysis because it can theoretically be applied to a reformer without affecting the design.

One notable aspect of the capture and concentration process illustrated in Figure 5-1 is that significant amounts of steam are required by the process in the solvent regeneration step. For the proposed Project, this increased steam demand would require the construction of a new steam generator (e.g., a new gas-fired boiler) as part of the Project specifically for the purpose of regenerating the spent MEA solvent. Generation of this steam will result in additional emissions including a considerable quantity of GHGs as well as lesser amounts of NOx, CO, particulate matter, and other pollutants.

![Figure 5-1. Simplified PFD of a Combustion CO₂ Capture and Concentration System](image)

**Calcium cycle separation**: In theory, quicklime (i.e., CaO) can be used to capture CO₂ yielding limestone, which can then be heated, releasing the captured CO₂ in a concentrated stream and regenerating the quicklime for reuse. R&D work is still required to obtain adequate sorbent stability after regeneration. As such, this technique is not considered an “available” CO₂ capture and concentration technology for purposes of this BACT analysis.
Cryogenic separation: This technique is based on solidifying CO\textsubscript{2} by frosting it to separate it from other gaseous components in the exhaust gas stream. However, the low concentration of CO\textsubscript{2} in the exhaust gas from conventional air-based combustion processes renders this technology impractical. As such, this technique is not considered an “available technology” for purposes of this BACT analysis.

Membrane separation: This technique is commonly used for CO\textsubscript{2} removal from natural gas at high pressure and relatively high CO\textsubscript{2} concentrations. The low CO\textsubscript{2} concentration expected in the reformer exhaust gas means that R&D is required to develop membranes suitable for such an application, including the need to optimize the technology for large-scale CO\textsubscript{2} recovery and to minimize the energy required for separation. As such, this technique is not considered an “available” CO\textsubscript{2} capture and concentration technology for purposes of this BACT analysis.

Adsorption: With this technique, a combustion exhaust gas stream would be fed through a bed of solid material with high surface area, such as a Zeolite or activated carbon. These solid materials can preferentially adsorb CO\textsubscript{2} while allowing other gases (e.g., nitrogen) to pass through. The saturated adsorption bed could be regenerated by either pressure swing (low pressure), temperature swing (high temperature), or electric swing (low voltage) desorption. Application of adsorption to a reformer exhaust gas stream would require either a high degree of compression or multiple separation steps to produce a high CO\textsubscript{2} concentration from the dilute CO\textsubscript{2} concentrations found in combustion unit exhaust gases. This technique has not been used in this type of application and is not suited for this type of application. As such, adsorption is not considered an “available technology” for purposes of this BACT analysis.

Other options: There are additional potential CO\textsubscript{2} capture/concentration measures that are still in laboratory or conceptual stages of development, but are not discussed here because they have not approached commercial demonstration status and therefore, they are clearly not “available” control options for purposes of this BACT analysis.

5.7.2.3.3 CO\textsubscript{2} Capture and Concentration Summary

Currently, the most advanced technique for capturing CO\textsubscript{2} from combustion exhaust gases is treatment of those gases to recover CO\textsubscript{2} by chemical absorption using a regenerable amine solvent. This technique has been demonstrated with combustion exhaust gas compositions that are somewhat similar to the proposed reformer.\textsuperscript{43} The most notable project is a recently operational full-scale demonstration of an amine-based CCS system on a 139 MW coal-fired unit at SaskPower’s Boundary Dam Power Station near Estevan, Saskatchewan, Canada.\textsuperscript{44} Thus, for the purposes of Step 2 in this BACT analysis, it is conservatively assumed that post-combustion capture using chemical absorption can serve as a technically feasible component of a control strategy involving CCS.

\textsuperscript{43} Note that the CO\textsubscript{2} concentration in coal-fired flue gases is dilute at about 12 volume percent, but generally higher than the CO\textsubscript{2} concentrations found in the stack gases exiting the proposed reformer which will be on the order of 5 volume percent.

\textsuperscript{44} IEAGHG. \textit{Integrated Carbon Capture and Storage Project at SaskPower’s Boundary Dam Power Station}, 2015/06, August 2015 (found at http://ieaghg.org/docs/General_Docs/Reports/2015-06.pdf).
5.7.2.3.4 CO₂ Storage in Geologic Formations

There are several options currently being evaluated for permanent storage of CO₂. These options include storage in various geological formations (including saline formations, exhausted oil and gas fields/enhanced oil recovery, and un-mineable coal seams). Each of these options is discussed in more detail below.

In general, the geologic formations that may be appropriate for CO₂ storage consist of layers of porous rock deep underground that are “capped” by a layer or multiple layers of non-porous rock above them. In geologic storage, a well is drilled down into the porous rock and pressurized CO₂ is injected into it. Under high pressure, CO₂ turns to liquid and can move through a formation as a fluid. Once injected, the liquid CO₂ tends to be buoyant and will flow upward until it encounters a barrier of non-porous rock, which can trap the CO₂ and prevent further upward migration.

There are other mechanisms for CO₂ trapping as well. CO₂ molecules can dissolve in brine, react with minerals to form solid carbonates, or adsorb in the pores of porous rock. The degree to which a specific underground formation is amenable to CO₂ storage can be difficult to determine. Ongoing research is aimed at developing the ability to characterize a formation before CO₂ injection in order to predict its CO₂ storage capacity. Another area of research is the development of CO₂ injection techniques that achieve broad dispersion of CO₂ throughout a formation, overcome low diffusion rates, and avoid fracturing the cap rock.

Figure 5-2 illustrates the status of Ohio’s CO₂ storage resources. As shown, virtually all of the potential CO₂ storage capacity in Ohio is in saline formations and oil and gas resources. Figure 5-3 shows the location of these formation in the area of the proposed project.

![Figure 5-2. Estimate of Geologic CO₂ Storage Capacity in Ohio](http://www.natcarbviewer.com) (accessed July 6, 2017).
Some of the major unresolved issues with respect to CO\textsubscript{2} sequestration in geologic formations pertain to the legal framework for closing and remediating geologic storage sites, including liability for accidental releases from these sites. In December 2010, U.S. EPA promulgated a final rule establishing minimum Federal requirements under the Safe Drinking Water Act for underground injection of CO\textsubscript{2} for the purpose of geologic sequestration.\textsuperscript{46} This rule set minimum technical criteria for the permitting, geologic site characterization, area of review and corrective action, financial responsibility, well construction, operation, mechanical integrity testing, monitoring, well plugging, post-injection site care, and site closure of wells for the purposes of protecting underground sources of drinking water. In September 2011, U.S. EPA promulgated a final rule making U.S. EPA the permitting authority for this program nationwide.\textsuperscript{47}

There are several types of geologic formations in which CO\textsubscript{2} can be stored, and each has different opportunities and challenges as briefly described below.

Depleted Oil and Gas Reservoirs: These are formations that held crude oil and natural gas at some time. In general, they are characterized by a layer of porous rock with a layer of non-porous rock which forms a dome. This dome offers the potential to trap CO₂ making this type of formation potentially suited to CO₂ sequestration. As a side benefit of this type of sequestration, CO₂ injected into a depleting oil reservoir may enable recovery of additional oil and gas. When injected into a depleting oil-bearing formation, the CO₂ dissolves in the trapped oil and reduces its viscosity. This process “frees” more of the oil by improving its ability to move through the pores in the rock and flow with a pressure differential toward a recovery well. A CO₂ flood typically enables recovery of an additional 10 to 15 percent of the original oil in place. CO₂ injection is currently being used for the purpose of EOR, but in general, the CO₂ being used is not being recovered from combustion exhaust gases.⁴⁸

The EOR CO₂ pipeline nearest to the proposed Project site is located in Mississippi as illustrated in Figure 5-4 (Jackson Dome). Thus, the use of CO₂ captured and concentrated from the planned reformer for enhanced oil recovery would require construction of a new pipeline that would be on the order of 650 miles in length to connect to the existing CO₂ EOR pipeline network. Alternatively, the CO₂ could be liquefied and shipped via rail or truck to a point where it could be fed into an existing pipeline system.

**Figure 5-4. Current CO₂-EOR operations and infrastructure in the U.S.⁴⁹**

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⁴⁸ One notable exception is SaskPower’s Boundary Dam CCS demonstration project in Canada.
Un-mineable Coal Seams: Un-mineable coal seams are seams that are too deep or too thin to be mined economically. All coals have varying amounts of methane adsorbed onto pore surfaces, and wells can be drilled into un-mineable coal beds to recover this coal bed methane (“CBM”). Initial CBM recovery methods (i.e., dewatering and depressurization) leave a fair amount of CBM in the reservoir. Additional CBM recovery can be achieved by sweeping the coal bed with nitrogen or CO$_2$. Injected CO$_2$ preferentially adsorbs onto the surface of the coal, releasing the methane. Because two or three molecules of CO$_2$ are adsorbed for each molecule of methane released, un-mineable coals seams provide a good storage sink for CO$_2$. Like depleting oil reservoirs, un-mineable coal beds appear to be a good early opportunity for CO$_2$ storage. However, one potential barrier to injecting CO$_2$ into un-mineable coal seams is swelling. When coal adsorbs CO$_2$, it swells in volume. In an underground formation, swelling can cause a sharp drop in permeability, which not only restricts the flow of CO$_2$ into the formation but also impedes the recovery of displaced CBM. Two possible solutions to this challenge include angled drilling techniques and fracturing. Research in this area is ongoing. As shown in Figure 5-2, there are virtually no coal bed CO$_2$ storage resources in Ohio.

Saline Formations: Saline formations are layers of porous rock that are saturated with brine. They are much more commonplace than coal seams or oil and gas bearing rock, and saline formations may have a significant potential for CO$_2$ storage capacity (as illustrated in Figure 5-2). However, much less is known about saline formations than is known about crude oil reservoirs and coal seams, and there is a greater degree of uncertainty associated with their ability to store CO$_2$. Saline formations contain minerals that could react with injected CO$_2$ to form solid carbonates and the carbonate reactions have the potential to be both a positive and a negative. They can increase storage permanence but they also may plug up the formation in the immediate vicinity of an injection well.

Saline formation CO$_2$ storage is an area that has significant ongoing research. One of the most advanced projects in the U.S. is a large-scale research effort aimed at evaluating the technical and commercial feasibility of storing CO$_2$ in the Mt. Simon sandstone saline formation which lies more than a mile below the surface in Illinois. In the ongoing demonstration project, current plans call for injection of approximately five million tons of CO$_2$ into this formation through two injection wells over a period of approximately five years. This R&D work involves comprehensive testing and monitoring elements aimed at furthering the present understanding of CO$_2$ sequestration. As such, it is not appropriate to consider this geologic sequestration option an “available technology” for purposes of this BACT analysis.  

Basalt and Organic Rich Shale Formations: Two additional geological environments being investigated for long-term CO$_2$ storage are basalt formations and organic shale formations. Basalt formations are geological formations of solidified lava. These formations have a unique chemical makeup that could potentially convert injected CO$_2$ into a solid mineral form, thus isolating it from the atmosphere permanently. Some key factors affecting the capacity and

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50 According to U.S. EPA’s top-down BACT guidance, technologies “which have not yet been applied to (or permitted for) full scale operations need not be considered available; an applicant should be able to purchase or construct a process or control device that has already been demonstrated in practice.” This is not the case with saline storage which is currently the subject of on-going R&D in an effort to commercialize this storage option.
injectivity of CO2 into basalt formations are effective porosity and interconnectivity. Current efforts are focused on enhancing and utilizing the mineralization reactions and increasing CO2 flow within basalt formations.

Organic-rich shale formations are another potential geological storage option. Shale is formed from silicate minerals, which are degraded into clay particles that accumulate over millions of years. The plate-like structure of these clay particles causes them to accumulate in a flat manner, resulting in rock layers with extremely low permeability in a vertical direction.

At this time, long-term CO2 storage in basalt formations and organic-rich shale basins has not been demonstrated. Further, there are no such storage resources in the vicinity of the planned project.

5.7.2.3.5 CO2 Storage in the Deep Ocean

It is theorized that the oceans will eventually absorb 80 to 90 percent of the CO2 in the atmosphere and transfer it to the deep ocean.51 Although the ocean has huge potential as a carbon storage sink, the scientific understanding to enable ocean sequestration to be considered as a real option is not yet available. Funding is being provided to researchers in this area to develop the necessary scientific understanding of the feasibility of ocean sequestration. Some of this research work is focused on understanding the mechanisms of CO2 uptake in the ocean and assessing the environmental impacts of CO2 storage. Laboratory studies of the behavior of CO2 droplets and CO2-H2O hydrate structures in simulated ocean environments are being conducted. Due to the lack of commercial demonstration, this sequestration option is not considered an “available technology” for purposes of this BACT analysis.

5.7.2.3.6 CO2 Transportation

“Permanent” carbon storage is possible in a limited number of sites. Sequestration of CO2 from the Project would require either transporting the CO2 to an existing CO2 pipeline for use in enhanced oil recovery or transporting the CO2 to sites in the area for sequestration in a saline formation. Note that this storage option would require development and permitting of a number of injection wells in the Ohio saline formation.

Figure 5-4 shows the current state of CO2-EOR operations and infrastructure in the U.S. As illustrated, the CO2 pipeline network nearest the planned Project is located in Mississippi. Connecting to this pipeline would require the construction of a new pipeline approximately 650 miles long.

Given the distance to the nearest EOR pipeline, an alternative option for transportation of the CO2 is by rail. Assuming that 90% of the CO2 from the proposed reformer is captured and converted to a liquid, its transportation would require about 3 unit trains (i.e., about 300 train

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cars) a week. While this level of transportation is theoretically feasible, it is impractical and thus, construction of a pipeline is the preferred solution for transportation of captured CO₂.

5.7.3 Steps 1 - 4 – CH₄ and N₂O Control Options

5.7.3.1 CH₄ Control Technologies
Available control technologies for the control of CH₄ emissions are the same as for the control of CO and VOC emissions, such as, good combustion practices, oxidation catalysts, and thermal oxidation. Techniques for reducing CH₄ emissions can increase NOx emissions. Consequently, achieving low CH₄ and NOx emission rates is a trade-off in combustion process design and operation. Because CH₄ emissions will be a small fraction of the GHG emissions produced, installing controls for CH₄ alone would not be cost-effective.

5.7.3.2 N₂O Control Technologies
The control of N₂O emissions is primarily achieved through combustion controls. In addition, post combustion catalyst systems including Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR), and thermal destruction control systems may reduce N₂O emissions. However, NOx control systems including conventional SCR systems and SNCR systems, may produce N₂O emissions. Therefore, N₂O emissions may be reduced by not using these systems for the control of NOx emissions. Because N₂O emissions will be a small fraction (< 0.01%) of the GHG emissions produced, installing controls for N₂O emissions alone would not be cost-effective.

5.7.4 Step 2 – Eliminate Technically Infeasible CO₂ Control Options
Technical feasibility of CO₂ control options is discussed below.

5.7.4.1 Use of Low Carbon Fuels
The proposed reformer in the Project will be fired with natural gas, which is the lowest CO₂e emitting fuel available for use in the reformer. This option is considered to be technically feasible and available. It is not currently feasible to utilize a lower emitting fuel in the proposed reformer.

5.7.4.2 Energy Integration Design
Energy efficient process improvements are technically feasible CO₂ control strategies for the proposed Project. Reuse of waste reducing gas is integrated into the Project.

5.7.4.2 Maximised Combustion Efficiency
The use of good combustion design is inherent in the design of proposed reformer. Therefore good combustion design is a feasible GHG emissions control option.

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52 It is estimated that a single unit train would transport approximately 9,500 m³ or approximately 8,000 tons of liquid CO₂.
5.7.4.3 Carbon Capture and Sequestration

As discussed in sub-section 5.7.2.3, permanent CO\textsubscript{2} concentration, capture and sequestration has not been commercially demonstrated as a GHG control technique and significant technical and legal uncertainties remain before this control option can be considered commercially available in the context of a GHG BACT analysis. Further, this option should not be considered a technically feasible GHG control option in the context of determining BACT for the Project because it is unclear that an acceptable long-term storage option can be identified. Nonetheless, in order to ensure that this BACT analysis is conservative, it is assumed that CCS is feasible. The assumption of feasibility incorporates the assumption that the captured CO\textsubscript{2} would be liquefied and transported to the nearby CO\textsubscript{2} storage options for use in enhanced oil recovery. All other CCS sequestration options are considered infeasible for purposes of this BACT analysis based on the development status and/or uncertainties surrounding the use of other carbon sequestration alternatives.

5.7.5 Step 3 – Rank CO\textsubscript{2} Control Options

The baseline GHG control strategy for the Project involves the use of top gas and supplemental natural gas as fuel, energy integration design, and the use of good combustion practices. All of these control techniques are inherent in the design and intended operation of the proposed reformer. Thus, this equipment configuration serves to define the baseline GHG emissions rate for the GHG BACT analysis. Potential GHG emissions from the proposed reformer with these control strategies total approximately 1.55 million tons per year on a CO\textsubscript{2}e basis.\footnote{This value is for reformer exhaust only. There are additional GHG emissions from the DRI reactor and other combustion units proposed as part of the project.}

The top-ranked GHG control strategy, which is conservatively assumed to be technically feasible for purposes of this BACT analysis, involves the application of CCS to the baseline emissions from the reformer exhaust. Assuming 90 percent capture efficiency of CO\textsubscript{2}, this control strategy would reduce GHG emissions from the reformer from \(~1.55\) million tons per year to approximately \(~155,000\) tons per year.\footnote{A capture efficiency of 90\% is typical of the efficiencies that have been used in studies of CO\textsubscript{2} capture systems installed on natural gas combustion sources. See, for example, \textit{Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity Revision 2}, DOE/NETL-2010/1397, November, 2010. Virtually all of the GHG emissions from the reformer are in the form of CO\textsubscript{2}.} For purposes of this BACT analysis, it is assumed that 100 percent of the captured CO\textsubscript{2} would be permanently sequestered although actual sequestration efficiency is likely to be less than 100 percent.

5.7.6 Step 4 – Evaluate Feasible CO\textsubscript{2} Control Options

For the purposes of the following evaluation of the impacts of applying CCS to the reformer CO\textsubscript{2} emissions, chemical absorption using an amine-based solvent is assumed to represent the best CO\textsubscript{2} capture option available. A possible sequestration option for CO\textsubscript{2} is the use of saline formation and/or use of depleted oil and gas reservoirs in the State. Figure 5-5 shows the location of oil and gas fields in Ohio. Majority of oil and gas operations are located in eastern Ohio.

\footnote{This value does not include the additional GHGs that would be emitted due to operating the CCS equipment (\textit{i.e.}, about 300,000 T/yr additional GHG emissions).}
However, for purposes of this analysis, we assumed sequestration in Mt. Simon sandstone formation in western Ohio and eastern Indiana will be available. Sequestration potential for Mt.

