The Nucor Experience

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- Background on Nucor project
- Comments and Responses from EPA for Nucor GHG BACT

About St James Facility

- 2.5M TPY iron making facility will use direct reduction technology to convert natural gas and iron ore pellets into high quality direct reduced iron ("DRI")
- DRI used by Nucor's steel mills, along with recycled scrap, in producing numerous high quality steel products such as sheet, plate and special bar quality steel.
- The DRI facility is the first phase of a multi-phase plan that may include an additional DRI facility, coke plant, blast furnace, pellet plant and steel mill.
- Additional DRI plant will increase production to 5.0M TPY.
- $750M investment, 500 permanent jobs

Why DRI?

- DRI facility was chosen for the <u>first phase</u> of this project, in place of a blast furnace and coke making facility
- It offers a carbon footprint that is one-third of that for the coke oven/blast furnace route for the same volume of product but at less than half the capital cost.

Beginning the Permit Process

- Application for pig iron plant received in May 2008.
- Initially proposed for approval in October 2008 and a public hearing was held in November 2008.
- It was discovered that Nucor did not model certain "maintenance" emissions, so LDEQ agreed to require the necessary modeling and re-notice the permits.

The Long and Winding Road

- LDEQ again proposed for approval in August 2009. However, before the public hearing was conducted, EPA's Louisville Gas & Electric petition was finalized, and EPA informed LDEQ that $PM_{2.5}$ must be addressed.
- The hearing was canceled, and LDEQ required BACT and ambient air analyses for $PM_{2.5}$.

Are We There Yet?

- LDEQ again proposed for approval in March 2010, a public hearing was conducted in April 2010, and the permit was issued in May 2010.
- The original permit for pig iron did not address GHG. Tailoring Rule did not require PSD permits issued before 1-1-11 to address GHG.

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Just When Things Were Getting Back to Normal…

- An application to modify pig iron plant was submitted in August 2010. This application proposed to remove a number of sources and add NOx control equipment, as well as address the addition of the DRI.
- Original plan was to process before 1-1-11, but it became apparent early on that wasn't going to happen.
- GHG BACT analysis was submitted as additional info. Importantly, Nucor's submittal pre-dated EPA's BACT guidance, which was released in November 2010.

Whew!

- DRI was public noticed in November 2010, public hearing was held in December 2010, and the permit was issued in January 2011.
- All emissions except NH3 decreased substantially. NH3 increase due to SCR at pig iron plant.
- We believe it was the first PSD to address GHGs.
- Construction began March 7, 2011.

EPA Involvement

- EPA submitted comments on LDEQ's proposed BACT for GHGs. We were not surprised.
- Comments suggested EPA may not have fully understood the DRI process
- CO_2 is necessary in DRI process chemistry, so LDEQ selected an efficiency standard rather than a worst-case lb per hour limit as BACT.

Permit Specifics

- BACT was 13 million BTU per metric ton of DRI produced.
- The limit includes startup and shutdown emissions and any off-spec production.
- Slightly lower numbers have been published, but LDEQ could not find actual emissions data that suggested that the lower rates were achievable over the long term.

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Comment 1

LDEQ's draft PSD permit contains a proposed CO_2e BACT limit of "good combustion practices" for the Package Boiler and the Reformer/Main Flue Gas Stack based on an efficiency limit, as opposed to establishing a mass or CO_2e-based limit. Neither the draft permit for Nucor nor the administrative record provides a basis for why establishing a numerical BACT emissions limit is infeasible.

Response 1

The fuel is methane gas which has a CO2e of 21 compared to CO_2. It is therefore in the best interest to combust as much of the natural gas so that it can be converted to CO_2 and water.

Establishing a maximum limit for CO_2 makes no sense as poor combustion practices could lower CO_2 emissions by not combusting the methane which actually significantly increases CO_{2e} emissions. (Methane is 21 times worse)

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Response 1

Establishing a maximum limit for CO_2 makes no sense as better than expected combustion of the methane would generate higher CO_2 emissions but actually lower uncombusted methane creating a significantly lower CO_{2e} emission level.

