BEFORE THE ADMINISTRATOR
U.S. ENVIRONMENTAL PROTECTION AGENCY

In the Matter of Title V Air Operating Permits
and Prevention of Significant Deterioration Permit
for

Consolidated Environmental
Management, Inc./Nucor Steel, Louisiana
To construct and operate a Pig Iron and Direct
Reduction Iron manufacturing facility in
Convent, St. James Parish, Louisiana

Permit No.: 2560-00281-V1 (modified pig
iron process Title V permit)
Permit No.: 3086-V0 (DRI Title V)
Permit No.: PSD-LA-751 (DRI PSD)

Issued by the Louisiana Department of
Environmental Quality

PETITION REQUESTING THE ADMINISTRATOR TO OBJECT TO TITLE V OPERATING PERMITS NOS. 2560-00281-V1 AND 3086-V0 ISSUED TO CONSOLIDATED ENVIRONMENTAL MANAGEMENT, INC. / NUCOR STEEL LOUISIANA

Pursuant to section 505(b) of the Clean Air Act, 42 U.S.C. § 7661d(b)(2) and 40 C.F.R. § 70.8(d), Louisiana Environmental Action Network ("LEAN") and Sierra Club petition the Administrator of the U.S. Environmental Protection Agency to object to the modified Title V Air Operating Permit (No. 2560-00281-V1) for the pig iron plant and the initial Title V Air Operating Permit (No. 3086-V0) for the Direct Reduced Iron ("DRI") plant issued on January 27, 2011 by the Louisiana Department of Environmental Quality ("LDEQ") to Consolidated Environmental Management Inc., Nucor Steel Louisiana ("Nucor") for its iron manufacturing facility in Convent, Louisiana.

Sierra Club and LEAN base this petition on comments that they, Zen-Noh Grain, and EPA Region 6 filed with LDEQ during the public comment period on the permits at issue. Sierra Club and LEAN also adopt and incorporate by reference Zen-Noh Grain's petition asking the EPA to object to the modified Title V permit for the pig iron plant and the initial Title V permit for the DRI plant.

SUMMARY

EPA should object to Nucor's modified pig iron Title V permit and initial DRI Title V permits because they violate the Clean Air Act and the Louisiana state implementation plan ("SIP") for the following reasons:

(1) LDEQ failed to aggregate the DRI and Pig Iron facilities and permit them under one PSD permit as one major source.

(2) LDEQ failed to apply MACT standards for the topgas boilers.

(3) LDEQ failed to include limits for PM2.5 emissions in the Title V permit for the pig iron plant and also failed to provide PM2.5 emission limits in the PSD permit for the DRI plant.

(4) Nucor's DRI Title V permit violates the Clean Air Act and the Louisiana SIP because the limit for natural gas consumption is not BACT for greenhouse gas emissions.

For these reasons, the Administrator should object to the permits within 60 days upon receipt of this petition, as required by § 505 of the Act, because they violate the applicable requirements of the Act and the Louisiana implementation plan. 42 U.S.C. § 7661d(b)(2). The Administrator should revoke the permits upon her objection. *Id.* § 7661d(b)(3).

STATUTORY AND REGULATORY FRAMEWORK

One of the primary purposes of the Title V permit program is to "enable the source, States, EPA, and the public to understand better the requirements to which the source is subject, and whether the source is meeting those requirements." 57 Fed. Reg. 32250, 32251 (July 21, 1992). Thus, a Title V permit issued by LDEQ must "incorporate all federally applicable requirements for each emissions unit at the source," LAC 33:III.507.A.3, and include "enforceable emission limitations and standards, . . . and such other conditions as are necessary to assure compliance with applicable requirements of this chapter [the CAA], including the requirements of the applicable [SIP]." 42 U.S.C. § 7661c(a). Federally applicable requirements that must be incorporated into a title V permit include standards and other requirements in the SIP, terms and conditions in a PSD permit, new source performance standards ("NSPS") promulgated pursuant to section 111 of the Act, and emission standards for hazardous air pollutants ("NESHAP" or "MACT") promulgated pursuant to section 112 of the Act. 40 C.F.R. § 70.2; LAC 33:III.502.A. A Part 70 permit cannot impose new substantive air quality control requirements or "relax any applicable requirements, including those contained in the SIP." 57 Fed. Reg 32250, 32280.