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56 Figure 2 from “The Role of CO2 Enhanced Oil Recovery” In Ohio’s Economy and Energy Future Working Paper Prepared for The Pew Center on Global Climate Change. Kleinhenz & Associates 2008.
Simon storage was presented in a report issued by Midwest Regional Carbon Sequestration Partnership as follows.\textsuperscript{57}

\textit{Ohio has the fifth-largest potential sequestration capacity of over 445 gigatonnes, of which, over 35 gigatonnes are in deep saline formations. The saline formations with the largest potential capacity are the Mt. Simon Sandstone (20 gigatonnes) in western Ohio, and the Rose Run (8 gigatonnes) and Medina (5.6 gigatonnes) sandstones in eastern Ohio. These three reservoirs contain 71 percent of the state’s total potential sequestration capacity, and 89 percent of the saline formation capacity.}

Transportation of the compressed CO\textsubscript{2} via pipeline to Mt. Simon formation will require a new ~100-mile pipeline to transport CO\textsubscript{2}. The cost of new pipeline infrastructure is also added to the cost of the project.

We conservatively assumed for purposes of this BACT that CO\textsubscript{2} produced by the project’s reformer could potentially be given or sold for the life of the project for use in depleted oil fields in the area. A number of projects are permitted in Mississippi, Louisiana and Texas and have contracts with Denbury Resources to supply CO\textsubscript{2} to Denbury’s pipeline. These projects do not have GHG BACT limits that require sequestration of the CO\textsubscript{2} being sold to Denbury, and as such are not directly tied to whether Denbury is purchasing their CO\textsubscript{2} or not. If the proposed project has a GHG BACT limit based on CO\textsubscript{2} sequestration, the project would need to include a significant amount of saline sequestration in the event of an interruption in the ability to supply CO\textsubscript{2} to an Ohio CO\textsubscript{2} pipeline for oil and gas field. Note the economics of using CO\textsubscript{2} for EOR is dependent on crude prices, which are difficult to project on a short-term basis, much less on a long-term basis. Given the issues with regard to the use of CO\textsubscript{2} for EOR, the use of saline formation sequestration is believed to be the best option for the project and this evaluation.

To implement CCS, the exhaust stream from the proposed reformer exhaust is assumed to be routed to an amine absorption unit where the CO\textsubscript{2} would be captured and concentrated from around 15 percent to approximately 90 percent. This stream would then be combined with the CO\textsubscript{2} vent stream and would be dehydrated and compressed from ambient pressure to about 2,200 pounds per square inch before injection in saline reservoir or for oil and gas field EOR.

As discussed previously, permanent CO\textsubscript{2} capture from a reformer exhaust gas has not been commercially demonstrated as a GHG control technique and significant technical uncertainties remain. In addition, as shown by the following discussion, the adverse economic, energy, and environmental impacts of CCS as applied to the reformer are significant and beyond those that should be considered acceptable in establishing a BACT limit for GHG emissions from the proposed reformer.

### 5.7.6.1 Economic Impacts Evaluation

The top-performing CO\(_2\) emissions control option is the application of CCS to the proposed reformer. The costs of CCS including concentration, dehydration, compression, and sequestration are substantial as shown in Table 5-12 and as summarized below.

#### Table 5-12. Summary of CCS Impacts Analysis for the Project\(^{58}\)

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Economic Impacts</strong></td>
<td></td>
</tr>
<tr>
<td>CCS Total Installed Cost (including pipeline)</td>
<td>$284,811,892</td>
</tr>
<tr>
<td>Annualized Costs</td>
<td>$106,784,146</td>
</tr>
<tr>
<td>Net CO(_2) Reduced (onsite)</td>
<td>1,171,157 ton/year</td>
</tr>
<tr>
<td>Control Cost-Effectiveness (onsite)</td>
<td>91 $/ton</td>
</tr>
<tr>
<td>Net CO(_2) Reduced (onsite+offsite)</td>
<td>950,127 ton/year</td>
</tr>
<tr>
<td>Control Cost-Effectiveness (onsite+offsite)</td>
<td>112 $/ton</td>
</tr>
<tr>
<td><strong>Environmental Impacts</strong> (CCS Steam &amp; Power Related Emissions)</td>
<td></td>
</tr>
<tr>
<td>NO(_x) Emissions (onsite)</td>
<td>97 ton/year</td>
</tr>
<tr>
<td>NO(_x) Emissions (offsite)</td>
<td>340 ton/year</td>
</tr>
<tr>
<td>SO(_2) Emissions (offsite)</td>
<td>1,367 ton/year</td>
</tr>
<tr>
<td><strong>Energy Impacts</strong></td>
<td></td>
</tr>
<tr>
<td>Increased CCS Power Demand</td>
<td>228,213 MWh/year</td>
</tr>
<tr>
<td>Increased CCS Natural Gas Demand</td>
<td>3,809 MMscf/year</td>
</tr>
</tbody>
</table>

As shown in Table 5-12, the estimated capital cost for the equipment and infrastructure needed for concentration and compression of CO\(_2\) from planned project is in approximately $284 million which is approximately 41% of the cost of the Project itself. The annualized cost of implementing CCS, including operating and maintenance costs and the costs of CO\(_2\) sequestration, is estimated to be in excess of $106 million per year. The resulting control cost-effectiveness of CCS, considering both the onsite and offsite impacts is approximately $112 per ton of CO\(_2\) sequestered. Even if only the site specific costs and CO\(_2\) reductions are considered, cost effectiveness for CCS is $91/ton.

These costs are well above the range of cost effectiveness values considered to be reasonable or acceptable in BACT determinations for control of GHG emissions. For example:

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\(^{58}\) See Appendix D for details of how the values in this table are determined.
• In making the GHG BACT determination for Copano Processing, U.S. EPA determined that control of GHG emissions at a cost-effectiveness of $54/ton is not BACT because it is “economically prohibitive.”

• In making the GHG BACT determination for the City of Palmdale, U.S. EPA determined that control of GHG emissions at a cost-effectiveness of $45/ton is not BACT because it is “economically infeasible.”

• In making the GHG BACT determination for Valero’s McKee Refinery, U.S. EPA determined that control of GHG emissions at a cost-effectiveness of $134/ton is not BACT.

• In making the GHG BACT determination for Freeport LNG Development, L.P.’s Freeport LNG Liquefaction Project, U.S. EPA determined that control of GHG emissions from the amine treatment units was cost prohibitive. The cost effectiveness of this control option was estimated at approximately $14/ton of CO₂ sequestered.

As another benchmark, California Carbon Allowances for September 2017 delivery are currently quoted at less than $13 per ton.

Pursuant to a long-standing policy of U.S. EPA, cost effectiveness as described above, is an appropriate metric for evaluating economic impacts in Step 4 of a top-down BACT analysis. Based on these values and the impact that CCS would have on the required capital investment (i.e., increasing the project capital costs by nearly $284 million which would add ~41% to the cost of the project), the cost of applying CCS to the reformer proposed under the Project of approximately $112 per ton of CO₂ sequestered is unreasonable. In conjunction with the significant adverse energy and environmental impacts of CCS for this application, even if assumed to be technically feasible, this control option does not represent an appropriate basis for establishing a BACT limit for the Project.


60 Responses to Public Comments on the Proposed Prevention of Significant Deterioration Permit for the Palmdale Hybrid Power Project. U.S. EPA Region 9, October 2011. (Cost effectiveness calculated based on listed cost of $78 million/yr for annual emission reduction of 1.7 million tons per year.)


5.7.6.2 Energy Impacts Evaluation

The electric power that would be required to compress captured CO₂ from the Project is approximately 228,000 MWh/year, which is a significant, adverse energy impact associated with the CCS control strategy. This represents enough electricity to power about 21,100 average American homes. In addition, more than 3.5 million cubic feet of natural gas would be consumed annually in generating the steam needed to operate the CO₂ capture and concentration system. This is enough natural gas to heat about 56,000 average U.S. homes during a winter.

5.7.6.3 Environmental Impacts Evaluation

The adverse environmental impacts of implementing CCS for controlling CO₂ emissions from the proposed Project are those associated with the collateral increase in pollutants emitted from steam and electrical generation required to meet the CCS system’s steam and power demands described above. These emissions include more than 80 tons of NOₓ per year. There would also be increases in emissions of other pollutants such as PM10, PM2.5, CO, VOC, SO₂, and HAPs.

5.7.7 Step 5 – Establish GHG BACT

As previously noted, production of steel using HBI generally requires significantly lower energy and generate lower greenhouse gas emissions when compared to conventional steelmaking operations. Further, based on the significant costs and other adverse impacts of the potentially more effective control strategies, IU concludes that the GHG BACT limit for the Project should be based on the following: the use of natural gas, energy integrated design, and the use of good combustion practices through proper operation and maintenance of the units. IU estimated that the CO₂ emissions from the reformer exhaust of 1,553,868 tons per year and CO₂e emissions of 1,554,047 tons per year. IU is proposing the reformer exhaust CO₂e limit of 1.56 million tons per 12-consecutive month on rolling 12-month basis as the BACT limit for GHGs.

5.8 Pressure Relief Vent (Flare) PM/PM10/PM2.5 BACT Analysis

This section presents the required PM/PM10/PM2.5 BACT analysis for the proposed flare. The top gas contains small amount of incombustible solids in the stream as it leaves the reactor top. Solids are removed from the top gas as it leaves the reactor using a top gas venturi scrubber where it is clean and cooled prior to combustion in flare. Virtually all of a reformer’s particulate emissions are PM2.5 and strategies that reduce filterable PM10/PM2.5 will reduce PM (which is filterable only) emissions as well. Thus, these pollutants are appropriately considered together in this BACT analysis.


65 Based on March 2017 EIA estimates that an average home heating with gas consumed 67,700 cubic feet of natural gas during the winter of 2015/16 for Midwest (see: http://www.eia.gov/tools/faqs/faq.cfm?id=867&t=8 Table WF01 - last accessed July 13, 2017).

66 Note that the increase in GHG emissions resulting from steam generation are already accounted for in determining the “net” GHG reductions shown in Table 5-12.
5.8.1  **PM/PM10/PM2.5 BACT Baseline**

There are no state, local or federal regulations applicable to PM/PM10/PM2.5 emissions from the proposed flare. Therefore there is no “BACT baseline” for this operation.

5.8.2  **Step 1 – Identify Available PM/PM10/PM2.5 Control Options**

The identified control options for minimizing emissions from the flare are work practices and equipment design elements that will minimize use of the flare and will minimize emissions from the flare during flaring events:

- Minimizing the combustion process gas by modifying startup and shutdown procedures;
- Designing the flare to meet limitations on maximum exit velocity; and
- Designing the flare to meet minimum net heating values.

Each of these control options is technically feasible and is inherent in the design of the proposed flare. Good combustion practices are also used to reduce PM/PM10/PM2.5 emissions from the fuel burning equipment.

5.8.3  **Step 2 – Eliminate Technically Infeasible PM/PM10/PM2.5 Controls**

Good combustion practices and equipment design elements are feasible options for the proposed flare. No add-on controls are not technically feasible for PM/PM10/PM2.5 emissions from a flare due to intermittent use of this equipment high temperature during operation.

5.8.4  **Step 3 – 5 Flare BACT for PM/PM10/PM2.5**

Equipment design or work practice requirements are acceptable under the definition of BACT when technological or economic limitations on the application of measurement methodology would make the imposition of an emissions standard infeasible. That criterion is met with respect to particulate matter emissions from the flare due to the intermittent nature of this operation. For the proposed flare, the PM/PM10/PM2.5 BACT represents good combustion practices and equipment design elements for both natural gas pilot and the pressure relief events.

5.9  **Pressure Relief Vent NOx, CO, GHG BACT Analyses**

This section presents the required NOx, CO, and GHG BACT analysis for the proposed flare. Top gas combustion in the flare and natural gas combustion in the pilot results in formation of products of combustion. However, other than flare pilot, the emissions occur on intermittent basis during process upsets, startup, and shutdown.

5.9.1  **NOx, CO, GHG BACT Baselines**

There are no state, local or federal regulations applicable to NOx, CO, GHG emissions from the proposed flare. Therefore there is no “BACT baseline” for this operation.

5.9.2  **Step 1 – Identify Available NOx, CO, GHG Control Options**

The identified control options for minimizing emissions from the flare are work practices and equipment design elements that will minimize use of the flare and will minimize emissions from
the flare during flaring events:

- Minimizing the combustion process gas to be flared by modifying startup and shutdown procedures;
- Designing the flare to meet limitations on maximum exit velocity; and
- Designing the flare to meet minimum net heating values.

Each of these control options is technically feasible and is inherent in the design of the proposed flare. Other controls used for gas combustion devices include:

- Good combustion practices;
- Oxidation catalyst for CO control; and
- LNBs and SCR for NOx control.

These controls are already described in the reformer exhaust BACT analysis presented earlier in this section.

5.9.3 Step 2 – Eliminate Technically Infeasible NOx, CO, GHG Controls

Good combustion practices GCP is considered technically feasible and is the only control identified as BACT for flares. Add-on controls such as oxidation catalyst and SCR are not technically feasible due to the high combustion temperatures and the very intermittent use of the flare for combusting process gas.

5.9.4 Step 3 – 5 Flare BACT for NOx, CO, GHG

The most effective control strategy for NOx, CO, and GHG emissions from the flare are the work practices and equipment design elements identified above. Establishment of equipment design and work practice requirements as BACT is appropriate in this instance because it is infeasible to apply a measurement methodology for demonstration of compliance with numeric limits on emissions rates. The configuration of the elevated flare renders both manual stack testing and continuous emissions monitoring systems technically infeasible. IU proposes the following equipment design and work practices.

- The HBI process will minimize flaring resulting from startups, shutdowns, and upset events by operating at all times in accordance with an approved flare minimization plan. The plan shall include the following elements:
  - Procedures for operating and maintaining the flare during periods of startup, shutdown, and process upset.
  - A program of corrective action for malfunctioning equipment in the HBI process.
  - Procedures to minimize discharges to the flare gas system during the planned and unplanned startup or shutdown of HBI process plant equipment.
- The flare shall be designed to meet limitations on maximum exit velocity, as set forth in the NSPS general provisions at 40 CFR § 60.18. The flare shall be designed to meet minimum net heating value requirements for fuel gas combusted in the flares, as set forth at 40 CFR § 60.18.
5.10 Seal Gas Vents from Charge Hopper, Bottom Seal Gas, Hot Briquette Exhaust PM/PM10/PM2.5 BACT Analysis

This section presents the required PM/PM10/PM2.5 BACT analysis for the seal gas vents/exhausts from charge hopper, bottom seal gas, and hot briquette operation. The seal gas contains small amount of fine particulate matter in the stream from oxide passing through the furnace. In addition, the top seal gas, which is released through the charge hopper exhaust, has small amount of particulate as products of combustion. Each of these emissions points will be equipped with venturi scrubbers to control particulate matter emissions from the release of seal gas.

5.10.1 PM/PM10/PM2.5 BACT Baseline

There are no state, local or federal regulations applicable to PM/PM10/PM2.5 emissions from the seal gas exhausts. Therefore, there is no “BACT baseline” for this operation.

5.10.2 Step 1 – Identify Available PM/PM10/PM2.5 Control Options

The seal gas that is exhausted from the furnace contains small amount fines generated during the action of ore pellets passing through the furnace. The identified potential control options for controlling emissions from the seal gas exhausts are identified below:

(a) Fabric filter (baghouse)
(b) Electrostatic precipitator (ESP)
(c) Venturi scrubber
(d) Cyclone

In addition to the add-on controls, good combustion practices (GCP) can also be used for reducing particulate loading to the top seal gas that is the cooled flue gas from the reformer exhaust.

5.10.3 Step 2 – Eliminate Technically Infeasible PM/PM10/PM2.5 Controls

Particulates in the DRI process gas are formed in a reduced oxygen atmosphere, and these particles are known to react to oxygen when exposed to the atmosphere. This exothermal reaction is known to cause fires. Therefore, the nature of the DRI particulates makes the application of a baghouse to be a significant safety hazard and the use of a baghouse for cleaning the seal gas is considered technically infeasible.

DRI particulates have high iron content. ESPs are especially sensitive to electrical resistivity, and iron particles adhere very strongly to the ESP collection plates. This makes it difficult to remove the iron particles, which quickly reduces ESP efficiency. Additionally, the application of an ESP creates a significant fire safety hazard when handling the captured DRI particles if exposed to air. The use of an ESP for cleaning the seal gas is considered technically infeasible.

As is the case for the use of a baghouse or ESP, the use of a cyclone for removal of DRI particles creates a significant fire safety hazard when handling the captured DRI particles. The use of a cyclone for cleaning the vent gas is considered technically infeasible.
The use of a venturi scrubber is considered technically feasible because the DRI particulates are collected wet, and do not create a fire safety hazard.

Use of venturi scrubber for controlling particulate matter in seal gas is the only available control strategies identified and are considered to be a technically feasible for establishing the PM/PM10/PM2.5 BACT limits for the three seal gas exhausts.

**5.10.4 Step 3 – Rank PM/PM10/PM2.5 Control Options**

The PM/PM10/PM2.5 control strategies selected for the proposed seal gas exhausts that are considered technically feasible are:
- Venturi scrubber.
- Good combustion practices at the reformer for upper seal gas release.

IU proposes to use the above control strategies to control the emissions of PM/PM10/PM2.5 from the three seal gas exhausts.

**5.10.5 Step 4 – Evaluate Feasible PM/PM10/PM2.5 Control Options**

The selected PM/PM10/PM2.5 control strategy will not have any material adverse energy, environmental or economic impacts, and therefore it is appropriate that this strategy serve as the basis for establishing the PM/PM10/PM2.5 BACT limits for the charge hopper exhaust, bottom seal gas exhaust, and hot briquette exhaust.

**5.10.6 Step 5 – Establish PM/PM10/PM2.5 BACT**

The use of venturi scrubber and use of good combustion practices at the reformer are the most effective control basis for establishing the PM/PM10/PM2.5 BACT limits for the three seal gas exhausts. The following table presents the proposed PM/PM10/PM2.5 limits for the three seal gas exhausts equipped with venturi scrubbers.

<table>
<thead>
<tr>
<th>Emission Point</th>
<th>Emission Limit (lb/hour)*</th>
<th>Basis (gr/dscf)**</th>
</tr>
</thead>
<tbody>
<tr>
<td>TR-28 Charge hopper exhaust</td>
<td>PM/PM10/PM2.5 -0.1</td>
<td>PM - 0.007</td>
</tr>
<tr>
<td>P-1 Bottom seal gas exhaust</td>
<td>PM - 2.56</td>
<td>PM(f) - 0.007</td>
</tr>
<tr>
<td></td>
<td>PM10/PM2.5 – 2.61</td>
<td>PM(c) – 0.00015</td>
</tr>
<tr>
<td>P-3 Hot briquette exhaust</td>
<td>PM - 3.97</td>
<td>PM(f) – 0.007</td>
</tr>
<tr>
<td></td>
<td>PM10/PM2.5 – 4.10</td>
<td>PM(c) – 0.00024</td>
</tr>
</tbody>
</table>

*Derivations of the emissions limitations above are provided in Appendix C detailed emissions calculations. **The basis for establishing the emissions limitations were provided by the supplier for the proposed scrubbers that will control the three seal gas exhausts.