Example, if calculated at 98% combustion efficiency, but actual efficiency was 99.5 %, a maximum limit for CO_2 would be exceeded, while overall CO_{2e} is lower.

Establishing a minimum limit for CO_2 makes no sense as overall product production levels (based upon consumer demand) could easily cause any such limit to be practically infeasible.

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Comment 2

- The draft PSD permit contains a proposed CO2e BACT limit of "acid gas separation system" for the Acid Gas Absorption Vent but contains no BACT analysis explaining how that control technology was selected.
- In addition, the permit does not contain a numerical GHG emission limit based on application of that control. As explained above, the permit must contain a numerical BACT limit or explain why establishing a numerical emissions limit for the pollutant under review is infeasible.
- LDEQ should include in the permit and/or the administrative record a basis for establishing an acid gas separation system as CO2e BACT, and provide a numerical BACT emissions limit (or explain why one is infeasible).

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Response 2

The Acid Gas Absorption control system was selected as BACT for removing Sulfur compounds from the reducing gas, not for controlling CO2e. Due to the nature of the amine solution being used to remove the sulfur compounds, CO_2 is also easily absorbed.

The CO_2 is contained within the spent reducing gas which is integral to the Reformer system. BACT for CO2e from that system was determined to be based upon the natural gas usage for the Reformer.

There is no independent BACT for CO2e from the Acid Gas Absorption vent as the CO_2 being released is generated within the DRI shaft when the oxygen is removed from the iron oxide ore.

Comment 3 and Response

The draft PSD permit does not provide baseline GHG emissions rates from the Direct Reduced Iron (DRI) plant in the administrative record for this permitting action. In this case, LDEQ has determined that the emissions from the DRI plant are above the thresholds for PSD permits, but the permit does not quantify such emissions in the administrative record for the permit application.

Baseline emissions for the DRI plant, using the definition of baseline emissions from LAC 33:III.509.B is 0 tons per year.

Comment 4

Baseline emissions are necessary in order to determine (1) major modification applicability for this new plant in the future, when there are changes to the existing design during the construction or operational phases of this plant, and (2) if the proposed conditions and restrictions which limit emissions from a new source achieve the "best available" control of those emissions. LDEQ should provide an estimate of baseline GHG emissions in the permit record or clearly indicate why at this time it is infeasible to provide such emissions.

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Response 4

- If there are changes during construction, the baseline emissions by definition still remain 0 tons per year. If there are future modifications to the facility outside of the 2 years allowed under the definition of new unit, the regulations clearly state that baseline emissions are to be based upon actual emissions.

  Actual emissions will not be available until the unit is operating for more than two years and is therefore irrelevant to this permitting action, and is only applicable to any hypothetical future modification.

Comment 5

The preliminary determination in the air permit evaluates BACT for CO_2 emissions; however, this information is missing from the BACT table in the permit. GHG BACT and these analyses have been provided by the applicant and, therefore, should be appropriately addressed in this table.

Further, LDEQ should explain in the record why BACT was not addressed for other GHG permitting pieces of equipment that are part of the DRI process.

Response 5

There are only two sources which create CO_2. They are the Reformer/DRI reactor system and the package boilers. All other sources that may contain CO_2 in an emission vent are only separate locations where the CO_2 that is created in the Reformer/DRI reactor are released.

When BACT was selected for the Reformer/DRI Reactor, it encompassed all known locations where the Reducing gas and combustion gas from the Reformer are released. As explained in the PSD permit, the BACT limit is for all CO_2 being generated by the DRI process. (Package Boilers excluded)

Comment and Response 6

LDEQ in the BACT analyses for GHG considers limits on the natural gas fuel usage as "no more than" 13 MMBtu per tonne of DRI produced. However, as noted above, the BACT limit established in the permit must be practically enforceable.