Section 505(b) of the Act, 42 U.S.C. § 7661d(b)(1), provides that "[i]f any permit contains provisions that are determined by the Administrator as not in compliance with the applicable requirements of this chapter . . . the Administrator shall . . . object to its issuance." If EPA does not object within 45 days after a permit has been proposed, any person may petition EPA (within 60 days of the expiration of the 45-day period) to take such action. A petition must be based on "objections to the permit that were raised with reasonable specificity during the public comment period . . . (unless the petitioner demonstrates in the petition to the

Administrator that it was impracticable to raise such objections within such period or unless the grounds for such objection arose after such period." § 7661d(b)(2). EPA "*shall* issue an objection" if the petitioner demonstrates that the permit is not in compliance with the requirements of the Act or SIP. *Id.* (emphasis added); *see also* 40 C.F.R. § 70.8(c)(1). The duty to object is *not* discretionary, *New York Public Interest Research Group, Inc. v. Whitman*, 321 F.3d 316, 332-33 (2nd Cir. 2003), and applies whether the petitioner demonstrates violations of either substantive or procedural requirements. *Sierra Club v. Johnson*, 436 F.3d 1269, 1280 (11th Cir. 2006).

Where a person bases the petition on violations of PSD or the SIP, EPA will generally look to see whether the petitioner has shown that the state permitting authority did not "(1) follow the required procedures in the SIP; (2) make PSD determinations on reasonable grounds properly supported on the record; [or] (3) describe the determinations in enforceable terms." *In the Matter of Louisville Gas and Electric Company, Trimble County, Kentucky*, Part 70/PSD Air Quality Permit # V-02-043 Revisions 2 and 3, Order Responding to Issues Raised in April 28, 2008 and March 2, 2006 Petitions, and Denying in Part and Granting in Part Requests for Objection to Permit, August 12, 2009, at 5.

PROCEDURAL REQUIREMENTS

LDEQ transmitted a draft permit to the Administrator for review on January 19, 2011, triggering EPA's 45-day review period as required by CAA § 505(b)(2), 42 U.S.C. § 7661d(b)(2). Sierra Club and LEAN file this petition within sixty days following the end of EPA's review period as required by CAA § 505(b)(2), 42 U.S.C. § 7661d(b)(2). The Administrator has sixty days to grant or deny this petition. *Id.* Since LDEQ has issued the permits, "the Administrator shall modify, terminate, or revoke such permit[s]" upon its objection. 42 U.S.C. § 7661d(b)(3).

SPECIFIC OBJECTIONS

I. EPA MUST OBJECT TO THE TITLE V PERMITS BECAUSE LDEQ FAILED TO AGGREGATE PSD PERMITTING FOR EMISSIONS FROM THE ENTIRE FACILITY.

EPA must object to the Title V permits because LDEQ failed to aggregate the pig iron and DRI processing units under a single PSD permit consistent with Clean Air Act's PSD requirements. *See, e.g.*, 42 U.S.C. §§ 7470-7477; 40 C.F.R. §§ 51.165, 52.21; La. Admin. Code tit. 33, pt. III, § 509. By issuing separate PSD permits for the pig iron process and DRI process, LDEQ allowed Nucor to circumvent the air quality impact analysis prerequisites. For example, LDEQ did not require Nucor to perform the air quality impact modeling -- for NAAQS review and preconstruction monitoring applicability -- for all emission sources in the aggregate facility. Instead, for sulfur dioxide ("SO2") and particulate matter ("PM10" and "PM2.5"), Nucor modeled only emissions from the DRI process, and found them to be below the SIL.

Furthermore, by permitting Nucor's DRI and pig iron units separately, LDEQ has deprived the public of the opportunity to review and comment on the aggregate emissions and air quality impacts from the whole plant. And by piecemealing the permits, LDEQ has failed to require PSD review for greenhouse gases (GHG) for the entire plant. Instead of two PSD permits, one of which contains a GHG analysis and another which contains no GHG analysis, one PSD permit must be issued for the entire Nucor plant.

The pig iron and DRI processes are part of a single "source," so LDEQ must permit them together, not as two separate sources. The Louisiana SIP mandates PSD permits for "the construction of any new *major stationary source*." LA. ADMIN. CODE, tit. 33, pt. III, § 509(A)1 (emphasis in original). The SIP defines "stationary source" as any "building, structure, facility, or installation that emits or may emit any pollutant subject to regulation under this Section." LA. ADMIN. CODE, tit. 33, pt. III, § 509(B). The SIP further defines a "source" such that it shall encompass "all of the pollutant-emitting activities which belong to the same industrial grouping [*i.e.*, same two-digit SIC code], are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control)." *Id.*; *see also* 40 C.F.R. § 51.166(b)(6) (same). This definition creates a simple three-pronged test to determine whether a group of pollutant-emitting activities is a single source requiring a single PSD permit.[1] A regulator needs only to determine if the activities belong to the same owner, are next to each other or on the same parcel of property, and fall within the same two-digit SIC code.