Compliance with these limits will be demonstrated using 40 CFR Part 60, Appendix A, Methods 1 through 4 and Method 5 and 202.
5.11 Seal Gas Vents from Charge Hopper, Bottom Seal Gas, Hot Briquette Exhaust NOx and CO Analyses

This section presents the required NOx and CO BACT analyses for the seal gas exhausts from charge hopper, bottom seal gas, and hot briquette exhaust. The portion of seal gas and small amount of reducing gas generated in the furnace, which is released through these exhausts, contain small amount of NOx and CO. As part of the equipment design, IU is proposing to use nitrogen gas as seal gas for bottom seal gas in the shaft furnace. This will minimize CO emissions from the bottom seal gas.\(^{67}\)

5.11.1 NOx and CO BACT Baseline

There are no state, local or federal regulations applicable to NOx and CO emissions from the seal gas exhausts. Therefore, there is no “BACT baseline” for this operation.

5.11.2 Step 1 – Identify Available NOx and CO Control Options

A review of recent permit actions and search of U.S. EPA’s RBLC database did not reveal any application of NOx or CO add-on controls for the shaft furnace seal gas exhausts. Use of NOx and CO controls for the reformer exhaust flue gases that are used as seal gas is previously discussed in sections 5.5 and 5.6 as part of the BACT analyses. Use of optimum equipment design is the only NOx and CO minimization strategy available for the three seal gas exhausts.

5.11.3 Step 2 – Eliminate Technically Infeasible NOx and CO Control Options

Add-on controls such as SCR, SNCR, oxidation catalysts and others are not technically feasible for use with the seal gas exhausts. Optimum equipment design is the only feasible option for control of NOx and CO emissions from the seal gas exhausts.

5.11.4 Step 3 – 5 Seal Gas Exhausts BACT for NOx and CO

The most effective control strategy for NOx and CO emissions from the seal gas exhausts is the use of optimum equipment design for the shaft furnace. No additional controls are feasible for the small portion of seal gas releases. Equipment design or work practice requirements are acceptable under the definition of BACT when technological or economic limitations on the application of measurement methodology would make the imposition of an emissions standard infeasible. That criterion is met with respect to NOx and CO emissions from the seal gas exhausts due to the intermittent nature of this operation. Since there are no add-on controls considered BACT for the seal gas exhausts, IU proposes optimum equipment design as NOx and CO BACT for the shaft furnace seal gas exhausts.

\(^{67}\) Use of the reformer exhaust flue gases in the bottom seal gas system will bring the CO\(_2\) rich gases in contact with the hot DRI. The hot DRI, in the bottom of the shaft furnace, will strip some of the oxygen from CO\(_2\) in the flue gases used as seal gas forming CO and Fe\(_2\)O\(_3\). This results in the generation of CO emissions from the bottom seal gas exhaust when reformer exhaust gases are used as seal gas. IU is not planning to use the reformer exhaust flue gases and instead use the nitrogen gas as seal gas in the bottom seal gas system of the shaft furnace. (explanation provided by the MIDREX representative)
5.12 Seal Gas Vents from Charge Hopper, Bottom Seal Gas, Hot Briquette Exhaust GHG Analysis

The DRI reactor or shaft furnace uses the reducing gas generated by the reformer to react with iron ore to form metallized reduced iron. The DRI reactor, which does not involve combustion, reacts CO and H₂ to scavenge oxygen from the ore pellets, reducing the oxygenation state of the ore. This results in pure iron, CO₂, and water from the following reactions.

\[
\begin{align*}
\text{Fe}_2\text{O}_3 + 3 \text{ CO} & \rightarrow 2 \text{ Fe} + 3 \text{ CO}_2 \\
\text{Fe}_2\text{O}_3 + 3 \text{ H}_2 & \rightarrow 2 \text{ Fe} + 3 \text{ H}_2\text{O}
\end{align*}
\]

Reducing gases from the reformer (rich in CO (5%) and H₂ (95%)) enter at the bottom of the DRI reactor and ore pellets are fed from the top. As the reduction reaction occurs, CO₂ and water vapor are formed in the gas stream as reaction byproducts. The spent reducing gases then exit from the top of the furnace for recycle to the reformer after undergoing cleaning and cooling in the system. A portion of clean top gas, enriched with natural gas, is routed as fuel to the reformer burners. The remaining clean top gas is compressed mixed with natural gas to form feedstock for the reformer (after preheating). The reformer produces reforming gases for re-use in the DRI reactor. The portion of seal gas and small amount of reducing gas generated in the furnace, which is released through charge hopper, bottom seal gas, and hot briquette exhaust exhausts, contain small amount of GHG.

This section presents the required GHG BACT analysis for the seal gas exhausts from the shaft furnace. As previously noted, as part of the equipment design, IU is proposing to use nitrogen gas as seal gas for the bottom seal gas in the shaft furnace. This will also minimize GHG emissions from the bottom seal gas.

5.12.1 GHG BACT Baseline

There are no state, local or federal regulations applicable to GHG emissions from the seal gas exhausts. Therefore, there is no “BACT baseline” for this operation.

5.12.2 Step 1 – Identify Available GHG Control Options

A review of recent permit actions and search of U.S. EPA’s RBLC database did not reveal any application of add-on controls for the shaft furnace seal gas exhausts. Use of GHG controls for the reformer exhaust flue gas that is used as seal gas is previously discussed in section 5.7 as part of the BACT analysis. Operational strategies for mitigation of GHG emissions is described below.

1. Optimum equipment operational practices, which includes proper equipment maintenance, is the key option available to minimize GHG emissions from the three seal gas exhausts. Careful monitoring and control of the pressure and flow in the seal gas legs to assure that the process gas is retained in the furnace and that the furnace is operated to minimize over pressurization (and thus furnace process gas venting thru the flare) is the optimum way to mitigate the amount of seal gas that will be vented to atmosphere.
2. Use of energy integration. Since the top seal gas is dewatered and dehydrated reformer
flue gas, the way to mitigate GHG emissions from the reformer is to assure that the reformer is operated using energy integration for heat recovery and good combustion practices as discussed in the BACT discussion on the reformer, above.

5.12.3 Step 2 – Eliminate Technically Infeasible GHG Control Options
Optimum equipment operational practices and energy integration are the only feasible option for control of GHG emissions from the seal gas exhausts.

5.12.4 Step 3 – 5 Seal Gas Exhausts BACT for GHG
The most effective control strategy for GHG emissions from the seal gas exhausts is the use of optimum equipment operational practices and energy integration for the shaft furnace. No additional controls are feasible for the small portion of seal gas releases. Equipment design or work practice requirements are acceptable under the definition of BACT when technological or economic limitations on the application of measurement methodology would make the imposition of an emissions standard infeasible. That criterion is met with respect to GHG emissions from the seal gas exhausts due to the intermittent nature of this operation. Since there are no add-on controls considered BACT for the seal gas exhausts, IU proposes optimum equipment operational practices and energy integration as GHG BACT for the exhausts from charge hopper, bottom seal gas, and hot briquette.

5.13 Briquette Cooling System Vapor Removal Vent
PM/PM10/PM2.5 BACT Analysis

This section presents the required PM/PM10/PM2.5 BACT analysis for the exhaust from the briquette cooling system vapor removal vent. The HBI cooling system sprays water to cool the HBI product. Steam and vapor from the process are cooled and exhausted to the atmosphere by a hood. This emissions point will be equipped with venturi scrubber to control particulate matter emissions from release of seal gas.

5.13.1 PM/PM10/PM2.5 BACT Baseline
There are no state, local or federal regulations applicable to PM/PM10/PM2.5 emissions from the briquette cooling system vapor removal vent. Therefore, there is no “BACT baseline” for this operation.

5.13.2 Step 1 – Identify Available PM/PM10/PM2.5 Control Options
The steam/vapor that are exhausted from the briquette cooling system vapor removal vent contains small amount particulate matter as result of dissolved solids in the cooling water. The identified potential control options for controlling emissions from this exhaust are identified below:

(a) Mist eliminator
(b) Venturi scrubber
(c) Other add-on particulate matter controls such as ESP, baghouse, cyclone etc.
5.13.3 Step 2 – Eliminate Technically Infeasible PM/PM10/PM2.5 Controls

As previously discussed, the exhaust stream is laden with high moisture content and water vapor. Therefore, particulate matter controls such as ESP, baghouse, cyclone etc. are not technically feasible for this operation.

Use of mist eliminator and venturi scrubber for controlling particulate matter in the briquette cooling system vapor removal vent are the only available control strategies identified and are considered to be a technically feasible for establishing the PM/PM10/PM2.5 BACT limits.

5.13.4 Step 3 – Rank PM/PM10/PM2.5 Control Options

The PM/PM10/PM2.5 control strategies selected for the proposed vent that are considered technically feasible are use of a mist eliminator and venturi scrubber. IU proposes to use these control strategies to control the emissions of PM/PM10/PM2.5 from the vent for this process.

5.13.5 Step 4 – Evaluate Feasible PM/PM10/PM2.5 Control Options

The selected PM/PM10/PM2.5 control strategy will not have any material adverse energy, environmental or economic impacts, and therefore it is appropriate that this strategy serve as the basis for establishing the PM/PM10/PM2.5 BACT limits for the briquette cooling system vapor removal vent.

5.13.6 Step 5 – Establish PM/PM10/PM2.5 BACT

The use of venturi scrubber and mist eliminator at the briquette cooling system vapor removal vent are the most effective control basis for establishing the PM/PM10/PM2.5 BACT limits. IU’s proposal for PM/PM10/PM2.5 limits for the briquette cooling system vapor removal vent exhaust is 3.80 lb/hour based on the outlet grain loading of 0.008 gr/dscf. Compliance with this limits will be demonstrated by properly operating the equipment within the supplier’s specifications and optimum operating practices.

5.14 Degasser Exhaust BACT Analyses

This section presents the required CO and CO2 BACT analyses for the process water degasser exhaust. Due to the direct contact of process water with process gases (especially top gas), some gas constituents (especially CO and CO2) are dissolved in water at an elevated process gas pressure. The dissolved CO and CO2 is stripped in the degasser using pressurized air prior to the clarifier. However, the flow and concentration of CO and CO2 are irregular since entry to and from the pressurized DRI process is intermittent.

5.14.1 Degasser Exhaust CO BACT Analysis

CO is stripped from the cooling water prior to entering the clarifier. The degasser exhaust will be intermittent in nature and will contain a relatively low CO concentration. CO BACT analysis for the degasser exhaust is addressed in this section.
5.14.1.1 CO BACT Baseline
There are no state, local or federal regulations applicable to CO emissions from the degasser exhaust. Therefore, there is no “BACT baseline” for this operation.

5.14.1.2 Step 1 – Identify Available CO Control Options
A review of recent permit actions and search of U.S. EPA’s RBLC database did not reveal any application of CO add-on controls for degassers at DRI plants. The following list of controls have been used to control CO emissions from other process water stripper streams.
- Optimum equipment design and operating practices
- Flare

5.14.1.3 Step 2 – Eliminate Technically Infeasible NOx and CO Control Options
Combustion of stripped CO in flare or similar combustion devices is potentially applicable for this operation. However, the concentration of CO is only 0.03% of the exhaust stream. On the other hand water/moisture content of the exhaust stream is approximately 26%. In addition, the CO concentration in the exhaust stream fluctuates based on air and water flows in the degasser. Use of flare on this type of operation is not technically feasible.

5.14.1.4 Step 3 – 5 Degasser Exhaust BACT for CO
The most effective control strategy for CO emissions from the degasser exhaust is the use of optimum equipment design and operation. No additional controls are feasible for the CO emissions from stripping of process water stream. Equipment design or work practice requirements are acceptable under the definition of BACT when technological or economic limitations on the application of measurement methodology would make the imposition of an emissions standard infeasible. That criterion is met with respect to CO emissions from the degasser exhaust due to the intermittent nature of this operation. Since there are no add-on controls considered BACT for the degasser exhaust, IU proposes optimum equipment design and operation as BACT for CO from the degasser exhaust.

5.14.2 Degasser Exhaust GHG BACT Analysis
Along with CO, some of the CO₂ is also stripped from the cooling water prior to entering the clarifier. CO₂ BACT analysis for the degasser exhaust is addressed in this section.

5.14.2.1 GHG BACT Baseline
There are no state, local or federal regulations applicable to GHG emissions from the degasser exhaust. Therefore, there is no “BACT baseline” for this operation.

5.14.2.2 Step 1 – Identify Available GHG Control Options
A review of recent permit actions and search of U.S. EPA’s RBLC database did not reveal any application of CO₂ add-on controls for degassers at DRI plants. The following list of controls have been used for process water stripper streams.
- Caustic/water wash scrubber – A caustic/water scrubber can be used to remove CO₂ from the process water degasser exhaust. In addition, production of caustic soda (NaOH) will result in generation of off-site GHG emissions both from energy use as well as from
chemical reaction.

- Optimum equipment design and operating practices – These include appropriate equipment design and maintenance within the operational parameters for minimizing emissions.

5.14.2.3 **Step 2 – Eliminate Technically Infeasible GHG Control Options**

Use of caustic/water wash scrubber for small amount of CO₂ in the process water degassing operation may be technically feasible. However, such an application does not exist. In addition, due to intermittent nature of the process water stripping load, it is likely to not operate properly.

5.14.2.4 **Step 3 – Rank Remaining GHG Control Strategies**

Application of caustic/water scrubber can remove almost 99% of CO₂ depending upon the type of reagent used.

5.14.2.5 **Step 4 – Evaluate Remaining GHG Control Strategies**

Although technically feasible, use of a caustic/water scrubber to control the small amount of CO₂ emissions that occur from process water degassing is likely to be cost prohibitive. Caustic soda prices ranged from $400 to $600 per ton. Since CO₂ removal requires caustic soda use at the rate of at least 1:1 molar ratio, the cost effectiveness of this option will be at least $400 per ton of CO₂ removed. Process water degassing operation emits very small amount (approximately 1,100 tons per year or 0.08% of site-wide CO₂ emissions). Due to the unreliability of operation, small potential CO₂ reductions, and high cost of reagent used, this technology is deemed cost prohibitive.

5.14.2.6 **Step 5 – Establish GHG BACT**

The most effective control strategy for CO₂ emissions from the degasser exhaust is the use of optimum equipment design and operation. No additional controls are feasible for the CO₂ emissions from stripping of process water stream. Equipment design or work practice requirements are acceptable under the definition of BACT when technological or economic limitations on the application of measurement methodology would make the imposition of an emissions standard infeasible. That criterion is met with respect to CO₂ emissions from the degasser exhaust due to the intermittent nature of this operation. Since there are no add-on controls considered BACT for the degasser exhaust, IU proposes optimum equipment design and operation as BACT for CO₂ from the degasser exhaust.

5.15 **Cooling Tower PM/PM10/PM2.5 BACT Analysis**

The project includes a mechanical draft direct contact cooling tower. This section presents the required PM/PM10/PM2.5 BACT analysis for the proposed cooling tower. In a mechanical draft cooling tower, cooling is provided by evaporation of recirculating water into a stream of flowing air. A small amount of this water is entrained in the air stream in the form of liquid droplets or mist. Demisters (i.e., drift eliminators) are used at the air discharge point of cooling towers to

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reduce the quantity of water droplets entrained in the air. The water droplets that pass through the demisters and are emitted to the atmosphere are known as drift. As these droplets drift from the cooling processes, they tend to evaporate and the solids in the droplet become particulate matter emissions. Therefore, the proposed cooling tower emit PM, PM10, and PM2.5.

The size distribution of the particulates emitted from a particular cooling process is a function of two main factors – the size distribution of the wet droplets emitted and the solids content of the droplets. A well-established model of droplet drying is that a droplet dries to form a single particle. Thus, for any given wet particle size, larger wet droplet diameters and higher droplet the solids contents form larger dry particles. The converse is true in that smaller wet droplets and lower solids contents produce finer particles.

The maximum target total dissolved solids (TDS) level in the Project cooling water is 1,100 ppmw. This level provides an appropriate balance between water usage, equipment reliability, and particulate emissions.

5.15.1 PM/PM10/PM2.5 BACT Baseline

There are no state, local or federal regulations applicable to the PM/PM10/PM2.5 emissions from the proposed cooling process. Therefore there is no “BACT baseline” for this unit-pollutant group.

5.15.2 Step 1 – Identify Available Control Options

Two control strategies were identified for limiting particulate matter emissions from the proposed cooling tower:

- Use of high-efficiency drift eliminators; and
- Reducing the TDS content of cooling water.

Each of these techniques is discussed further below.

5.15.2.1 High-Efficiency Drift Eliminators

High-efficiency drift eliminators (also known as mist eliminators or demisters) reduce cooling water drift by collecting entrained droplets at the point of air discharge from the cooling tower. These drift eliminators function by forcing the airstream leaving a cooling unit to make changes in direction. When the air is forced to change direction, the inertia of any entrained drift droplets keeps them moving in a straight line, causing them to impact the wall of the drift eliminator where they coalesce and then drain back into the wet section of the cooling unit. A simplified illustration of this process is shown in Figure 5-6 below.

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High-efficiency drift eliminators reduce emissions of particulate matter of all sizes, regardless of TDS level. They are most effective at reducing emissions of larger droplets because the larger droplets are more susceptible to collection via inertial impaction. The most effective, commercially available drift eliminators for cooling process in the size ranges required for the Project have a vendor-specified maximum total liquid drift of 0.0005 percent of the circulating water flow rate. This value is consistent with the lowest cooling tower BACT limits identified in the RBLC. See Table 5-14 below.