For determining the CO_2e emission limit, the production rates are being monitored in the Specific Requirements, but this should also be a federally enforceable limit. Please include the production rates in the permit as a federally enforceable condition.

The monitored production rate includes normal DRI production and all off-spec DRI produced by startups, shutdowns and upsets. As the facility has no direct control over the off-spec material that is being included in the monitored production, the requested production rate as a maximum federally enforceable limit will not be included.

Comment and Response 7

- Regarding the proposed efficiency limit for the DRI process, as of 2006 Midrex quoted efficiency levels in the range of 10.1 to 13.1 MMBTU/tonne. We encourage LDEQ to explore the latest DRI technologies and establish an efficiency limit that allows for the **maximum** degree of reduction of GHG emissions from the chosen process.
- The plant in the report was not designed to make as high-quality a product as is expected by the market today. High-quality DRI in 1993 would have been running at approximately 92% metallization and 1.5% carbon. Although this was top quality product at the time, Nucor has stated that they would not even consider purchasing that product today. The NSLA facility is designed to make DRI at 96% metallization and 3% carbon, which makes for a substantially different natural gas demand. Carbon content is essential in making high-quality steel products (you can't make carbon steel without carbon).

- Virtually all tests and literature discussing natural gas consumption from DRI units use optimal steady state operation as the basis for measurement. This excludes emissions from startup, shutdown, and process upsets that will necessarily occur. DRI units operate with startup and shutdown operations occurring quickly and frequently as part of normal operations, without the many safety hazards that may accompany the chemical and refining facilities that you may be familiar with as "steady state operations". The unit may startup and shutdown as frequently as twice a week in order to adjust for different ores, natural gas compositions, and product quality needs of specific orders, as opposed to the once or twice a year of many petrochemical sources (or less frequent). That is why the facility has been permitted with the alternate operating scenario represented by the hot flare to minimize releases of natural gas and unconverted reducing gas. Nucor has allowed approximately 10% for process operations to allow the facility to adjust to changing raw materials and product specifications. (Not all iron oxide ore will arrive with the same level of oxidation. Some ores will contain more than other ores.) Incidentally, this is the reason Nucor stressed and LDEQ concurred, that the 13 dT/metric ton limit should be inclusive of all material leaving the furnace, including off-spec and fines, which may be generated during startup and shutdown.

- The BACT limit accounts for the natural gas consumed by **all** combustion sources at the facility, including the reformers, package boilers, and hot flares, as well as the natural gas used as a reactant in the reducing furnace, inclusive of all startup/shutdown emissions and off-spec production. This BACT limit would be more appropriately attributed to the entire facility.

- Establishing BACT on a facility-wide basis is consistent with EPA's —PSD and Title V Permitting Guidance For Greenhouse Gases, which states that:

    - For new sources triggering PSD review, the CAA and **EPA rules provide discretion for permitting authorities to evaluate BACT on a facility-wide basis** by taking into account operations and equipment which affect the environmental performance of the overall facility. The term facility and source used in applicable provisions of the CAA and EPA rules encompass the entire facility and are not limited to individual emissions units.

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- Virtually all tests and literature discussing natural gas consumption from DRI units use net heating value (lower heating value, or LHV). Natural gas is sold, and will be tracked by NSLA, based on gross heating value (higher heating value or HHV). Just to be clear, the basic difference is that HHV accounts for all of the energy released during combustion (which assumes the flue gas has returned to ambient temperature), while LHV accounts for the fact that some of the energy is lost as unrecoverable heat in the flue gas. As a rule of thumb, LHV is approximately 10% less than HHV for this application. The limit proposed is based on HHV so that there is no confusion on the issue with regard to the metering of natural gas.

Comment 8

- BACT for the reformers has been evaluated without providing the control effectiveness of each control. In evaluating the effectiveness of the GHG emission controls, the amount of the pollutant emitted per product produced should be specified where feasible. LDEQ has only specified energy integration in MMBtu/tonne of DRI iron produced. As explained above, if a numerical emission limit (e.g., ton of Co2 per tonne of DRI produced) is infeasible, LDEQ should explain why it is infeasible to express the BACT limit as a numerical limit on the amount of GHG emissions.