Here, the two iron smelting activities meet all three prongs of the "stationary source" test, and thus should be subjected to a single PSD permit. First, Nucor is locating the pig iron and DRI process pollutant-emitting activities on the same parcel of land in St. James Parish. The property is contiguous, and even shares the same roads and water service system. Second, Nucor owns and controls both pollutant-emitting activities, and operationally both will be subject to the same management structure. *See* La. Electronic Document Management System (EDMS) Doc. No. 7731641, at 372, 378; EDMS Doc. No. 7731649, at 404, 409. Third, both of the pollutant-emitting activities are iron foundries. All "iron & steel foundries" such as the Direct Reduced Iron foundry and the Pig Iron foundry here, share one SIC code—code 3320.[2]

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[1] *See In the Matter Of Kerr-McGee/Anadarko Petroleum Corporation*, *Frederick Compressor Station* (Permit Number: 950PWE035), Order Responding to Petitioners' Request that the Administrator Object to Issuance of a State Operating Permit, Oct. 8, 2009 [hereinafter, *Anadarko Order*] (applying three-part test to determine the source).

[2] *See* Securities & Exchange Commission, Division of Corporation Finance, Standard Industrial Classification (SIC) Code List, *available at* http://www.sec.gov/info/edgar/siccodes.htm. Note that the Administrator required only that the SIC codes for both activities be within a "major group", i.e., groups sharing the same first two digits of the four digit code. Here, both DRI and Pig Iron fall within precisely the same code – Iron and Steel Foundries, code 3320. *See id.*

II. EPA MUST OBJECT TO THE TITLE V PERMIT FOR THE PIG IRON PROCESS BECAUSE THE PERMIT FAILS TO APPLY MACT STANDARDS FOR THE TOPGAS BOILERS.

As LDEQ acknowledges, the Nucor pig iron complex is a "major source" of hazardous air pollutants under § 112 of the Clean Air Act.[3] The Title V permit for the pig iron plant, however, violates Clean Air Act § 112(j) by failing to impose case-by-case MACT standards for the facility's industrial boilers. *See* 42 U.S.C. § 7412(j)(5) (requiring that the "permit . . . shall contain emission limitations for the hazardous air pollutants subject to regulation under this section and emitted by the source that the Administrator (or the State) determines, on a case-by-case basis, to be equivalent to the limitation that would apply [if EPA had timely promulgated a standard]."). The permit is also invalid because it fails to "include enforceable emission limitations and standards . . . as are necessary to assure compliance with applicable requirements of this Act" because it does not contain emissions limits consistent with § 112(j)(5). 42 U.S.C. § 7661(c) (mandating conditions for Title V permits). Moreover, construction of the facility would be illegal under the Clean Air Act § 112(g)(2), codified at 42 U.S.C. section 7412(g)(2). *See Sierra Club, Inc. v. Sandy Creek Energy Associates*, --- F.3d ----, 2010 WL 4725044 (5th Cir. 2010) (finding construction of a coal-fired electric generating plant that failed to receive a final MACT determination for its boiler in violation of § 112(g) of the Clean Air Act).

Under §112(c) of the Clean Air Act, EPA created source categories for major sources that emit one or more hazardous air pollutants listed in §112(b).[4] The category of industrial boilers is defined as "a boiler used in manufacturing, processing, mining, and refining or any other industry to provide steam, hot water, and/or electricity." 40 C.F.R. 63.7575 (2009). Nucor's topgas boilers fit within the EPA's definition of industrial boilers.

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[3] Title V/Pig Iron/Air Permit Briefing Sheet, p. 7.

[4] Robert J. Martineau, Jr., *Hazardous Air Pollutants* in Clean Air Act Handbook, 227, 239 (Robert J. Martineau, Jr. and David P. Novello eds., 2004).

EPA was required under the Clean Air Act to set maximum achievable control technology (MACT) standards for all major industry source categories by November 15, 2000.[5] EPA failed to meet this deadline to establish MACT standards for the industrial boilers category. It was not until January 13, 2003 that EPA proposed a rule for industrial boiler standards.[6] EPA's final rule for industrial boilers was published December 6, 2006.[7] However, on July 30, 2007 the D.C. Circuit vacated and remanded EPA's Boilers Rule.[8] EPA has promulgated new rules, but those are not yet effective.