### Table 5-14. Summary of PM/PM10/PM2.5 BACT Precedence for Cooling Tower

<table>
<thead>
<tr>
<th>RBL C ID/ State</th>
<th>Facility Name</th>
<th>Permit Date</th>
<th>Process Description</th>
<th>Control</th>
<th>Drift Loss Basis</th>
</tr>
</thead>
<tbody>
<tr>
<td>IN-0263</td>
<td>Midwest Fertilizer</td>
<td>3/23/2017</td>
<td>Cooling Tower</td>
<td>High Efficiency Drift Eliminator</td>
<td>0.0005%</td>
</tr>
<tr>
<td>TX-0815</td>
<td>Total Petrochemicals &amp; Refining USA Inc.</td>
<td>01/17/2017</td>
<td>Cooling Tower</td>
<td>Drift Eliminator</td>
<td>Control Efficiency of 99.999%</td>
</tr>
<tr>
<td>LA-0317</td>
<td>Methanex USA LLC</td>
<td>12/22/2016</td>
<td>Cooling Tower</td>
<td>Drift Eliminator</td>
<td>0.0010%</td>
</tr>
<tr>
<td>LA-0306</td>
<td>Topchem Pollock LLC</td>
<td>12/20/2016</td>
<td>Cooling Tower</td>
<td>High Efficiency Drift Eliminator</td>
<td>0.001%</td>
</tr>
<tr>
<td>MI-0424</td>
<td>Holland Board of Public Works</td>
<td>12/05/2016</td>
<td>Cooling Tower</td>
<td>Mist/Drift Eliminator</td>
<td>0.0005%</td>
</tr>
<tr>
<td>IN-0255</td>
<td>Nucor Steel</td>
<td>9/21/2016</td>
<td>Cooling Tower</td>
<td>Drift Eliminator</td>
<td>0.0010%</td>
</tr>
<tr>
<td>TX-0725</td>
<td>Voestalpine Texas LLC</td>
<td></td>
<td>Cooling Tower</td>
<td>Drift Eliminator</td>
<td>0.0005%</td>
</tr>
</tbody>
</table>

#### 5.15.2.2 Circulating Water TDS Reduction

The reduction in cooling tower particulate matter emissions achievable through reductions in TDS content is complex. Any reduction in TDS content will achieve a proportionate decrease in total PM emissions (*i.e.*, all emissions of finely divided solid or liquid material, other than uncombined water, with an aerodynamic diameter less than 100 μm). However, the particle size of a dried drift droplet is dependent upon TDS since higher TDS levels result in larger dried particle sizes and lower TDS levels result in smaller dried particle sizes. As a result, under certain circumstances, a reduction in TDS can actually cause an increase in PM10 and/or PM2.5 emissions.
5.15.3 **Step 2 – Eliminate Technically Infeasible Options**

Both of the identified control options are technically feasible and are therefore considered further in this BACT analysis.

5.15.4 **Step 3 – Rank Control Options**

The most effective control strategy for controlling PM, PM10, and PM2.5 emissions from the cooling tower is the use of a high efficiency drift eliminator. Using such a drift eliminator in combination with reduced TDS levels is also effective in reducing PM emissions, but less so in reducing PM10 and PM2.5 emissions. Expected TDS in the cooling water at 1,100 ppmw is on the lower side low for cooling applications.

5.15.5 **Step 4 – Evaluate Feasible Control Options**

For new construction, the use of a high-efficiency drift eliminator that is capable of achieving a drift loss rate of 0.0005% has no material adverse energy, environmental, or economic impacts while providing material reductions in PM, PM10, and PM2.5 emissions.

5.15.6 **Step 5 – Establish BACT**

Equipment design or work practice requirements are acceptable under the definition of BACT when technological or economic limitations on the application of measurement methodology would make the imposition of an emissions standard infeasible. That criterion is met with respect to particulate matter emissions from the cooling tower due to their physical configuration. Therefore, IU proposes that a design standard – installation of drift eliminators with a maximum drift rate specification of 0.0005 percent or less – be established as BACT for PM/PM10/PM2.5 emissions from the cooling tower. This design standard is consistent with the most stringent recently established PM/PM10/PM2.5 BACT identified.

5.16 Emergency Engines BACT Analyses

The Project will include one emergency fire water booster pump booster engine and one emergency engine generator. These emergency equipment will be powered by compression-ignition reciprocating internal combustion engines (i.e., a diesel fueled RICE) with a rated output of 250 brake horsepower (“bhp”) for the fire water booster pump and 2,700 bhp for the emergency generator. These engines are generally similar to engines that are regulated as non-road mobile engines under 40 CFR parts 89 and 1039. These engines are subject to BACT review for PM/PM10/PM2.5, NOx, CO, and GHG emissions.

5.16.1 **Emergency Engines PM/PM10/PM2.5 BACT Analysis**

5.16.1.1 **PM/PM10/PM2.5 BACT Baseline**

As discussed in Section 4 herein, the emergency engines will be affected facilities subject to the standards for RICE under subpart IIII of 40 CFR part 60. The minimum standards that would meet BACT requirements for particulate matter emissions from these engine are as follows:
• The fire water pump booster engine, pursuant to 40 CFR § 60.4205(c), will be required to meet the PM emission standard established for nonroad engines of the same model year pursuant to Table 4 of subpart III. The PM emission standard is a specification of 0.15 g/bhp-hr, as determined by the engine manufacturer using the nonroad engine testing procedures set forth at 40 CFR §§ 89.401 to 89.424 and at Table 4 of subpart III.

• The emergency generator engine, pursuant to 40 CFR § 60.4205(b), will be required to meet the PM emission standard established for nonroad engines of the same model year 40 CFR § 60.4202. Per 40 CFR §60.4202(b)(2), specific limitations in 40 CFR §§ 89.112 and 89.113 are applicable to the emergency engine that is not a fire pump. The PM emission standard is a specification of 0.20 g/kW-hr, as determined by the engine manufacturer using the nonroad engine testing procedures set forth at 40 CFR §§ 89.401 to 89.424.

5.16.1.2 Steps 1 – Identify Available Control Options

Identified control technologies and techniques for PM/PM10/PM2.5 emissions from compression-ignition RICE include the following:

• Engine manufacturer certification for NSPS, injection timing retard, also called ignition timing retard, which involves delaying the fuel injection point in each engine cycle such that the heat release from fuel combustion occurs during the cylinder expansion. Lower NOX emissions are achieved by reducing the peak combustion temperature;

• An oxidation catalyst for control of organics, similar to the catalyst described in earlier sections; and

• Catalyzed diesel particulate filters, which control emissions by capturing particulate matter in a filter media, typically a ceramic wall flow substrate, and then by oxidizing it in the oxygen-rich atmosphere of diesel exhaust. The particulate matter emitted by diesel engines includes semi-volatile organic compounds that are regulated as VOC.

5.16.1.3 Step 2 – Eliminate Technically Infeasible Options

All of the identified control options are assumed to be technically feasible.

5.16.1.4 Step 3 – Rank Feasible Control Options

The third-ranked control option for particulate matter emissions comprise the use of internal combustion engines certified by the engine manufacturer to meet the applicable NSPS emission standards for non-road, compression-ignition engines. Engines meeting these standards may use multiple in-engine control technologies including injection timing retard and exhaust gas recirculation. These technologies will reduce VOC emissions from the engines resulting in lower reported PM emissions.

The second-ranked control option for PM/PM10/PM2.5 emissions involves the use of oxidation catalyst in conjunction with the third-ranked control option. For the purposes of this BACT analysis, it is assumed that an 80 percent reduction in VOC emissions is achievable with this control option. This likely overstates the achievable emission reduction by a significant amount, as the engine will have very little time operating under the steady-state conditions favorable for oxidation catalyst system performance.
The highest-ranked control option for PM/PM10/PM2.5 emissions involves the use of catalyzed diesel particulate filters in conjunction with the third-ranked control option. For the purposes of this BACT analysis, it is assumed that 90 percent emission reduction is achievable.

### 5.16.1.5 Step 4 – Evaluate Feasible Control Options

Third-ranked control option, use of certified engines, will not cause any adverse energy, environmental, or economic impacts. The higher-ranked control options will cause adverse impacts that warrant their exclusion as the basis for establishing PM/PM10/PM2.5 BACT limits from the fire pump booster engine and the emergency generator engine. The adverse impacts include energy impacts, due to reduced energy efficiency attributable to increased pressure drop, and environmental impacts associated with catalyst disposal. These adverse energy and environmental impacts are minimal.

The adverse economic impacts that would result from requiring catalytic add-on controls for an emergency use, internal combustion engine would be significant. Economic analyses prepared by U.S. EPA in its rulemaking for NSPS 40 CFR 60 Subpart III showed that, for emergency use engines, the cost of oxidation catalyst control and catalyzed diesel particulate filters are not cost effective.\(^{70}\) The 2005 rulemaking memorandum in the docket indicates oxidation catalyst cost effectiveness of over $100,000 per year of PM controlled and the cost of catalyzed diesel particulate filters and NO\(_X\) adsorbers are more than $20,000 per ton of total NO\(_X\) and VOC emission reduction.\(^{71}\) Considering the minimal environmental benefit that would result, and the adverse energy, economic and environmental impacts described above, these controls are rejected as BACT.

### 5.16.1.6 Step 5 – Establish BACT

The fire pump booster engine and the emergency generator engine to be installed at the HBI Facility will be certified by the equipment manufacturer to meet the applicable emission standards for nonroad, compression-ignition engines, as codified in 40 CFR Part 60 Subpart III and at 40 CFR § 89.112. Due to the very low emissions from these engines, the fact that these will operate only intermittently, that non-emergency use operation is limited to 100 hours per year, and the availability of engines that are certified to achieve this emission level, and considering the nature of the certification test procedure for the nonroad engine emission standards, IU proposes that an equipment design standard rather than an emission rate limit is an appropriate form of expression for the PM/PM10/PM2.5 BACT requirements for the fire pump booster engine and the emergency generator engine.


5.16.2  Emergency Engines NOx BACT Analysis

5.16.2.1 NOx BACT Baseline

As discussed previously, the emergency fire pump booster engine and the emergency generator engine will be affected facilities subject to the standards for emergency engines under 40 CFR Part 60 Subpart IIII. The minimum standards that would meet BACT requirements for NOx emissions from these engines are as follows:

- The fire water pump booster engine, pursuant to 40 CFR § 60.4205(c), will be required to meet the NOx and non-methane hydrocarbons emissions standard established for nonroad engines of the same model year pursuant to Table 4 of subpart IIII. The emission standard is a specification of 4.0 g/bhp-hr, as determined by the engine manufacturer using the nonroad engine testing procedures set forth at 40 CFR §§ 89.401 to 89.424 and at Table 4 of subpart IIII.
- The emergency generator engine, pursuant to 40 CFR § 60.4205(b), will be required to meet the NOx and non-methane hydrocarbons emissions standard established for nonroad engines of the same model year 40 CFR § 60.4202. Per 40 CFR §60.4202 (b)(2), specific limitations in 40 CFR §§ 89.112 and 89.113 are applicable to the emergency engine that is not a fire pump. The emission standard is a specification of 6.4 g/kW-hr, as determined by the engine manufacturer using the nonroad engine testing procedures set forth at 40 CFR §§ 89.401 to 89.424.

5.16.2.2 Step 1 – Identify Available Control Options

Identified control technologies and techniques for NOx emissions from compression-ignition RICE include the following:

- Injection timing retard, also called ignition timing retard, which involves delaying the fuel injection point in each engine cycle such that the heat release from fuel combustion occurs during the cylinder expansion. Lower NOx emissions are achieved by reducing the peak combustion temperature;
- Exhaust gas recirculation, which involves retaining or re-introducing a fraction of the exhaust gases. Lower NOX emissions are achieved by reducing the peak combustion temperature and by reducing the amount of available molecular oxygen;
- NOx adsorber technology, which typically utilizes alkali or alkaline earth metal catalysts to adsorb NOx on the catalyst surface under the fuel-lean and oxygen-rich conditions typical of diesel engine exhaust. Periodically, the catalyst bed is subjected to fuel-rich exhaust in order to desorb the NOX and regenerate the catalyst. The desorbed NOx is catalytically reduced over a second catalyst, typically platinum and rhodium; and
- SCR for NOX reduction.

5.16.2.3 Step 2 – Eliminate Technically Infeasible Options

All of the identified control options are assumed to be technically feasible.
5.16.2.4 Step 3 – Rank Feasible Control Options

The third-ranked control option for NO\textsubscript{X} emissions comprises the use of internal combustion engines certified by the engine manufacturer to meet the applicable NSPS emission standards for non-road, compression-ignition engines. Engines meeting these standards may use multiple in-engine control technologies including injection timing retard and exhaust gas recirculation.

The second-ranked control option for NO\textsubscript{X} emissions involves the use of SCR in conjunction with the third-ranked control option. For the purposes of this BACT analysis, it is assumed that an 80 percent reduction in NO\textsubscript{X} emissions is achievable with this control option. This likely overstates the achievable emission reduction by a significant amount, as the engine will have very little time operating under the steady-state conditions favorable for SCR and oxidation catalyst system performance.

The highest-ranked control option for NO\textsubscript{X} emissions involves the use of catalyzed diesel particulate filters and NO\textsubscript{X} adsorber technology in conjunction with the third-ranked control option. For the purposes of this BACT analysis, it is assumed that 90 percent emission reduction is achievable.

5.16.2.5 Step 4 – Evaluate Feasible Control Options

Third-ranked control option will not cause any adverse energy, environmental, or economic impacts. The higher-ranked control options will cause adverse impacts that warrant their exclusion as the basis for establishing NO\textsubscript{X} BACT limits from the fire pump booster engine and the emergency generator engine. The adverse impacts include energy impacts, due to reduced energy efficiency attributable to increased pressure drop, and environmental impacts associated with catalyst disposal. These adverse energy and environmental impacts are minimal.

The adverse economic impacts that would result from requiring catalytic add-on controls for an emergency use, internal combustion engine would be significant. Economic analyses prepared by U.S. EPA in its rulemaking for NSPS subpart IIII showed that, for emergency use engines, the cost effectiveness of SCR is more than $100,000 per ton of NO\textsubscript{X} reduction, and the cost of catalyzed diesel particulate filters and NO\textsubscript{X} adsorbers are more than $20,000 per ton of total NO\textsubscript{X} and VOC emission reduction.\textsuperscript{72} Considering the minimal environmental benefit that would result, and the adverse energy, economic and environmental impacts described above, these controls are rejected as BACT.

5.16.2.6 Step 5 – Establish BACT

The fire pump booster engine and the emergency generator engine to be installed at the HBI Facility will be certified by the equipment manufacturer to meet the applicable emission standards for nonroad, compression-ignition engines, as codified in 40 CFR Part 60 Subpart IIII and at 40 CFR § 89.112. Subpart IIII also limits the operation of the emergency engines for non-emergencies to less than 100 hours per year. Due to the very low emissions from these engines, the fact that these will operate only intermittently, and the availability of engines that are

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certified to achieve this emission level, and considering the nature of the certification test procedure for the nonroad engine emission standards, IU proposes that an equipment design standard rather than an emission rate limit is an appropriate form of expression for the NO\textsubscript{X} BACT requirements for the fire pump booster engine and the emergency generator engine.

**5.16.3 Emergency Engines CO BACT Analysis**

**5.16.3.1 CO BACT Baseline**

As discussed previously, emergency fire pump booster engine and emergency generator engine will be affected facilities subject to the standards for emergency engines under 40 CFR Part 60 Subpart III. The minimum standards that would meet BACT requirements for CO emissions from these engines are as follows:

- The fire water pump booster engine, pursuant to 40 CFR § 60.4205(c), will be required to meet the CO emission standard established for nonroad engines of the same model year pursuant to Table 4 of subpart III. The emission standard is a specification of 2.6 g/bhp-hr, as determined by the engine manufacturer using the nonroad engine testing procedures set forth at 40 CFR §§ 89.401 to 89.424 and at Table 4 of subpart III.
- The emergency generator engine, pursuant to 40 CFR § 60.4205(b), will be required to meet the CO emission standard established for nonroad engines of the same model year 40 CFR § 60.4202. Per 40 CFR §60.4202 (b)(2), specific limitations in 40 CFR §§ 89.112 and 89.113 are applicable to the emergency engine that is not a fire pump. The emission standard is a specification of 3.5 g/kW-hr, as determined by the engine manufacturer using the nonroad engine testing procedures set forth at 40 CFR §§ 89.401 to 89.424.

**5.16.3.2 Steps 1 – 4**

Potentially available control technologies and techniques for CO emissions include the combustion controls identified as options for VOC (as PM) control in sub-section 5.16.1.2. All of these technologies are assumed to be technically feasible. The baseline control option, using the internal combustion engines certified by the engine manufacturer to meet the applicable NSPS emission standards for non-road, compression-ignition engines, will result in potential CO emissions of 4.22 tons per year from the fire pump booster engine and the emergency generator engine. The top-ranked control option - addition of an oxidation catalyst - may be able to achieve a CO emission rate on the order of 0.42 tons per year, but is rejected as BACT due to its adverse energy, environmental, and economic impacts and its minimal environmental benefit, as discussed in the engine PM BACT analysis.

**5.16.3.3 Step 5 – Establish BACT**

The fire pump booster engine and the emergency generator engine to be installed at the HBI Facility will be certified by the equipment manufacturer to meet the applicable emission standards for nonroad, compression-ignition engines, as codified in 40 CFR Part 60 Subpart III and at 40 CFR § 89.112. Due to the very low emissions from these units, the fact that these will operate only intermittently, that non-emergency use operation is limited to 100 hours per year, and the availability of engines that are certified to achieve this emission level, and considering the nature of the certification test procedure for the nonroad engine emission standards, SRP
proposes that an equipment design standard rather than an emission rate limit is an appropriate form of expression for the CO BACT requirements for the fire pump booster engine and the emergency generator engine.

5.16.4 Emergency Engines GHG BACT Analysis

The fire pump booster engine and the emergency generator engine will result in GHG emissions from combustion of diesel fuel by the engines during those brief periods when these will operate. The GHG PTE, assuming 500 hours of operation per year for each engine, is 79 tons of CO$_2$e per year for the fire pump booster engine and 683 tons per year for the emergency generator engine or about 0.0005% of the source-wide GHG PTE. The baseline emission level for these engines, representing proper equipment design and operation and the use of diesel fuel, is a GHGs emission factor of 163.6 lb/MMBtu of fuel burned. On a mass basis, emissions of CH$_4$ and N$_2$O comprise 0.005 percent of total GHG emissions from the engines, with the remainder being CO$_2$.

5.16.4.1 GHG BACT Baseline

There are no applicable NSPS or NESHAP rules that would establish a baseline emission rate for GHG emissions from the emergency engines.

5.16.4.2 Steps 1 – 4

The only identified control technologies for GHG emissions from the emergency diesel engines are oxidation catalyst (for control of CH$_4$ emissions)$^{73}$ and CCS (for control of CO$_2$ emissions). Each of these technologies is assumed to be technically feasible. The use of oxidation catalyst could achieve some level of CH$_4$ emission reduction, but is rejected as BACT due to its adverse energy, environmental, and economic impacts and its minimal environmental benefit, as discussed in the PM BACT analysis above. Similarly, CCS is rejected as BACT because it is infeasible, and even if feasible, would not be cost effective, as discussed in the GHG BACT discussion for the reformer.