Response 8

- As explained in the project description, the DRI process is chemically very simple. In order to remove the oxygen from the iron oxide ore, the DRI process generates CO_2 and water. Limiting the amount of CO_2 that can be created in the DRI reactor limits the ability of the facility from creating the desired metallization of the finished sponge iron. The actual metallization effect is not an exact process that generates a unique or consistent value. Only over a large time scale can the average metallization rate be evaluated. (Metallization refers to how much of the iron oxide ore has had the oxygen removed so that pure iron remains behind. As stated earlier, not all ores will have the same level of oxidation, thus requiring small operational changes to adjust for those differences.)

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Comment 9 and Response

- LDEQ should provide a rationale in the record why CO2 analyzers are not being used to determine emissions limits for the DRI plant. Additionally, the term "good combustion practices" is used for CO and GHG BACT control, but it does not have adequate monitoring for CO2 control, which is necessary in determining the compliance with the combustion standard.
- For the DRI Reformer, the stack is required to install a NO_X CEMS. The requirement will be modified to specify that when PS 2 offers the option of using a O_2 monitor or a CO_2 monitor, the facility will be required to use the CO_2 monitor as part of the NO_X CEMS. Thus CO_2 data will be measured and recorded.

Carbon Capture

- NUCOR's BACT determination for the DRI process considered the acid gas absorption system that will produce pure CO_2 capable of Carbon Capture and Storage (CCS). However, the draft permit does not evaluate CCS, which the EPA's GHG permitting guidance notes on pp.33-34 is an available technology for industrial facilities with high-purity CO_2 streams, which includes iron and steel production. LDEQ should provide a basis for why CCS is not considered an available technology, and if it is considered available but not technically feasible (as Nucor's 10/22/10 letter suggests), please provide a basis for such determination. See GHG permitting guidance at pp. 36-38.

Dedicated Sequestration

- Dedicated sequestration involves the injection of CO_2 into an on-site or nearby geological formation, such an active oil reservoir (enhanced oil recovery), a brine aquifer, an un-mined coal seam, basalt rock formation, or organic shale bed. Clearly, in order for geologic sequestration to be a feasible technology, a promising geological formation must be located at or very near to the facility location.
- According to the U.S. Department of Energy (DOE), no basalt formations exist any nearer to the project site than Alabama. Organic-rich shale basins and un-mineable coal areas exist in northern Louisiana, but not in the region of southeast Louisiana where the facility will be located.

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Dedicated Sequestration

- Saline formations are layers of porous rack that are saturated with brine. These formations are known to exist throughout southern Louisiana.
- LDEQ was unable to find characterization studies of saline formations in the region of southeastern Louisiana
- Due to the high degree of uncertainty in utilizing saline formations for dedicated CO_2 storage, this type of sequestration was deemed technically infeasible.
- While St. James Parish serves as a major transshipment corridor for natural gas, petroleum, and petroleum products, it was found that very few oil and gas wells exist in St. James Parish and the vicinity of Convent. Without a nearby active oil reservoir, or depleted natural gas reservoir, this option becomes technically infeasible.

Off-Site Sequestration

- Off-site sequestration of CO_2 involves utilization of a third-party CO_2 pipeline system in order to transport CO_2 to distant geologic formations that may be more conducive to sequestration than sites in the immediate area. Building such a pipeline for dedicated use by a single facility is almost certain to make any project economically infeasible. However, such an option may be effective if both adequate storage capacity exists downstream and reasonable transportation prices can be arranged with the pipeline operator.
- Denbury Resources operates a dedicated CO_2 pipeline in the general area of the proposed location of the Nucor facilities. However, the nearest branch of this pipeline is approximately 8 miles distant and across the Mississippi River. Access to this pipeline without a river crossing is approximately 20 miles.