The fact that EPA's MACT rule for industrial boilers is not yet effective does not mean that states and regulated parties are off the hook for regulating boilers. Section 112(j) of the Clean Air Act provides that in the event EPA fails to meet its deadline to promulgate standards, regulated parties are required to submit permit applications beginning 18 months after the deadline date.[9] This 18-month period after the deadline for industrial boiler standards ended on May 15, 2002. Therefore, under §112(j) of the Clean Air Act, regulated parties are required to submit permit applications as of May 15, 2002 that include MACT standards for industrial boilers.

Section 112(j) and 40 C.F.R. §§ 63.50-63.56 are applicable requirements, and EPA must object to the Title V Permit because LDEQ failed to require them.

III. EPA MUST REJECT THE PERMITS BECAUSE LDEQ FAILED TO INCLUDE EMISSION LIMITS FOR PM2.5.

LDEQ failed to include limits for PM2.5 emissions in the Title V permit for the pig iron plant. As applicable requirements from the PSD permit, the Title V permit must include limits

[5] 58 Fed. Reg. 63941 (Dec. 3, 1993).
[6] 68 Fed. Reg. 1660 (Jan. 13, 2003).
[7] 71 Fed. Reg. 70651 (Dec. 6, 2006).
[8] *NRDC v. EPA*, No. 04-1385, (D.C. 2007).
[9] Clean Air Act, 42 U.S.C. §7412(j)(1-3).

for PM2.5. EPA must object to this Title V permit because it does not include emission limits for PM2.5. Furthermore, LDEQ failed to provide PM2.5 emission limits in the PSD permit for the DRI plant. Here, EPA must object to the Title V for the DRI plant because the PSD does not include limits for PM2.5.

LDEQ concluded that PM10 is an adequate surrogate for PM2.5. But LDEQ failed to provide a case specific demonstration that its use of PM10 as a surrogate for PM2.5 is reasonable under the facts and circumstances of this permit.

In 1997, the EPA set forth an interim policy that allowed permitting authorities to use "PSD and NSR program requirements for controlling PM10 emissions" as a surrogate approach for reducing PM2.5 emissions," where it proved "administratively impracticable" to directly address PM2.5 due to "technical and information deficiencies." However, in 2008, the EPA announced that as a result of technical developments and EPA actions, those technical "difficulties have largely been resolved," but allowed some continued use of the surrogate policy. 73 Fed. Reg. 28,321, 28,340-41 (May 16, 2008).

On August 12, 2009 EPA issued an order that a permit applicant may not avoid its obligation to assess the impacts of, and controls for, PM2.5 merely by providing an analysis of PM10. *In re: Louisville Gas & Electric Co., Trimble County, Kentucky, Petition No. IV-2008-3*, Order Responding to Issues Raised in April 28, 2008 and March 2, 2006 Petitions, and Denying in Part and Granting in Part Requests for Objection to Permit at 42 (Aug. 12, 2009), at 44. In order to use EPA's PM10 surrogate policy, the permit applicant would have to provide a case specific demonstration that such use is reasonable under the facts and circumstances of the permit. *Id.* The EPA stated that this demonstration must include: (1) a showing of sufficient correlation between the plant's PM10 and PM2.5 emissions so as to provide "confidence that the statutory requirements will be met for PM2.5 using the controls selected through a PM10 NSR analysis" and (2) a showing "that the degree of control of PM2.5 by the control technology selected in the PM10 BACT analysis will be at least as effective as the technology that would have been selected if a BACT analysis specific to PM2.5 had been considered." *Id*. at 45.

Although the EPA may sometimes allow use of the surrogate policy, this is dependent upon "a case-by-case evaluation of the use of PM10 in individual permits." *See* Letter from Stephen Johnson to Paul Cort, (Jan. 14, 2009) at 3.[10] This case-by-case analysis is also required by governing case law. *E.g., National Lime Assoc. v. EPA*, 233 F.3d 625, 637 (D.C. Cir. 2000) (stating agency may substitute control of surrogate substance only where it shows (1) that regulated pollutant is invariably present in surrogate, (2) surrogate control technology indiscriminately captures regulated pollutant, and (3) surrogate control technology are only means by which regulated pollutant may be reduced); *Mossville Envtl. Action Now v. EPA*, 370 F.3d 1232, 1242-43 (requiring reasoned explanation of correlation between surrogate and regulated pollutant).

EPA must object to the Title V permits for failure to include PM2.5 limits and failure to provide an appropriate analysis on the pollutant.