5.16.4.3 Step 5 – Establish BACT

No available control strategy more effective than the inherent engine design has been identified as BACT for GHG emissions from the fire pump booster engine and the emergency generator engine at the HBI Facility. Therefore, IU proposes that an emission limit of 163.6 lb/MMBtu of fuel burned be established for GHG emissions from these emergency engines, on a CO$_2$e basis, with compliance to be demonstrated using the procedures of 40 CFR § 98.33 (as of August 4, 2017).

5.17 Equipment Leaks GHG BACT Analysis

The Project will involve installation of a number of equipment components such as valves and flanges that supply natural gas to the HBI core plant. Some of the components have the potential to leak, resulting in fugitive emissions of CH$_4$ which is a GHG with a global warming potential

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$^{73}$ Oxidation catalyst will increase GHG emissions on a mass basis but due to the differing global warming potentials of CH$_4$ and CO$_2$, oxidation of CH$_4$ is nonetheless considered a GHG control option.
(GWP) of 25. This section presents the required GHG BACT analysis for equipment leaks associated with the natural gas supply system piping.

Table 5-15 presents a preliminary estimate of the number of equipment components that have the potential to emit fugitive natural gas along with an estimate of the uncontrolled methane emissions from these components.

### Table 5-15. PTE of CH₄ from the Project Equipment Components

<table>
<thead>
<tr>
<th>Component Type</th>
<th>Quantity</th>
<th>CH₄ PTE (tons/year)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Valves – Gas Service</td>
<td>22</td>
<td>1.23</td>
</tr>
<tr>
<td>Pressure Relief Valves – Gas Service</td>
<td>7</td>
<td>6.84</td>
</tr>
<tr>
<td>Connectors</td>
<td>568</td>
<td>9.77</td>
</tr>
<tr>
<td><strong>Total Emissions =</strong></td>
<td></td>
<td><strong>17.84</strong></td>
</tr>
</tbody>
</table>

#### 5.17.1 GHG BACT Baseline

There are no state, local or federal regulations applicable to the GHG emissions from the natural gas supply piping in the proposed Project. Therefore, there is no “BACT baseline” for this unit-pollutant group.

#### 5.17.2 Step 1 – Identify Available Control Options

The only potentially available control strategy identified to reduce fugitive emissions from equipment leaks is a leak detection and repair (LDAR) program. LDAR is a work practice that is commonly used in the petroleum refining and synthetic organic chemical manufacturing industry to reduce VOC emissions from equipment leaks. Such a program involves periodic monitoring to identify components with leak rates above a set threshold, and when such components are identified, efforts are made to repair the component and thereby reduce or eliminate leaks. There are no other available control options for reducing fugitive emissions from equipment leaks.

#### 5.17.3 Step 2 – Eliminate Technically Infeasible Options

The use of an LDAR program is a feasible means of reducing fugitive CH₄ emissions from leaking components.

#### 5.17.4 Step 3 – Rank Control Options

The costs and effectiveness of LDAR programs vary according to the leak repair threshold selected. For purposes of this BACT analysis, it is assumed that leak repair thresholds equivalent to those required 40 CFR 63, subpart H would be utilized. On average, these thresholds are estimated to reduce emissions by 91% relative to the uncontrolled fugitive emissions from leaking components. This is the most effective feasible control option available to reduce fugitive CH₄ emissions from the natural gas piping.

#### 5.17.5 Step 4 – Evaluate Feasible Control Options

Table 5-16 summarizes the costs and benefits of implementing an LDAR program on the planned Project to reduce fugitive CH₄ emissions from natural gas piping leaks. As shown in the table, the costs of implementing such a program are excessive relative to the emissions.
reductions that would result. This table is based on the premise that a VOC control cost threshold of $20,000/ton is excessive. Crediting this cost threshold to the LDAR VOC emissions reductions results in a GHG emissions control cost (on a CO$_2$e basis) of $1,040/ton.

Table 5-16. Control Costs for Natural Gas LDAR Program$^{74}$

<table>
<thead>
<tr>
<th>Cost Category / Element</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Annualized Capital Costs - $/year (Annualized cost of capital required to establish LDAR program)</td>
<td>$10,835</td>
</tr>
<tr>
<td>Annual O&amp;M Costs - $/year (Annual direct and indirect costs to operate LDAR program)</td>
<td>$56,022</td>
</tr>
<tr>
<td>Gross Annualized Costs - $/year</td>
<td>$66,857</td>
</tr>
<tr>
<td>Amount of NG recovered (ton/year)</td>
<td>16.42</td>
</tr>
<tr>
<td>Amount of CH$_4$ Controlled (T/yr)</td>
<td>15.97</td>
</tr>
<tr>
<td>Amount of VOC Controlled (T/yr)</td>
<td>0.44</td>
</tr>
<tr>
<td>Value of NG “recovered”</td>
<td>$2,675</td>
</tr>
<tr>
<td>Credit for VOC @ $20,000 T</td>
<td>$8,850</td>
</tr>
<tr>
<td>Total Net Annualized Costs</td>
<td>$55,332</td>
</tr>
<tr>
<td>Cost Effectiveness ($/ton CO$_2$e)</td>
<td>$139</td>
</tr>
</tbody>
</table>

5.17.6 Step 5 – Establish BACT

As described in the reformer BACT section, a cost effectiveness of $139 per ton of CO$_2$e results in unreasonable economic impacts. Thus, based on the excessive costs and limited benefits of implementing an LDAR program to reduce fugitive CH$_4$ emissions from leaking components, IU concludes that it is unreasonable to require such a program as BACT for reducing fugitive emissions from the natural gas supply system. IU further concludes that BACT for fugitive CH$_4$ emissions from leaking components is good industrial design coupled with routine operation and maintenance of the equipment consistent with the all applicable safety standards.

5.18 Oxide Handling Systems (Enclosed) PM/PM10/PM2.5 BACT Analysis

This section presents the required PM/PM10/PM2.5 BACT analyses for the enclosed iron ore pellets (oxide) handling operations. A list of the oxide handling operations that are enclosed is provided in Table 3-7. The enclosed oxide handling points include the following:

(a) Transfer of oxide from one conveyor to another.
(b) Transfer of oxide to lumps screen to three oxide day bins.
(c) Oxide day bins to conveyors.

(d) Conveyors to screens.
(e) Screening transfers.

5.18.1 PM/PM10/PM2.5 BACT Baseline

There are no state, local or federal regulations applicable to PM/PM10/PM2.5 emissions from the transfer and handling of iron ore pellets at a HBI Facility. Therefore, there is no “BACT baseline” for this operation.

5.18.2 Step 1 – Identify Available PM/PM10/PM2.5 Control Options

A summary of the precedents from U.S. EPA’s RBLC database and other known permit precedents for the enclosed oxide handling operations is presented in Table 5-17.

<table>
<thead>
<tr>
<th>RBLC ID/State</th>
<th>Facility Name</th>
<th>Permit Date</th>
<th>Process Description</th>
<th>Control</th>
<th>Emission Limit gr/dscf</th>
</tr>
</thead>
<tbody>
<tr>
<td>IN-0185</td>
<td>Mag Pellet LLC</td>
<td>4/24/2014</td>
<td>Oxide pellet loadout system</td>
<td>Baghouses</td>
<td>0.0020</td>
</tr>
<tr>
<td>TX-0725</td>
<td>Voestalpine Texas DRI facility</td>
<td>3/18/2014</td>
<td>Oxide pellet transfer and dedusting</td>
<td>Baghouses</td>
<td>0.0020</td>
</tr>
<tr>
<td>IN-0167</td>
<td>Magnetation LLC</td>
<td>4/16/2013</td>
<td>Oxide pellet storage and unloading system</td>
<td>Baghouse</td>
<td>0.0020</td>
</tr>
<tr>
<td>MN-0085</td>
<td>Essar Steel Minnesota LLC</td>
<td>5/10/2012</td>
<td>Pellet screening and handling</td>
<td>Baghouse</td>
<td>0.0020</td>
</tr>
<tr>
<td>LA-0248</td>
<td>Consolidated Environmental DRI facility (never built)</td>
<td>1/27/2011</td>
<td>Iron oxide day bins</td>
<td>Baghouse</td>
<td>0.0020</td>
</tr>
</tbody>
</table>

The oxide handling and screening operations result in release of small amount particulate matter emissions. The potential control options for controlling emissions from the oxide are identified below:

(a) Fabric filter (baghouse)
(b) Electrostatic precipitator (ESP)
(c) Venturi scrubber
(d) Cyclone
(e) Wet suppressions
(f) Enclosures

Some of the control options listed here are described in the reformer section. Wet suppression and enclosures are described below.

Wet Suppression – This technology involves use of fine mist of water to reduce particle generation from material handling operations. The wetted material becomes heavier and quickly settles reducing air borne emissions. Wet suppression may also increase moisture content and reduce emissions.

Enclosures – Enclosures or covers are used for conveyor systems to prevent dust particles from entraining in the air stream including at various conveyor drop points to another conveyor or handling equipment.
5.18.3  **Step 2 – Eliminate Technically Infeasible PM/PM10/PM2.5 Controls**

All of the identified control technologies are technically feasible for the enclosed oxide handling operations. Use of enclosure here represents the baseline case.

5.18.4  **Step 3 – Rank PM/PM10/PM2.5 Control Options**

The particulate matter control strategies selected for the proposed enclosed oxide handling operations that are considered technically feasible and associated control efficiencies are:

(a) Baghouse – 99.9%
(b) ESP – 99.5%
(c) Venturi scrubber – 99%
(d) Enclosure or hoods – ~95%
(e) Wet suppression - 95%
(f) Cyclones – 80%

5.18.5  **Step 4 – Evaluate Feasible PM/PM10/PM2.5 Control Options**

The oxide handling operations that are to be enclosed will be exhausted to various baghouses as shown in Appendix C. Use of baghouse is the top control technology and will not have any material adverse energy, environmental or economic impacts. Therefore, it is appropriate that use of baghouses form the basis for establishing the PM/PM10/PM2.5 BACT limits for the proposed equipment.

5.18.6  **Step 5 – Establish PM/PM10/PM2.5 BACT**

The use of baghouse represents the top ranked control option for the oxide handling operations with enclosures. The following Table 5-18 presents the proposed PM/PM10/PM2.5 limits for the enclosed oxide handling operations that are to be equipped with baghouses.

**Table 5-18. PM/PM10/PM2.5 BACT Limits for Oxide Handling Operations Enclosed**

<table>
<thead>
<tr>
<th>Emission Point</th>
<th>Emission Limit (lb/hour)*</th>
<th>Basis (gr/dscf)**</th>
</tr>
</thead>
<tbody>
<tr>
<td>TR-1 Oxide Transfer I</td>
<td>PM/PM10/PM2.5 - 0.11</td>
<td>PM - 0.0025</td>
</tr>
<tr>
<td>TR-6 Oxide Transfer II</td>
<td>PM/PM10/PM2.5 - 0.06</td>
<td>PM - 0.0025</td>
</tr>
<tr>
<td>TR-7 Oxide Transfer III</td>
<td>PM/PM10/PM2.5 - 0.06</td>
<td>PM - 0.0025</td>
</tr>
<tr>
<td>TR-10 Oxide Day Bin w/2 baghouses</td>
<td>PM/PM10/PM2.5 - 0.43</td>
<td>PM - 0.0025</td>
</tr>
<tr>
<td>SR-1 Screen Building</td>
<td>PM/PM10/PM2.5 - 0.51</td>
<td>PM - 0.0025</td>
</tr>
<tr>
<td>TR-13 Conveyor to Bucket Elevator</td>
<td>PM/PM10/PM2.5 - 0.06</td>
<td>PM - 0.0025</td>
</tr>
<tr>
<td>TR-14 Coating Storage and Mixing</td>
<td>PM/PM10/PM2.5 - 0.11</td>
<td>PM - 0.0025</td>
</tr>
</tbody>
</table>

*Derivations of the emissions limitations above are provided in Appendix C detailed emissions calculations.
**The basis for establishing the emissions limitations were provided by the supplier for the equipment.

Compliance with these limits will be demonstrated using by meeting the equipment design specifications as noted in Appendix C and regular inspection and monitoring of the control devices.

IU’s proposed PM/PM10/PM2.5 BACT limitations are based on the outlet grain loading information provided by the baghouse equipment supplier. Due to lack of testing requirements
for the lower PM/PM10/PM2.5 grain loading rates in Table 5-17 above, we were unable to confirm whether the equipment is in compliance with the lower rates and did not consider the lower rate as PM/PM10/PM2.5 BACT limitations for these operations.

5.19 Building Enclosure Evaluation for Oxide Transfers and Storage Operations PM/PM10/PM2.5 BACT Analysis

Several oxide transfer and storage operations listed in Table 3-8, Table 3-9, Table 3-10, and Table 3-11 will occur in the open/non-enclosed areas at the site. As one of the control option, IU evaluated enclosing the open oxide transfer and storage operations inside a large storage building. To be conservative, in addition to the oxide transfer and handling operations, we added emissions from the oxide lumps, oxide fines, and REMET transfer and storage operations in the cost effectiveness calculations without altering the overall building cost. This section presents an analysis for use of building enclosure for purposes of BACT for PM/PM10/PM2.5 for the oxide transfer and storage operations.

5.19.1 PM/PM10/PM2.5 BACT Baseline

There are no state, local or federal regulations applicable to PM/PM10/PM2.5 emissions from the open transfer and storage of iron ore pellets. Therefore, there is no “BACT baseline” for these operations.

5.19.2 Step 1 – Identify Available PM/PM10/PM2.5 Control Options

The oxide handling and storage operations result in airborne particulate matter from the wind entrained dust during material transfers at the various drop points and wind erosion from the stockpiles. One of the control option is to enclose all these operations inside a building to reduce exposure to wind. Specifically, the voestalpine facility in Portland Texas, includes an oxide stockpile and handling operation inside an enclosed storage building.75

5.19.3 Step 2 – Eliminate Technically Infeasible PM/PM10/PM2.5 Controls

For purposes of this analysis, we conservatively assumed that it is technically feasible to enclose all of the open oxide, lumps, fines, and REMET transfer and storage operations inside a building. We did not evaluate whether there were any technical feasibility concerns regarding this control option at this time.

5.19.4 Step 3 – Rank PM/PM10/PM2.5 Control Options

The particulate matter control strategy for the proposed open transfer and storage of oxide and other materials is building enclosure with control efficiency of 95%.

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75 See permit number 108113 and PSD TX1344 (RBLC ID TX-0725) issued by Texas Commission on Environmental Quality (TCEQ) on March 18, 2014 (modified March 1, 2016). The permit lists “use of enclosed storage” for iron ore pellets. However, the BACT analysis in the permit application (dated August 26, 2013) only proposed use of “chemical surface stabilizer” for oxide and HBI storage piles.
5.19.5 Step 4 – Evaluate Feasible PM/PM10/PM2.5 Control Options

As shown in Appendix C, the engineering contractor for the project provided preliminary estimated cost for an oxide (excluding lumps, fines, REMET handling and storage) storage building at $80 million. For purposes of this analysis, we conservatively assumed that all of the oxide, lumps, fine, and REMET transfer and stockpiles can occur inside this building. As the building will have openings for ventilation and equipment, we assumed a 95% control efficiency for particulate matter emissions from the oxide transfer and storage operations. We also conservatively did not include any operating and maintenance cost for the building enclosure. The annualized cost of the building was developed using a capital recovery factor for 20 year building life and 7% interest rate. Using uncontrolled PM emissions from the oxide, lumps, fines, and REMET for transfer and stockpile operations of 49.21 tons per year, the expected reduction in PM is 46.75 tons per year (at 95% control efficiency). This results in cost effectiveness of over $161,000 per ton of PM controlled for use of the building enclosure. Use of building enclosure will have adverse economic impact for the project. Therefore, building enclosure is deemed cost prohibitive and rejected as BACT for PM/PM10/PM2.5.

5.19.6 Step 5 – Establish PM/PM10/PM2.5 BACT

Based on the analysis for a building enclosure presented here, enclosing the proposed oxide transfer and storage operations is rejected as BACT for fugitive PM/PM10/PM2.5. Other options for control of fugitive emissions from these operations is described further in this section.

5.20 Oxide Transfers (open) Operations PM/PM10/PM2.5 BACT Analysis

This section presents the PM/PM10/PM2.5 BACT analysis for the open oxide transfer operations. A list of the open oxide transfer points is provided in Table 3-8 and Table 3-9. The open oxide transfer points include the following:

(a) Transfer of oxide to and from conveyors to stacker/reclaim machine.
(b) Transfer of oxide to and from stacker/reclaim machine to and from oxide stockpiles.
(c) Transfer of oxide lumps, fines, REMET from conveyors to stockpiles.
(d) Transfer of oxide lumps, fines, REMET from front end loaders (FEL) reclaim to truck/hopper.

5.20.1 PM/PM10/PM2.5 BACT Baseline

There are no state, local or federal regulations applicable to PM/PM10/PM2.5 emissions from the open transfer and handling of iron ore pellets. Therefore, there is no “BACT baseline” for this operation.

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76 Ohio EPA’s Reasonably Available Control Measures (RACM) Rule 3745-17-08 document on page 2-42 states that “[d]ue to [design] specificity, it is hard to place an exact efficiency rating or cost estimate on the use of storage silos or buildings.” Also, Table 2.1.2-8 lists control efficiency range of 95%-100% for wind disturbance control for storage piles using silos. We used the lower end of this range for this analysis.
5.20.2   Step 1 – Identify Available PM/PM10/PM2.5 Control Options

The oxide handling operations result in release of small amount particulate matter emissions. Similar to the discussion under 5.18.2, the potential control options for controlling emissions from the open oxide transfer operations are identified below:

(a) Fabric filter (baghouse)
(b) Electrostatic precipitator (ESP)
(c) Venturi scrubber
(d) Cyclone
(e) Water or chemical suppressants
(f) Enclosures
(g) Windshield

5.20.3   Step 2 – Eliminate Technically Infeasible PM/PM10/PM2.5 Controls

The open transfer of oxide and other materials by definition results in particulate matter emissions that are fugitive. As previously discussed in section 5.19, use of a building enclosure is infeasible and unreasonable for these operations. OAC 3745-31-01(UU) defines fugitive emissions as “…those emissions that cannot reasonably pass through a stack, chimney.” Since these operations occur in open, it is unreasonable to capture emissions from these open transfers. Therefore, add-on control technologies (baghouse, ESP, scrubber, cyclone) are not technically feasible for these operations. In addition, due to specific nature of the operations, *i.e.* mobile equipment such as stacker/reclaim machine, FEL etc., use of hoods or capture system is also not technically feasible. For materials transfers from the proposed FELs to either trucks or hopper, addition of water sprays is not feasible due to mobile nature of the equipment.

5.20.4   Step 3 – Rank PM/PM10/PM2.5 Control Options

The particulate matter control strategies selected for the proposed open transfer of oxide and other materials that are considered technically feasible and associated control efficiencies are use of water or chemical suppressants at 95% control efficiency.