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- In order for use of Denbury's pipeline to be viable, Nucor would, of course, have to connect to it. To do so, Nucor would have to secure the necessary right-of-ways (or perhaps purchase additional property), construct a 20-mile pipeline (or if the shorter leg is selected, tunnel under the Mississippi River), purchase additional compression equipment with ongoing electricity and maintenance requirements, and likely obtain the approval of other regulatory agencies. In sum, the feasibility of connecting to Denbury's CO_2 pipeline, both from a logistical and an economic perspective, is, at best, unknown.
- LDEQ is also concerned about any permit condition which would, in effect, direct Nucor to contract with a specific, single third party that would act in the capacity of an essential utility, especially given that Denbury's CO_2 pipeline is not regulated by the Louisiana Public Service Commission. LDEQ's position is that any such condition, regardless of the individual circumstances, is beyond the scope of a BACT determination. For this reason, transport and sequestration was eliminated from further consideration.

Just In Case You Weren't Paying Attention

- In March of this year, EPA issued four additional comments.
- The first again states that the record is not clear how Carbon Sequestration was eliminated. LDEQ's answer from the first comment did not change.
- The second still wants a lower energy consumption for producing the DRI. LDEQ stands by the documentation from the response to comments. Since this is the first facility to be built with these limits for operation, LDEQ will wait for completion of the project and for startup and operational data to determine if the limitation was satisfactory.
- The third comment was over typo errors.
- The fourth comments still wants a specific GHG emission limitation. LDEQ stands by the decision to not require such a limit.

By the Way…

- In May of this year, EPA received a petition from Louisiana Environmental Action Network (LEAN)
- They argue that the GHG limit is not BACT. The first argument is that the limit is higher than literature (Same as EPA's comment). LDEQ intends to hold to the initial response that the parameters used are not the same as from the literature and a direct comparison is not relevant.
- Second, the limit is not supported by the natural gas usage from the Nucor documentation. The petition goes on to say that their analysis of course does not include methane use as the reducing gas and therefore the petitioners analysis is incomplete and not valid.