5.20.5   Step 4 – Evaluate Feasible PM/PM10/PM2.5 Control Options

As shown in Appendix C, the open oxide transfer points will use water or chemical suppressants or windshields (in case of REMET pile) to control fugitive PM/PM10/PM2.5 emissions. Use of these controls are the top control technologies and will not have any material adverse energy, environmental or economic impacts. Therefore, it is appropriate that use of water or chemical suppressants or windshields form the basis for establishing the fugitive PM/PM10/PM2.5 BACT requirements for the proposed open oxide and REMET transfer equipment.

5.20.6   Step 5 – Establish PM/PM10/PM2.5 BACT

Equipment design or work practice requirements are acceptable under the definition of BACT when technological or economic limitations on the application of measurement methodology would make the imposition of an emissions standard infeasible. That criterion is met with respect to particulate matter emissions from the open oxide transfer operations. The use of water or chemical suppressants or windshields represents the top ranked control option for the open oxide,
lumps, fines, and REMET transfer operations and is deemed as BACT for fugitive
PM/PM10/PM2.5 emissions from these operations.

5.21 Oxide Stockpiles PM/PM10/PM2.5 BACT Analysis

This section presents the required PM/PM10/PM2.5 BACT analyses for the oxide, lumps, fines, and REMET materials stockpiles. A list of the oxide and other oxide materials stockpiles is provided in Table 3-10 and Table 3-11. These stockpiles include the following:

(a) Two oxides stockpiles.
(b) Stockpiles for oxide lumps, fines, and REMET.

5.21.1 PM/PM10/PM2.5 BACT Baseline

There are no state, local or federal regulations applicable to PM/PM10/PM2.5 emissions from the oxide stockpiles. Therefore, there is no “BACT baseline” for this operation.

5.21.2 Step 1 – Identify Available PM/PM10/PM2.5 Control Options

A summary of the precedents from U.S. EPA’s RBLC database and other known permit precedents for the oxide stockpiles is presented in Table 5-19.

Table 5-19. Summary of PM/PM10/PM2.5 BACT Precedence for Oxide Stockpiles

<table>
<thead>
<tr>
<th>RBL ID/ State</th>
<th>Facility Name</th>
<th>Permit Date</th>
<th>Process Description</th>
<th>Control</th>
<th>Emission Limit</th>
</tr>
</thead>
<tbody>
<tr>
<td>TX-0725</td>
<td>Voestalpine Texas DRI facility</td>
<td>3/18/2014</td>
<td>Pellet storage</td>
<td>Enclosed storage</td>
<td>NA</td>
</tr>
<tr>
<td>MN-0085</td>
<td>Essar Steel Minnesota LLC</td>
<td>5/10/2012</td>
<td>Oxide product loadout</td>
<td>Visible Emissions</td>
<td>VE - 5%</td>
</tr>
<tr>
<td>LA-0248</td>
<td>Consolidated Environmental DRI facility (never built)</td>
<td>1/27/2011</td>
<td>Iron ore pellet storage piles</td>
<td>Wet suppression water sprays</td>
<td>PM10 - 5.6 lb/hour</td>
</tr>
</tbody>
</table>

Open oxide, lumps, fines, and REMET stockpiles result in release of small amount particulate matter emissions from wind erosion. The potential control options for controlling emissions from the open stockpiles are identified below:

(a) Chemical stabilization/watering
(b) Enclosures
(c) Windshield

Use of enclosed storage as BACT for stockpiles was eliminated in section 5.19 as it was deemed cost prohibitive. Therefore, use of enclosure is not considered further here.

5.21.3 Step 2 – Eliminate Technically Infeasible PM/PM10/PM2.5 Controls

The open storage of oxide and other materials by definition results in particulate matter emissions that are fugitive. OAC 3745-31-01(UU) defines fugitive emissions as “…those emissions that cannot reasonably pass through a stack, chimney.” Since these operations occur in open, it is not reasonable to capture emissions from these stockpiles. Therefore, use of chemical
stabilization/watering and windshield are the technically feasible control options for the oxide, lumps, and fines storage stockpiles. Use of chemical stabilization/watering is not technically feasible for REMET stockpile as there will be risk of explosion on contact with water.

5.21.4 Step 3 – Rank PM/PM10/PM2.5 Control Options

The particulate matter control strategies selected for the proposed open oxide and other materials stockpiles that are considered technically feasible and associated control efficiencies are:

- Chemical stabilization/watering - 99%
- Windshield – 30%

5.21.5 Step 4 – Evaluate Feasible PM/PM10/PM2.5 Control Options

As shown in Appendix C, the open oxide, lumps, and fines stockpiles will use chemical stabilization/watering by application of chemicals to control fugitive PM/PM10/PM2.5 emissions. For REMET stockpile, windshields will be used to control fugitive particulate matter emissions. Use of these controls are the top control technologies and will not have any material adverse energy, environmental or economic impacts. Therefore, it is appropriate that use of chemical stabilization/watering or windshields form the basis for establishing the fugitive PM/PM10/PM2.5 BACT for the proposed open oxide and other materials stockpiles.

5.21.6 Step 5 – Establish PM/PM10/PM2.5 BACT

Equipment design or work practice requirements are acceptable under the definition of BACT when technological or economic limitations on the application of measurement methodology would make the imposition of an emissions standard infeasible. That criterion is met with respect to particulate matter emissions from the open oxide, lumps, fines, and REMET stockpiles operations. The use of chemical stabilization/watering or windshields represents the top ranked control option for the open stockpiles and constitute BACT for fugitive PM/PM10/PM2.5 emissions.

5.22 HBI Handling Systems (Enclosed) PM/PM10/PM2.5 BACT Analysis

This section presents the required PM/PM10/PM2.5 BACT analysis for the enclosed HBI handling systems. A list of the enclosed HBI handling systems is provided in Table 3-14. The enclosed HBI handling points include the following:

(a) Transfer of HBI from one conveyor to another.
(b) Transfer of HBI to loadout bins.
(c) HBI truck loadout building exhaust.

5.22.1 PM/PM10/PM2.5 BACT Baseline

There are no state, local or federal regulations applicable to PM/PM10/PM2.5 emissions from the transfer and handling of HBI. Therefore, there is no “BACT baseline” for this operation.
5.22.2 Step 1 – Identify Available PM/PM10/PM2.5 Control Options

A summary of the precedents from U.S. EPA’s RBLC database and other known permit precedents for the HBI handling is presented in Table 5-20.

<table>
<thead>
<tr>
<th>RBLC ID/ State</th>
<th>Facility Name</th>
<th>Permit Date</th>
<th>Process Description</th>
<th>Control</th>
<th>Emission Limit gr/dscf</th>
</tr>
</thead>
<tbody>
<tr>
<td>TX-0725</td>
<td>Voestalpine Texas DRI facility</td>
<td>3/18/2014</td>
<td>HBI cooling conveyors</td>
<td>Wet scrubber</td>
<td>0.0079</td>
</tr>
</tbody>
</table>

HBI handling and screening systems result in release of small amount particulate matter emissions. The potential control options for controlling emissions from the HBI are identified below:

(a) Fabric filter (baghouse)
(b) Electrostatic precipitator (ESP)
(c) Venturi scrubber
(d) Cyclone
(e) Wet suppressions
(f) Enclosures

5.22.3 Step 2 – Eliminate Technically Infeasible PM/PM10/PM2.5 Controls

DRI is formed in a reduced oxygen atmosphere, and its particles are known to react to oxygen when exposed to the atmosphere. This exothermal reaction is known to cause fires. Therefore, the nature of the DRI particulates makes the application of a baghouse to be a significant safety hazard and the use of a baghouse for cleaning the HBI handling is considered technically infeasible.

DRI particulates have high iron content. ESPs are especially sensitive to electrical resistivity, and iron particles adhere very strongly to the ESP collection plates. This makes it difficult to remove the iron particles, which quickly reduces ESP efficiency. Additionally, the application of an ESP creates a significant fire safety hazard when handling the captured DRI particles if exposed to air. The use of an ESP for cleaning the HBI handling exhaust is considered technically infeasible.

As is the case for the use of a baghouse or ESP, the use of a cyclone for removal of DRI particles creates a significant fire safety hazard when handling the captured DRI particles. The use of a cyclone for cleaning the exhaust from HBI handling is considered technically infeasible.

The use of a venturi scrubber is considered technically feasible because the DRI particulates are collected wet, and do not create a fire safety hazard. In addition, wet suppression and enclosures are also feasible for HBI handling operations.

5.22.4 Step 3 – Rank PM/PM10/PM2.5 Control Options

The particulate matter control strategies selected for the proposed enclosed HBI handling operations that are considered technically feasible and associated control efficiencies are:
(a) Venturi scrubber – 99%
(b) Enclosure or hoods – ~95%
(c) Wet suppression - 95%

5.22.5 Step 4 – Evaluate Feasible PM/PM10/PM2.5 Control Options

The HBI handling systems that are to be enclosed will be exhausted to various venturi scrubbers as shown in Appendix C. Use of particulate matter control scrubbers is the top control technology and will not have any material adverse energy, environmental or economic impacts. Therefore, it is appropriate that use of scrubber form the basis for establishing the PM/PM10/PM2.5 BACT limits for the proposed equipment.

5.22.6 Step 5 – Establish PM/PM10/PM2.5 BACT

The use of scrubber represents the top ranked control option for the HBI handling systems with enclosures. The following Table 5-21 presents the proposed PM/PM10/PM2.5 limits for the enclosed HBI handling systems that are to be equipped with scrubbers.

Table 5-21. PM/PM10/PM2.5 BACT Limits for HBI Handling Systems Enclosed

<table>
<thead>
<tr>
<th>Emission Point</th>
<th>Emission Limit (lb/hour)*</th>
<th>Basis (gr/dscf)**</th>
</tr>
</thead>
<tbody>
<tr>
<td>TR-17 HBI Transfer I</td>
<td>PM/PM10/PM2.5 - 0.10</td>
<td>PM - 0.0025</td>
</tr>
<tr>
<td>TR-18 HBI Transfer II &amp; III</td>
<td>PM/PM10/PM2.5 - 0.10</td>
<td>PM - 0.0025</td>
</tr>
<tr>
<td>TR-23 HBI Transfer tower to loadout</td>
<td>PM/PM10/PM2.5 - 0.06</td>
<td>PM - 0.0025</td>
</tr>
<tr>
<td>TR-24 HBI Transfer to loadout bin</td>
<td>PM/PM10/PM2.5 - 0.06</td>
<td>PM - 0.0025</td>
</tr>
<tr>
<td>TR-25 HBI Truck loadout building</td>
<td>PM/PM10/PM2.5 - 0.10</td>
<td>PM - 0.0025</td>
</tr>
</tbody>
</table>

*Derivations of the emissions limitations above are provided in Appendix C detailed emissions calculations.

**The basis for establishing the emissions limitations were provided by the supplier for the equipment.

Compliance with these limits will be demonstrated using by meeting the equipment design specifications as noted in Appendix C and regular inspection and monitoring of the control devices.

5.23 HBI Transfers (open) Systems PM/PM10/PM2.5 BACT Analysis

This section presents the PM/PM10/PM2.5 BACT analysis for the open HBI transfer systems. A list of the open HBI transfer points is provided in Table 3-15 and Table 3-16. The open HBI transfer points include the following:

(a) Transfer of HBI from conveyor to stacker machine.
(b) Transfer of HBI from stacker machine to HBI stockpile.
(c) Transfer of HBI from reclaim FEL to travelling hoppers.
(d) Transfer of HBI from hoppers to conveyors.
(e) HBI loadout to rail and trucks (partial enclosure).
5.23.1 PM/PM10/PM2.5 BACT Baseline

There are no state, local or federal regulations applicable to PM/PM10/PM2.5 emissions from the open transfer and handling of HBI. Therefore, there is no “BACT baseline” for this operation.

5.23.2 Step 1 – Identify Available PM/PM10/PM2.5 Control Options

HBI transfer systems result in release of small amount particulate matter emissions. Similar to the discussion under 5.20.2, the potential control options for controlling emissions from the open HBI transfer systems are identified below:

(a) Fabric filter (baghouse)
(b) Electrostatic precipitator (ESP)
(c) Venturi scrubber
(d) Cyclone
(e) Water or chemical suppressants
(f) Enclosures
(g) Windshield

5.23.3 Step 2 – Eliminate Technically Infeasible PM/PM10/PM2.5 Controls

The open transfer of HBI by definition results in particulate matter emissions that are fugitive. OAC 3745-31-01(UU) defines fugitive emissions as “…those emissions that cannot reasonably pass through a stack, chimney.” Since these operations occur in open, it is unreasonable to capture emissions from these open transfers. Therefore, add-on control technologies (baghouse, ESP, scrubber, cyclone) are not technically feasible for these operations. In addition, due to specific nature of the operations, i.e. mobile equipment such as stacker/reclaim machine, FEL etc., use of hoods or capture system is also not technically feasible.

5.23.4 Step 3 – Rank PM/PM10/PM2.5 Control Options

The particulate matter control strategies selected for the proposed open transfer of HBI that are considered technically feasible and associated control efficiencies are:

- Water or chemical suppressants - 95%
- Enclosure with doors for truck loadout – 95%
- Enclosure with strip curtains for rail loadout with water sprays – 95%

5.23.5 Step 4 – Evaluate Feasible PM/PM10/PM2.5 Control Options

As shown in Appendix C, the open HBI transfer points will either use water or chemical suppressants to control fugitive PM/PM10/PM2.5 emissions. In addition, transfer of HBI from the loadout bins to the rail and the trucks will occur inside the loadout enclosures. Use of these controls are the top control technologies and will not have any material adverse energy, environmental or economic impacts. Therefore, it is appropriate that use of wet suppression or enclosures form the basis for establishing the fugitive PM/PM10/PM2.5 BACT requirements for the proposed open HBI transfer equipment.
5.23.6 Step 5 – Establish PM/PM10/PM2.5 BACT

Equipment design or work practice requirements are acceptable under the definition of BACT when technological or economic limitations on the application of measurement methodology would make the imposition of an emissions standard infeasible. That criterion is met with respect to particulate matter emissions from the open HBI transfer systems. The use of water or chemical suppressants or enclosures represents the top ranked control option for the open HBI transfer systems and is deemed as BACT for fugitive PM/PM10/PM2.5 emissions from these operations.

5.24 HBI Stockpile PM/PM10/PM2.5 BACT Analysis

This section presents the required PM/PM10/PM2.5 BACT analysis for the proposed HBI stockpile.

5.24.1 PM/PM10/PM2.5 BACT Baseline

There are no state, local or federal regulations applicable to PM/PM10/PM2.5 emissions from the HBI stockpile. Therefore, there is no “BACT baseline” for this operation.

5.24.2 Step 1 – Identify Available PM/PM10/PM2.5 Control Options

A summary of the precedents from U.S. EPA’s RBLC database and other known permit precedents for the HBI stockpile is presented in Table 5-3.

Table 5-22. Summary of PM/PM10/PM2.5 BACT Precedence for HBI Stockpiles

<table>
<thead>
<tr>
<th>RBL Code</th>
<th>Facility Name</th>
<th>Permit Date</th>
<th>Process Description</th>
<th>Control</th>
<th>Emission Limit</th>
</tr>
</thead>
<tbody>
<tr>
<td>TX-0725</td>
<td>Voestalpine Texas DRI facility</td>
<td>3/18/2014</td>
<td>HBI product storage piles</td>
<td>Water sprays, wetting agents</td>
<td>NA</td>
</tr>
</tbody>
</table>

The open HBI stockpile results in release of small amount particulate matter emissions from wind erosion. The potential control options for controlling emissions from the open stockpile are identified below:

(a) Chemical stabilization/watering
(b) Enclosures
(c) Windshield

Use of enclosed storage as BACT was eliminated in section 5.19 as it was deemed cost ineffective. Therefore, use of enclosure is not considered further here.

5.24.3 Step 2 – Eliminate Technically Infeasible PM/PM10/PM2.5 Controls

The open storage of HBI by definition results in particulate matter emissions that are fugitive. OAC 3745-31-01(UU) defines fugitive emissions as “…those emissions that cannot reasonably pass through a stack, chimney.” Since these operations occur in open, it is not reasonable to capture emissions from the open stockpile. Therefore, use of chemical stabilization/watering and windshield are the technically feasible control options for the HBI stockpile.
5.24.4 Step 3 – Rank PM/PM10/PM2.5 Control Options
The particulate matter control strategies selected for the proposed open HBI stockpile that are considered technically feasible and associated control efficiencies are:
- Chemical stabilization/watering - 99%
- Windshield – 30%

5.24.5 Step 4 – Evaluate Feasible PM/PM10/PM2.5 Control Options
As shown in Appendix C, the open HBI stockpile will use chemical stabilization/watering to control fugitive PM/PM10/PM2.5 emissions. Use of this control is the top control technology and will not have any material adverse energy, environmental or economic impacts. Therefore, it is appropriate that use of wet suppression form the basis for establishing the fugitive PM/PM10/PM2.5 BACT for the proposed open HBI stockpile.

5.24.6 Step 5 – Establish PM/PM10/PM2.5 BACT
Equipment design or work practice requirements are acceptable under the definition of BACT when technological or economic limitations on the application of measurement methodology would make the imposition of an emissions standard infeasible. That criterion is met with respect to particulate matter emissions from the open HBI stockpile. The use of chemical stabilization/watering represents the top ranked control option for the open stockpile and constitute BACT for fugitive PM/PM10/PM2.5.

5.25 Front End Loaders Movement on Unpaved Surfaces
PM/PM10/PM2.5 BACT Analysis
This section presents the required PM/PM10/PM2.5 BACT analysis for the fugitive particulate matter emissions from the FELs travel for various materials reclaim activities. The FELs travel on unpaved surfaces in various material stockpile areas. The FEL reclaim activities on unpaved surfaces include the following:

(a) Lumps reclaim and transfer to truck.
(b) Fines reclaim and transfer to truck.
(c) REMET reclaim and transfer to hopper.
(d) HBI reclaim and transfer to hopper.

We conservatively used U.S. EPA’s AP-42 emission factors for vehicle movement on unpaved roads in 13.2.2, for estimating particulate matter emissions from the FELs movement in the storage areas.

5.25.1 PM/PM10/PM2.5 BACT Baseline
There are no state, local or federal regulations applicable to PM/PM10/PM2.5 emissions from FEL movement on unpaved surfaces at the HBI Facility. Therefore, there is no “BACT baseline” for this operation.
5.25.2 Step 1 – Identify Available PM/PM10/PM2.5 Control Options

A summary of the precedents from U.S. EPA’s RBLC database and other known permit precedents for the vehicle transport on unpaved surfaces is presented in Table 5-23.