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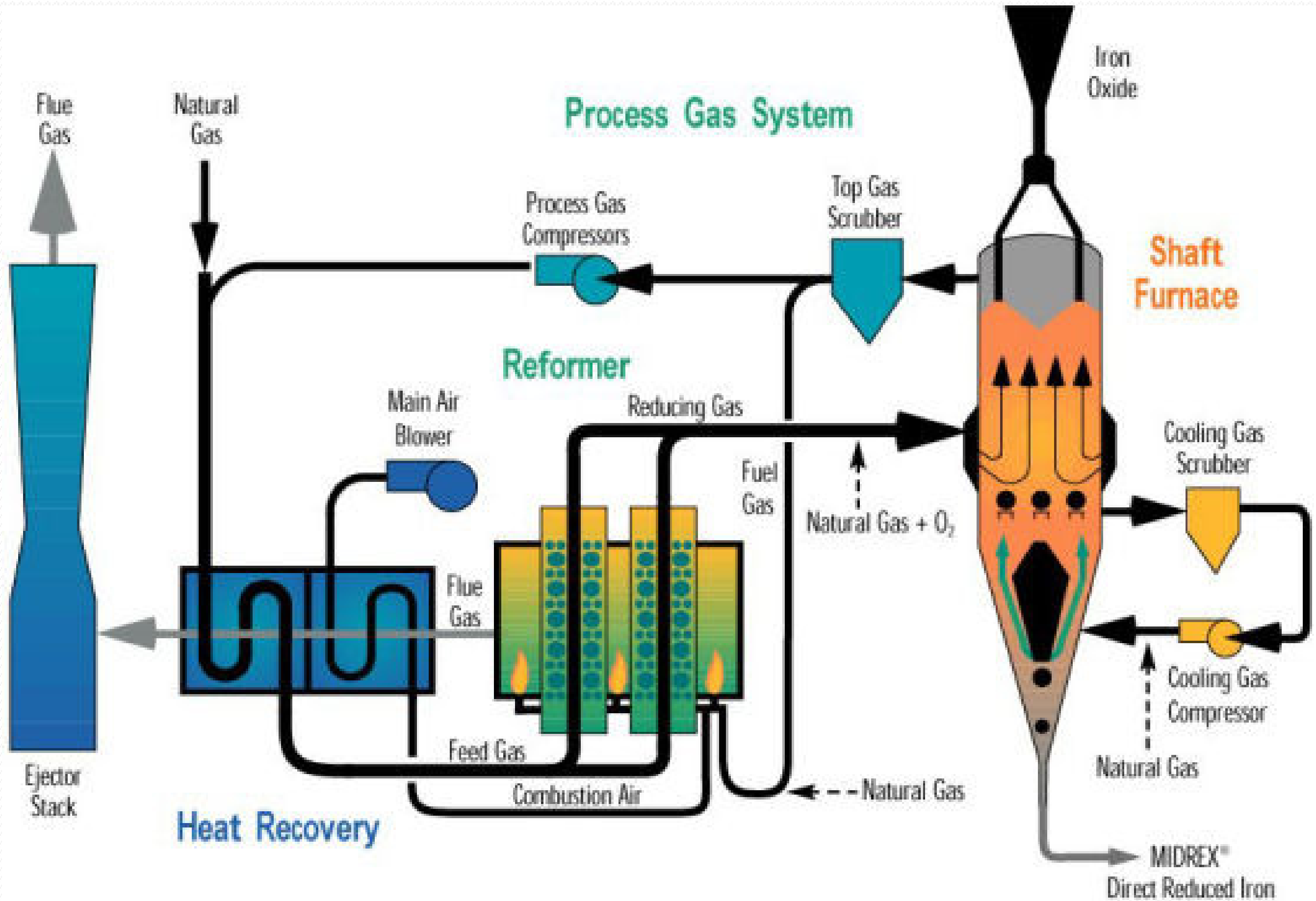
- The petitioners third comment is that the limit is only for the Reformer, not the entire facility and fourth that the limit does not specify it as BACT for GHG. This appears to be based upon the draft copy of the permit and not the final issued set where the limit **was** established for the entire facility and clearly shows the following requirements:

  BACT for **greenhouse gas (CO2e)** emissions: Limit Natural gas <= 13 MM BTU (HHV) per tonne of Direct Reduced Iron (DRI) produced. [LAC 33:III.509]

  BACT for **greenhouse gas (CO2e) emissions**: Determine compliance with the GHG BACT limitation of 13 decatherms per metric ton of DRI by maintaining a trailing twelve-month rolling average of natural gas consumption less than or equal to 13 decatherms per metric ton of DRI. The rolling average shall be calculated from the records of **actual natural gas consumption and actual DRI production required by this permit**. Maintain records of the rolling average for a period of at least five years. [LAC 33:III.509]

The MIDREX® Process consists of three major stages: 1) reduction, 2) reforming and 3) heat recovery



Reduction Process

Iron oxide, in pellet or lump form, is introduced through a proportioning hopper at the top of the shaft furnace. As the ore descends through the furnace by gravity flow, it is heated and the oxygen is removed from the iron (reduced) by counterflowing gases which have a high H_2 and CO content.

These gases react with the Fe_2O_3 in the iron ore and convert it to metallic iron, leaving H_2O and CO_2. For production of cold DRI, the reduced iron is cooled and carburized by counterflowing cooling gases in the lower portion of the shaft furnace.

The DRI can also be discharged hot and fed to a briquetting machine for production of HBI, or fed hot, as HDRI, directly to an EAF, as in the HOTLINK® System.

Just When You Thought…

- We understand Nucor will be submitting an application to modify the DRI permits to reflect a reformerless design.
- This will result in across-the-board emissions decreases.

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