Table 5-23. Summary of PM/PM10/PM2.5 BACT Precedence for Unpaved Roads

<table>
<thead>
<tr>
<th>RBLC ID/ State</th>
<th>Facility Name</th>
<th>Permit Date</th>
<th>Process Description</th>
<th>Control</th>
<th>Emission Limit</th>
</tr>
</thead>
<tbody>
<tr>
<td>OK-0173</td>
<td>CMC Steel Oklahoma</td>
<td>1/19/2016</td>
<td>Unpaved roads</td>
<td>Watering and chemical stabilization (from permit)</td>
<td>NA</td>
</tr>
<tr>
<td>MD-0046</td>
<td>Keys Energy Center</td>
<td>10/31/2014</td>
<td>Unpaved roads</td>
<td>Watering</td>
<td>NA</td>
</tr>
<tr>
<td>MD-0042</td>
<td>Wildcat Point Generating Facility</td>
<td>4/8/2014</td>
<td>Unpaved roads</td>
<td>Reasonable precautions</td>
<td>NA</td>
</tr>
<tr>
<td>OH-0344</td>
<td>V&amp;M Star</td>
<td>1/27/2011</td>
<td>Unpaved roads</td>
<td>Watering or chemical stabilization or suppressants at sufficient frequencies</td>
<td>PM - 38.3 tons/year PM10 – 7.7 tons/year</td>
</tr>
<tr>
<td>LA-0239</td>
<td>Consolidated Environmental Mgmt.</td>
<td>05/24/2010</td>
<td>Unpaved roads</td>
<td>Watering or chemical suppression</td>
<td>PM - 18.69 lb/hour</td>
</tr>
</tbody>
</table>

The proposed FEL’s movement for reclaim and transfer of various materials result in release of small amount of fugitive particulate matter emissions from lifting of silt by the vehicle tires/tracks. The potential control options for controlling emissions from these operations are identified below:

(a) Paving of unpaved roads
(b) Watering and/or chemical stabilization

5.25.3 Step 2 – Eliminate Technically Infeasible PM/PM10/PM2.5 Controls

Paving of the surfaces within the stockpiles area is not technically feasible because use of heavy FELs for the various reclaim activities will damage the paved surfaces. Watering and/or chemical stabilization is technically feasible for controlling PM/PM10/PM2.5 emissions from the movement of FELs in unpaved areas.

5.25.4 Step 3 – Rank PM/PM10/PM2.5 Control Options

No ranking is necessary as only the watering and/or chemical stabilization is technically feasible option for these operations.

5.25.5 Step 4 – Evaluate Feasible PM/PM10/PM2.5 Control Options

As shown in Appendix C, the FELs movement on unpaved surfaces will use watering and/or chemical stabilization to control particulate matter emissions (weather permitting). Use of the top control technology will not have any material adverse energy, environmental or economic impacts. Therefore, it is appropriate that use of watering and/or chemical stabilization form the basis for establishing the PM/PM10/PM2.5 BACT for the fugitive emissions from the FELs.
5.25.6  Step 5 – Establish PM/PM10/PM2.5 BACT

Equipment design or work practice requirements are acceptable under the definition of BACT when technological or economic limitations on the application of measurement methodology would make the imposition of an emissions standard infeasible. That criterion is met with respect to fugitive particulate matter emissions from the FELs material reclaim and transfer operations. The use of watering and/or chemical stabilization represents the top ranked control option for these operations constitute BACT for fugitive PM/PM10/PM2.5.

5.26 Trucks Movement on Paved Roads PM/PM10/PM2.5 BACT Analysis

This section presents the required PM/PM10/PM2.5 BACT analysis for the fugitive particulate matter emissions from the trucks travel for various materials transport activities. The trucks will travel on paved roads to various material stockpile areas. The truck transport activities on paved roads include the following:

(a) Lumps transport.
(b) Fines transport.
(c) Cement coating transport.
(d) HBI transport.

We used U.S. EPA’s AP-42 emission factors for vehicle movement on paved roads in 13.2.1, for estimating particulate matter emissions from the truck travel on the paved roads.

5.26.1 PM/PM10/PM2.5 BACT Baseline

There are no state, local or federal regulations applicable to PM/PM10/PM2.5 emissions from truck travel on paved roads at the HBI operations. Therefore, there is no “BACT baseline” for this operation.

5.26.2 Step 1 – Identify Available PM/PM10/PM2.5 Control Options

A summary of the precedents from U.S. EPA’s RBLC database and other known permit precedents for the trucks’ use on paved roads is presented in Table 5-24.

The proposed trucks’ travel for transport of various materials result in release of small amount of fugitive particulate matter emissions from resuspension of loose material on the road surfaces. The potential control option for controlling emissions from these operations is use of water flushing and sweeping (weather permitting).

5.26.3 Step 2 – Eliminate Technically Infeasible PM/PM10/PM2.5 Controls

Water flushing and sweeping is technically feasible for controlling fugitive PM/PM10/PM2.5 emissions from the truck travel activities on paved roads.
Table 5-24. Summary of PM/PM10/PM2.5 BACT Precedence for Paved Roads

<table>
<thead>
<tr>
<th>RBLC ID/State</th>
<th>Facility Name</th>
<th>Permit Date</th>
<th>Process Description</th>
<th>Control</th>
<th>Emission Limit</th>
</tr>
</thead>
<tbody>
<tr>
<td>IN-0263</td>
<td>Midwest Fertilizer Company</td>
<td>3/23/2017</td>
<td>Paved roads</td>
<td>Wet suppression and prompt cleanup</td>
<td>NA</td>
</tr>
<tr>
<td>MD-0046</td>
<td>Keys Energy Center</td>
<td>10/31/2014</td>
<td>Paved roads</td>
<td>Sweeping</td>
<td>NA</td>
</tr>
<tr>
<td>MD-0042</td>
<td>Wildcat Point Generating Facility</td>
<td>4/8/2014</td>
<td>Paved roads</td>
<td>Reasonable precautions</td>
<td>NA</td>
</tr>
<tr>
<td>IN-0179</td>
<td>Ohio Valley Resources LLC</td>
<td>9/25/2013</td>
<td>Paved roads</td>
<td>Sweeping and wet suppression</td>
<td>90% control efficiency</td>
</tr>
<tr>
<td>IN-0166</td>
<td>Indiana Gasification</td>
<td>6/27/2012</td>
<td>Paved roads</td>
<td>Sweeping and wet suppression</td>
<td>90% control efficiency</td>
</tr>
<tr>
<td>OH-345</td>
<td>DP&amp;L JM Stuart Generating Station</td>
<td>8/16/2011</td>
<td>Paved roads</td>
<td>Watering and reduced speed</td>
<td>110.96 tons/year</td>
</tr>
<tr>
<td>OH-0344</td>
<td>V&amp;M Star</td>
<td>1/27/2011</td>
<td>Paved roads</td>
<td>Watering or chemical stabilization or suppressants at sufficient frequencies</td>
<td>PM - 38.3 tons/year, PM10 – 7.7 tons/year</td>
</tr>
</tbody>
</table>

5.26.4 Step 3 – Rank PM/PM10/PM2.5 Control Options
No ranking is necessary as only the water flushing and sweeping is technically feasible option for these operations.

5.26.5 Step 4 – Evaluate Feasible PM/PM10/PM2.5 Control Options
As shown in Appendix C, the truck travel on paved roads will use water flushing and sweeping to control fugitive particulate matter emissions. Use of the top control technology will not have any material adverse energy, environmental or economic impacts. Therefore, it is appropriate that use of water flushing and sweeping form the basis for establishing the fugitive PM/PM10/PM2.5 BACT for the proposed truck travel activities.

5.26.6 Step 5 – Establish PM/PM10/PM2.5 BACT
Equipment design or work practice requirements are acceptable under the definition of BACT when technological or economic limitations on the application of measurement methodology would make the imposition of an emissions standard infeasible. That criterion is met with respect to particulate matter emissions from the truck material transport operations. Use of water flushing and sweeping represents the top ranked control option for these operations constitute BACT for fugitive PM/PM10/PM2.5.
6. Ambient Air Quality Impacts Analysis

This section presents a summary of the PSD required ambient air quality impacts analysis. The full modeling report, including detailed information regarding model selection, receptor location, and modeling procedures, are included as Appendix E. As described in subsection 4.1.2.4, the proposed Project will be ‘significant’ for PM, PM10, PM2.5, NOx, CO, and GHGs. Based on historical precedence, and U.S. EPA’s guidance, impacts analysis is not required for PM and GHGs. This section addresses impacts of other pollutants for which the area is attainment or unclassifiable.

6.1 Emissions Rates for Modeling Purposes

The emissions rates used for modeling purposes represent the worst case short term and long term rates for each of the proposed units. These rates are presented in section 3, Appendix C, and Appendix E of this application. As previously noted, consistent with OEPA guidance, emissions from the proposed intermittent operations (emergency engines and flaring during process upset/startup/shutdown) are not included for demonstrating compliance with short term national ambient air quality standards (NAAQS). In addition, for HBI rail loading that occurs over one shift, the emission rate was averaged for 24-hours for demonstrating compliance with the 24-hour PM10 and PM2.5 NAAQS.

6.2 Summary of Class II Modeled Impacts

This section presents the modeling results for the propose HBI Facility for Class II areas.

6.2.1 Class II Significant Impacts Analysis

Emissions from the proposed project are modeled in accordance with the modeling protocol submitted in August 2017 and the follow-up discussions and submittals. The resulting ambient impacts are compared with the Class II significant impact levels (“SILs”) codified at OAC 3745-31-23 and issued by the U.S. EPA in 40 CFR § 51.165(b)(2) or by guidance. In accordance with the OEPA and U.S. EPA’s procedures, if the maximum ambient impacts from the project are below the particular SIL, the project is presumed to neither cause nor contribute to a violation of the NAAQS or PSD increment for that pollutant. Pollutants with impacts that exceed the SIL, will be included in both the NAAQS and increment analyses. Table 6-1 presents the Class II significant impacts analyses for the proposed Project.

78 In a March 2011 permitting guidance issued by the U.S.EPA, it observed that “[s]ince there are no NAAQS or PSD increments for GHGs, the requirements .. to demonstrate that a source does not cause or contribute to a violation of the NAAQS is not applicable to GHGs. Thus, we do not recommend that PSD applicants be required to model or conduct ambient monitoring for CO2 or GHGs.” [footnotes omitted] PSD and Title V Permitting Guidance for Greenhouse Gases, EPA-457/B-11-001, March 2011, at pages 47-48.
Table 6-1. Class II Significant Impact Analysis Result

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Average</th>
<th>Model Conc. (µg/m³)</th>
<th>SIL (µg/m³)</th>
<th>% SIL</th>
</tr>
</thead>
<tbody>
<tr>
<td>NO₂</td>
<td>1-HR</td>
<td>9.9</td>
<td>7.5</td>
<td>132%</td>
</tr>
<tr>
<td></td>
<td>ANNUAL</td>
<td>0.89</td>
<td>1.0</td>
<td>89%</td>
</tr>
<tr>
<td>CO</td>
<td>1-HR</td>
<td>335</td>
<td>2000</td>
<td>17%</td>
</tr>
<tr>
<td></td>
<td>8-HR</td>
<td>128</td>
<td>500</td>
<td>26%</td>
</tr>
<tr>
<td>PM10</td>
<td>24-HR</td>
<td>21.13</td>
<td>5.0</td>
<td>423%</td>
</tr>
<tr>
<td></td>
<td>ANNUAL</td>
<td>2.59</td>
<td>1.0</td>
<td>259%</td>
</tr>
<tr>
<td>PM2.5</td>
<td>24-HR</td>
<td>6.29</td>
<td>1.2</td>
<td>524%</td>
</tr>
<tr>
<td></td>
<td>ANNUAL</td>
<td>1.09</td>
<td>0.3</td>
<td>365%</td>
</tr>
</tbody>
</table>

For the proposed Project, predicted impacts exceed the applicable SIL for NO₂ 1-hour NAAQS and PM10 and PM2.5 NAAQS for all averaging periods. Therefore, these criteria pollutants were further analyzed for cumulative modeling that includes nearby sources. For all other pollutant-averaging time combinations, the project impacts are below the SIL.

6.2.2 Summary of NAAQS Analysis

The NAAQS analyses results are presented below. The modeling analyses were performed using AERMOD. Table 6-2 presents the NAAQS analyses for the proposed Project that exceed the SIL.

Table 6-2. NAAQS Analysis Result

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Average</th>
<th>Model Conc. (µg/m³)</th>
<th>Background (µg/m³)</th>
<th>Total (µg/m³)</th>
<th>NAAQS (µg/m³)</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>NO₂</td>
<td>1-HR</td>
<td>133.98</td>
<td>75.6</td>
<td>209.6</td>
<td>188</td>
<td>Project impact insignificant as paired in time and space.</td>
</tr>
<tr>
<td>PM2.5</td>
<td>24-HR</td>
<td>47.3</td>
<td>22.6</td>
<td>69.9</td>
<td>35</td>
<td>Project impact insignificant as paired in time and space.</td>
</tr>
<tr>
<td></td>
<td>ANNUAL</td>
<td>3.05</td>
<td>8.64</td>
<td>11.7</td>
<td>12</td>
<td>Below NAAQS</td>
</tr>
<tr>
<td>PM10</td>
<td>24-HR</td>
<td>122.46</td>
<td>22</td>
<td>145.5</td>
<td>150</td>
<td>Below NAAQS</td>
</tr>
</tbody>
</table>

The Project impacts for PM2.5 annual standard and PM10 are below the applicable NAAQS. The modeled 1-hour NO₂ and PM2.5 24-hour standard impacts exceed the NAAQS. However, as explained in Appendix E, the modeled 1-hour NO₂ and 24-hour PM2.5 exceedances are attributable to existing offsite sources that were modeled as part of the off-site inventory and not caused by the proposed HBI Facility. The maximum Project impacts at any of the receptor with existing
exceedance are well below the SIL for that criteria pollutant. Therefore, the Project will not cause or contribute to the violation of the 1-hour NO2 NAAQS or the 24-hour PM2.5 NAAQS.

### 6.2.3 Class II PSD Increment Analysis

PM10 and PM2.5 increment analyses were conducted for the proposed Project. Table 6-3 presents the increment analyses for the proposed Project. The increment analysis addressed the requirement both for overall impacts to be below the applicable increment and project impacts to be below the 83% of increment for the projects located at brownfield sites.

#### Table 6-3. Increment Analysis Result

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Average</th>
<th>Case</th>
<th>Model Conc. (µg/m³)</th>
<th>Standard (µg/m³)</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM2.5</td>
<td>24-HR</td>
<td>All Sources</td>
<td>6.95</td>
<td>9.0</td>
<td>Cumulative impacts</td>
</tr>
<tr>
<td></td>
<td></td>
<td>HBI Only</td>
<td>6.27</td>
<td>7.5</td>
<td>Project &lt;83% of Increment</td>
</tr>
<tr>
<td></td>
<td>Annual</td>
<td>All Sources</td>
<td>1.29</td>
<td>4.0</td>
<td>Cumulative impacts</td>
</tr>
<tr>
<td></td>
<td></td>
<td>HBI Only</td>
<td>1.15</td>
<td>2.0</td>
<td>Project &lt;50% of Increment.*</td>
</tr>
<tr>
<td>PM10</td>
<td>24-HR</td>
<td>All Sources</td>
<td>27.0</td>
<td>30.0</td>
<td>Cumulative impacts</td>
</tr>
<tr>
<td></td>
<td></td>
<td>HBI Only</td>
<td>17.7</td>
<td>24.9</td>
<td>Project &lt;83% of Increment</td>
</tr>
<tr>
<td></td>
<td>Annual</td>
<td>All Sources</td>
<td>4.7</td>
<td>17.0</td>
<td>Cumulative impacts</td>
</tr>
<tr>
<td></td>
<td></td>
<td>HBI Only</td>
<td>2.6</td>
<td>8.5</td>
<td>Project &lt;50% of Increment.*</td>
</tr>
</tbody>
</table>

*For the cases where project impacts are below the 50% of increment, per OEPA Engineering Guide 69 additional comparison with 83% of the increment is not necessary.

The increment analysis shows that modeled concentration for the Project are below the applicable Class II increment thresholds.

### 6.2.4 Visibility Analysis in Class II Areas

A visibility analysis for the proposed Project impacts on the Class II areas is conducted using the VISCREEN model. Results of this analysis are presented in Appendix E. This analysis indicates that the Project impacts will not exceed the visibility screening criteria. The Project therefore will not adversely affect visibility at the Cuyahoga Valley National Park.
7. Site Air Quality Analysis

Per OAC 3745-31-14, an applicant for a PSD permit is required to collect pre-construction ambient air quality data for each pollutant for which the project PTE is significant. OAC 3745-31-13(H) provides exemptions from pre-application monitoring requirements for the Project. Based on the EPA guidance, if sufficient data exists to provide representative regional background concentrations, agency may waive the preconstruction monitoring requirement. IU has provided this demonstration in the modeling protocol submitted on August 4, 2017 and requested a waiver from the preconstruction monitoring requirements for the proposed Project per OAC 3745-31-13(H)(4). Available data from the existing monitors in the area is provided in Appendix E.

8. Additional Impacts Analyses

An additional impacts analysis is performed consistent with the requirements of OAC 3745-31-17 (Attainment Provisions – Additional Impacts Analysis) to determine potential air emissions impacts on soils, vegetation, visibility, and growth. The project will emit PM, PM10, PM2.5, NOx, and CO in excess of the PSD significant emission rates and are therefore considered in the analysis. Per the U.S. EPA’s guidance the additional impacts analyses requirements do not apply to the emissions of GHGs from the project. \(^8^0\) \(^8^1\)

8.1 Effects on Soil

The pollutants included in this analysis of the potential impairment to soils are PM10, PM2.5 CO, and NOx. The results of the soils impact analysis show that no significant impairment will occur as a result of the construction or operation of the proposed Project. Specific findings are documented in the following subsections.

8.1.1 Soil Survey

Over 88,000 acres (138 square miles) surrounding the site of the proposed Project were evaluated for the soils analysis using the U.S. Department of Agriculture Natural Resource Conservation Service Web Soil Survey application. The area evaluated encompasses portions of Lucas, Ottawa, and Wood Counties in Ohio and Monroe County in Michigan. \(^8^2\) As presented in Table 8-1, the primary soil type in this area is some variety of silty clay loam at over 28 percent of the total acreage in the study. Other types of soil in significant quantities around the facility include Udorthents loam, Colwood loam and combinations of urban land and Dixboro, Bixler, Del-Ray, Sisson, and Colwood loam. The pH of these soils ranged from 6.5 to 7.3.

The U.S. Department of Agriculture (USDA) considers approximately 33 percent of this land to be prime farmland if irrigated. No portion of the study area was identified as farmland of unique importance. Further, the USDA soil survey rated all of the soil types listed in Table 8-1 as having somewhat or very limited use for recreational activities such as camping, paths and trails, picnic areas, and playgrounds, with the exception of the following for which no rating was provided: udorthents, urban land, Lenawee-urban land complex, Sisson-urban land complex, and Ottokie-urban land complex. Less than 5 percent of the total study area is identified as having unlimited recreational value, specifically for use as golf fairways.

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\(^8^1\) In a March 2011 permitting guidance, the U.S.EPA observed that “…it is not necessary for applicants or permitting authorities to assess impacts from GHGs in the context of the additional impacts analysis or Class I area provisions of the PSD regulations… EPA believes that the most practical way to address the considerations reflected in the Class I area and additional impacts analysis is to focus on reducing GHG emissions to the maximum extent.” PSD and Title V Permitting Guidance for Greenhouse Gases, EPA-457/B-11-001, March 2011, at pages 47-48.

Table 8-1. Major Soil Types in Study Area

<table>
<thead>
<tr>
<th>Map Unit Name</th>
<th>Acres</th>
<th>Percent of Total</th>
<th>pH</th>
</tr>
</thead>
<tbody>
<tr>
<td>Latty silty clay, till substratum, 0 to 1 percent slopes</td>
<td>18,084.9</td>
<td>23.4</td>
<td>7.2</td>
</tr>
<tr>
<td>Udorthents, loamy</td>
<td>7,982.3</td>
<td>10.3</td>
<td>-</td>
</tr>
<tr>
<td>Urban land</td>
<td>5,384.8</td>
<td>7.0</td>
<td>-</td>
</tr>
<tr>
<td>Dixboro-Urban land complex, 0 to 2 percent slopes</td>
<td>4,814.2</td>
<td>6.2</td>
<td>6.7</td>
</tr>
<tr>
<td>Bixler-Urban land complex, 0 to 3 percent slopes</td>
<td>3,310</td>
<td>4.3</td>
<td>6.5</td>
</tr>
<tr>
<td>Del-Ray-Urban land complex, 0 to 3 percent slopes</td>
<td>3,043</td>
<td>3.9</td>
<td>7.3</td>
</tr>
<tr>
<td>Toledo silty clay, 0 to 1 percent slopes</td>
<td>2,987.6</td>
<td>3.9</td>
<td>6.9</td>
</tr>
<tr>
<td>Fulton silty clay loam, 0 to 2 percent slopes</td>
<td>2,546.8</td>
<td>3.3</td>
<td>6.7</td>
</tr>
<tr>
<td>Lenawee silty clay loam, 0 to 1 percent slopes</td>
<td>1849.9</td>
<td>2.4</td>
<td>7.2</td>
</tr>
<tr>
<td>Sisson-Urban land complex, 2 to 12 percent slopes</td>
<td>1,325.6</td>
<td>1.7</td>
<td>7</td>
</tr>
<tr>
<td>Colwood-Urban land complex</td>
<td>1,297.3</td>
<td>1.4</td>
<td>7.3</td>
</tr>
<tr>
<td>Colwood loam</td>
<td>1,111.1</td>
<td>1.4</td>
<td>7.3</td>
</tr>
</tbody>
</table>

8.1.2 Pollutant Impacts on Soils

Current literature contains little information on impairment or other direct effects on soils due to air pollution, and we did not identify as part of this analysis any studies in which potential pollutant effects on the soils specific to the project area were evaluated. This is consistent with U.S. EPA’s findings on this topic:

In contrast to the amount of published information on the effects of atmospheric pollutants on plants and animals, very little has been reported on their effects on soils. Research on trace elements in soils, often the same elements as atmospheric pollutants, has been directed to notable deficiencies or excesses that limit agricultural crop production. When the amount of an atmospheric pollutant entering a soil system is sufficiently small, the natural ecosystem can adapt to these small changes in much the same way as the ecosystem adapts to the natural weathering processes that occur in all soils. Cultural practices (e.g., liming, fertilization, use of insecticides and herbicides) add elements and modify a soil system more than a small amount of deposited atmospheric pollutant can. The secondary effects of the pollutant appear to impact the soil system more adversely than the addition of the pollutant itself to the soil. For instance, damaging or killing vegetative cover could lead to increased solar radiation, increased soil temperatures, and moisture stress. Increased runoff and erosion add to the problem. The indirect action of the pollutant, through changes to the stability of the system, thus may be more significant than the direct effects on soil invertebrates and soil microorganisms. However the lack of long-term historical data on both the type and amount of atmospheric pollutants as well as the lack of baseline data on soils has made difficult the task of determining the effect of pollutants on soils by monitoring changes associated with exposure to pollutants. A limited number of studies have been carried out on trace element contamination in soils. Plant and animal communities appear to be affected before noticeable accumulations occur in the soils. Thus, the approach used here in which the soil acts as an intermediary in the
transfer of deposited trace elements to plants appears reasonable as a first attempt at identifying the air quality related values associated with soils.\(^8^3\)

Because deposition of NOx and other nitrogen compounds into soils in the survey area could occur as a result of emissions from the construction and operation of the proposed Project, it is reasonable to consider whether some marginal acidification of the soils might occur as a result of this project. As presented in Table 8-1, the majority of the major soil types in the survey area are alkaline (i.e., pH greater than 7.0), meaning that some degree of acidification can be readily tolerated and may in fact be desirable. Based on these facts, we have concluded that the proposed facility will not have an adverse impact on soils.

### 8.2 Effects on Vegetation

This analysis of impacts to vegetation covers the entirety of the Lucas, Ottawa, and Wood Counties in Ohio and Monroe County in Michigan. This study area exceeds the scope suggested by U.S. EPA guidance, which is limited to the area within the impact area of the proposed facility (10km).\(^8^4\)

#### 8.2.1 Vegetation Survey

The natural vegetation located in these counties is primarily deciduous forest consisting of oak, hickory, ash, and maple varieties.\(^8^5\)\(^8^6\) According to a 2010 Ohio forest resource assessment conducted by the Ohio Department of Natural Resources Division of Forestry\(^8^7\), approximately 12% of Lucas County is forested. The forested areas of Ottawa and Wood Counties is approximately 8%. The forested acreage in Monroe County, Michigan is approximately 10% of the total county area.\(^8^8\)

Information provided in the 2012 USDA Census reports for Michigan and Ohio was used to identify commercial vegetation in the study area.\(^8^9\)\(^9^0\) The major crops are presented in Table 8-2. As shown, approximately 50 percent of the land included in the study area is used for harvested crops. Of this total, 94 percent is used for soybeans, corn for grain, and wheat for grain. Other crops each harvested from less than 1 percent of the harvested area include forage, oats for grain, and vegetables. Specific locations for the farms for these harvested crops is not provided in the Census reports. Visual

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\(^8^4\) See, e.g., *Prevention of Significant Deterioration Workshop Manual* (EPA-450/2-80-081), Oct. 1980, at page I-D-6, expressly limiting the soils and vegetation impairment analysis to the “impact area”. See also the same document at page I-C-12, defining the impact area as a “circular area whose radius is equal to the greatest distance from the source to which approved dispersion modeling shows the proposed emissions will have a significant impact.”

\(^8^5\) Resource Bulletin NRS-36 Ohio Forests 2009

\(^8^6\) Forest & Forestry Profile for Michigan Senate District 17, Bill Cook, MSU Extension, January 2006

\(^8^7\) Ohio’s Statewide Forest Resource Assessment, Ohio Department of Natural Resources, Division of Forestry, June 2010.

\(^8^8\) Forest & Forestry Profile for Michigan Senate District 17, Bill Cook, MSU Extension, January 2006

\(^8^9\) 2012 Census of Agriculture, Michigan State and County Data, Volume 1, Issued May 2014.

\(^9^0\) 2012 Census of Agriculture, Ohio State and County Data, Volume 1, Issued May 2014.
inspection of aerial photographs of the area suggests the majority of the harvested areas are located beyond 10km radius of the HBI Facility.

8.2.2 Identification of Pollutants of Concern

As discussed below, there are substantial scientific data characterizing the effects of air pollution on certain crops (e.g., common wheat), whereas there are limited data available for other crops. Air pollutants can affect crops through two principal means:

- Direct phytotoxic effects from air concentrations of pollutants; and,
- Indirect phytotoxic effects due to deposition of pollutants in soils in which the crops are growing.

Table 8-2. Land Use for Commercially Significant Vegetation in Study Area¹²

<table>
<thead>
<tr>
<th>Vegetation</th>
<th>Lucas</th>
<th>Ottawa</th>
<th>Wood</th>
<th>Monroe</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Corn (grain)</td>
<td>21,940</td>
<td>25,964</td>
<td>87,393</td>
<td>76,225</td>
<td>211,522</td>
</tr>
<tr>
<td>Forage</td>
<td>468</td>
<td>3,885</td>
<td>4,494</td>
<td>3,827</td>
<td>12,674</td>
</tr>
<tr>
<td>Oats (grain)</td>
<td>-</td>
<td>396</td>
<td>373</td>
<td>208</td>
<td>977</td>
</tr>
<tr>
<td>Soybeans</td>
<td>30,690</td>
<td>60,815</td>
<td>122,804</td>
<td>82,227</td>
<td>296,536</td>
</tr>
<tr>
<td>Vegetables</td>
<td>1,286</td>
<td>1,699</td>
<td>1,285</td>
<td>8,459</td>
<td>12,729</td>
</tr>
<tr>
<td>Wheat (grain)</td>
<td>3,663</td>
<td>3,782</td>
<td>21,739</td>
<td>16,897</td>
<td>46,081</td>
</tr>
<tr>
<td>Total Harvested Area</td>
<td>58,387</td>
<td>97,054</td>
<td>242,238</td>
<td>189,032</td>
<td>586,711</td>
</tr>
<tr>
<td>Total Land Area of Study</td>
<td>217,894</td>
<td>163,168</td>
<td>395,085</td>
<td>435,200</td>
<td>1,211,347</td>
</tr>
</tbody>
</table>

¹2012 Census of Agriculture, Michigan State and County Data, Volume 1, Issued May 2014. Data presented as harvested acres. Crops with greater than 200 acres harvested considered for this analysis.
²2012 Census of Agriculture, Ohio State and County Data, Volume 1, Issued May 2014. Data presented as harvested acres. Crops with greater than 200 acres harvested considered for this analysis.

8.2.2.1 Direct Phytotoxic Effects

Of the gaseous air pollutants covered by this analysis, only NOx (i.e., NO and NO₂) is known to be toxic to some plants at moderate to high concentrations in the ambient air. Carbon monoxide is not considered phytotoxic, thus it was not considered further by this analysis.⁹¹ Studies linking gaseous

species of nitrogen to plant foliar damage have been conducted well above concentration levels occurring in the United States. Thus, there is little evidence to show that current U.S. concentrations of gaseous phase nitrogen cause phytotoxic effects.\textsuperscript{92} In the 2008 review of the secondary NO\textsubscript{2} NAAQS, EPA concluded that agricultural ecosystems are not sensitive to nitrogen concentrations found in the U.S.\textsuperscript{93}

8.2.2.2 Indirect Effects

The particulate matter emissions from the proposed Project may contain trace quantities of chromium, copper, fluoride, lead, manganese, nickel, and zinc which have been found to adversely affect plants.\textsuperscript{94} However, because the Project will emit these contaminants at such low levels, it is unlikely that these emissions will significantly impact vegetation adjacent to the facility.

8.2.3 Determination of Effects Concentrations

8.2.3.1 Direct Phytotoxic Effects

As is customary for this type of analysis, the assessment relied heavily on the screening criteria in the U.S. EPA report, \textit{A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals}.\textsuperscript{95} This document establishes the air pollutant concentrations that are generally viewed by U.S. EPA to be protective of soils and vegetation having significant commercial or recreational value, including agricultural crops, based on a broad review of pertinent scientific literature. We also relied on the secondary National Ambient Air Quality Standards (NAAQS),\textsuperscript{96} which are established by U.S. EPA at levels that are protective of the public welfare, including agriculture.

8.2.3.2 Indirect Deposition Effects

Two general approaches have been used in establishing deposition rate limits and soil concentration limits: a) preventing accumulation of pollutants in soils; and b) maximizing the capacity of soils to assimilate, attenuate, and detoxify pollutants. The first approach is based on the premise that soil can be used without any undue restriction if it is maintained free of contamination; if pollutants are artificially introduced and are allowed to accumulate in the soil, then, over the long term, the potential uses of the soil may become limited. The second approach is based on the premise that soils have a capacity to detoxify pollutants. This approach has been applied by the U.S. EPA and by the World Health Organization.\textsuperscript{97}

\textsuperscript{93} Ibid
\textsuperscript{95} Ibid
\textsuperscript{96} See, 40 CFR part 50.
8.2.4 Results

This section presents the results of dispersion modeling (and deposition calculations, where applicable) for each air pollutant, and assesses these results with respect to effects levels.

**PM10/PM2.5 Effects:** As shown in section 6, the Project particulate matter impacts for PM10 and PM2.5 are below the secondary standards both for 24-hour and annual NAAQS. Therefore, particulate matter emissions from the Project will not adversely affect the vegetation in the area.

**NOx Effects:** NO\textsubscript{x} includes both nitric oxide (NO) and nitrogen dioxide (NO\textsubscript{2}), and much of the scientific literature treats these two gases separately. Based on the results of the air quality impacts analysis, the maximum predicted ambient NO\textsubscript{x} concentrations due to emissions from the proposed Project are 8.89 μg/m\textsuperscript{3} (1-hour average) and 0.86 μg/m\textsuperscript{3} (annual average). These values represent total NO\textsubscript{x}, including both NO and NO\textsubscript{2}. These impacts are several orders of magnitude below the secondary NAAQS of 100 μg/ m\textsuperscript{3} (annual average)\textsuperscript{98} and the minimum U.S. EPA screening values of 3,760 μg/ m\textsuperscript{3} (4-hr average) and 94 μg/ m\textsuperscript{3} (annual average).\textsuperscript{99} Both the secondary NAAQS and the screening value are expressed in terms of NO\textsubscript{2}; there are no NAAQS or screening values for NO.\textsuperscript{100}

The agricultural crops for which the minimum U.S. EPA screening value is listed as being protective include all of the primary crops identified above (i.e., beans, corn, and wheat).\textsuperscript{101} The literature was reviewed to ascertain whether there exists, in the scientific literature, any basis for concluding that: a) the secondary NAAQS and the minimum U.S. EPA screening value are not protective of any of the crops identified herein; or b) the Project’s NO\textsubscript{x} emissions will have an unacceptable, adverse impact on agricultural crops in the study area. A summary of our findings follows.

In April 2012, U.S. EPA issued a final rule retaining and affirming the secondary NO\textsubscript{2} NAAQS of 100 μg/ m\textsuperscript{3} (annual average).\textsuperscript{102} This action reflected both the U.S. EPA Administrator’s finding that this standard is “adequate to protect against direct phytotoxic effects on vegetation”\textsuperscript{103} and her judgment that an alternative standard to protect against deposition-related effects is not supported by currently available data.\textsuperscript{104} The data relied upon by U.S. EPA with respect to direct phytotoxic effects are summarized in the *Integrated Science Assessment*,\textsuperscript{105} including the following observation:

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\textsuperscript{98} 40 CFR § 50.11(c).
\textsuperscript{100} Ibid.
\textsuperscript{101} Ibid at p. 68.
\textsuperscript{103} Ibid at p. 20241.
\textsuperscript{104} Ibid at pp. 20262-63.
An analysis of over 50 peer-reviewed reports on the effects of NO\textsubscript{2} on foliar injury indicated that plants are relatively resistant to NO\textsubscript{2}. With few exceptions, visible injury was not reported at concentrations below 377 μg/ m\textsuperscript{3}, and these occurred when the cumulative duration of exposures extended to 100 hours or longer.

In 2000, the WHO instituted a NO\textsubscript{X} guideline concentration value of 30 μg/m\textsuperscript{3} on an annual average (including both NO and NO\textsubscript{2}, expressed as NO\textsubscript{2}). The WHO declined to institute a short-term value, saying “[t]here are insufficient data to provide these levels with confidence at present,” but indicated that current evidence would suggest a guideline NO\textsubscript{X} concentration value of about 75 μg/m\textsuperscript{3} on a daily average. The guideline concentration value is intended to be protective of all classes of vegetation under all environmental conditions.\textsuperscript{106}

In summary, nothing in the scientific literature reviewed indicates that the secondary NAAQS and the minimum annual U.S. EPA screening value are not protective of any of the crops identified herein. The maximum predicted NO\textsubscript{X} concentration is well below the secondary NAAQS, the minimum U.S. EPA screening value, guideline concentration values established by foreign governmental agencies, and concentrations that are identified in the literature as being harmful to commercially significant vegetation in the study area.

### 8.3 Soil and Vegetation Analysis Conclusion

Based on the effects analysis described herein, we conclude that emissions from the proposed Project are not expected to result in adverse effects to soils, crops, or plant species of concern, within the vicinity of the project site. For each pollutant of concern, the predicted ambient concentration or the predicted deposition rate is well below the secondary NAAQS and the minimum screening values established by U.S. EPA. Nothing in the scientific literature identified during this review indicates that the secondary NAAQS and minimum U.S. EPA screening values are not protective of any identified crops, and the predicted ambient concentration and deposition rate are less than the screening values established by other governmental authorities.

### 8.4 Visibility

The class II visibility impacts are discussed in subsection 6.2.4 and Appendix E of the application.

### 8.5 Growth Impact Analysis

The purpose of the growth analysis is to quantify the associated industrial, commercial, and residential growth that will occur in the area due to the Project. The associated growth is the growth that occurs as a result of the construction or modification of the source, but which is not part of the source. The emissions that result from this growth are then estimated and the effects of these emissions on the surrounding environment are determined.

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The growth analysis addresses only permanent economic growth attributable to the proposed Project. Short-term or temporary impacts, such as construction, are not considered permanent growth and therefore are not addressed as an additional impact.

Given the large local population, the construction associated with the Project will not have a significant impact to the local population. Construction of the project is expected to result in 130 new, permanent positions at the site, and approximately 1,200 temporary construction positions over two years. It is anticipated that the construction workforce will be drawn, largely from the surrounding communities. Therefore, the effect on air quality from the incremental growth will be insignificant.
9. **Class I Area Impacts Analysis**

There are no Class I areas located within 300km of the proposed Project. Based on the Federal Land Manager (FLM) guidance, we calculated Q/d value of 1.4. See further explanation in Appendix E. The Q/d for the project is well below the FLM’s guidance threshold of 10. FLM for the area confirmed in correspondence with the consultant that the AQRV analysis is not required for the Project.\(^{107}\)

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Appendix A – PTI Application Forms
Appendix B – Site Layout and Process Flow Diagrams
Appendix C – Emissions Calculations
Appendix D – BACT Impact Analysis Tables
Appendix E – Air Quality Modeling Report