IV. THE LIMIT FOR NATURAL GAS CONSUMPTION IS NOT BACT FOR GHG EMISSIONS FROM THE DRI FACILITY

In Step 4 of the BACT analysis for GHG emissions, the PSD Permit concludes that natural gas consumption is the most relevant parameter that can be measured and that the minimization of natural gas consumed by the process is the most effective means of reducing GHG generation. As an evaluation, the PSD Permit quotes verbatim the following paragraph from Nucor's GHG BACT Analysis:

[10] Available at http://www.epa.gov/nsr/documents/20090115cort.pdf.

> Historical rates of GHG emissions for the DRI process, measured using the unit metric of natural gas consumption per tonne of product has decreased over time as market forces have driven process efficiency. Early designs of the DRI process could be expected to meet an efficiency of 15 decatherms of natural gas per tonne of DRI produced. This efficiency metric has gradually fallen over several years, until the current-day state of the art is expected to require no more than 13 decatherms of natural gas per tonne DRI.[11]

Neither the Nucor's GHG BACT Analysis nor the PSD Permit contains any documentation for this statement.

Based on this discussion, the PSD Permit in Step 5 of the BACT analysis for GHG emissions determines a numerical limit for the consumption of natural gas and discusses compliance with this limit for the Reformer/Main Flue Gas Stack (DRI-108/208):

> Due to production rate and product quality variability in any production process, production rates should be inclusive of all production at the facility, both of regular and off-spec materials. Additionally, natural gas is consumed in the DRI process as both a raw material (for the formation of reducing gas) and as a fuel (for heating to reaction temperatures). All sources of natural gas consumption at the Reformer should be included in the analysis. BACT is no more than 13 decatherms of natural gas per tonne of DRI (11.79 MM Btu/ton of DRI). Compliance with the BACT limit shall be determined on the basis of total natural gas consumption, divided by total production (including regular and off-spec DRI product) of the facility on a 12-month rolling average.[12]

The Title V Permit implements this determination in the following condition for the Reformer/Main Flue Gas Stack in Train #1 of the DRI facility only (DRI-108):

> *Specific Requirement #81:*
> BACT is Natural [sic] gas <= 13 MMBTU per Tonne [sic] of Direct Reduced Iron (DRI) produced. Compliance with the BACT limit shall be determined on the basis of total natural gas consumption, divided by total production (including regular and off-spec DRI product). Which Months: All Year, Statistical Basis: Twelve-month rolling average (rolling 1-month basis)

[11] *Id*. at, p. 48, EDMS Document 7731649, p. 107 of 82.3

[12] PSD Permit for DRI Facility, PSD-LA-751, November 8, 2010, Preliminary Determination Summary, Section IV.A Best Available Control Technology, pp. 45-48, EDMS Document 7731649, pp. 104-107 of 823.

There are a number of problems with this BACT determination. First, the limit for natural gas consumption for DRI production determined by Nucor and the PSD is considerably higher than reported in the literature. Second, this limit is not supported by the values for natural gas consumption used by Nucor for calculation of criteria pollutant emissions from the DRI facility. Third, the PSD Permit incorrectly identifies this limit not for the entire facility but rather only for the Reformer/Main Flue Gas Stack (DRI 108) in Train #1 of the DRI facility. Fifth, the Title V Permit fails to state that this is a BACT limitation for GHG.

A. Lower Natural Gas Consumption for DRI Production Is Reported in the Literature.

As mentioned above, neither Nucor's GHG BACT Analysis nor the PSD Permit contain any documentation for the conclusion that a consumption of 13 decatherms of natural gas per tonne of DRI produced is BACT for GHG emissions from the DRI facility. Review of the literature shows that considerably lower values are reported for DRI processes for both other facilities and for DRI production processes. Table 2 below summarizes reported values for natural gas consumption as well as electricity consumption for specific DRI facilities in the U.S. and Australia and for several DRI production processes, including Midrex, HYL, and Finmet. (For comparison purposes, all reported values for natural gas consumption were converted to million British thermal units per tonne of DRI produced ("MMBtu/tonne DRI").)

Table 2: Reported values for natural gas consumption and electricity consumption for DRI facilities

	DRI Process	**Natural Gas Consumption** (calculated)[a]	**Electricity Consumption**
		Facility-specific *(status)*	
Nucor DRI Facility, Convent, LA *(draft permits)* Capacity: 5.0×10^6 tonnes DRI/year	n/a	13 decatherms/tonne DRI[1] **13 MMBtu/tonne DRI**	n/a
Austeel Pty Ltd, Cape Preston, Australia	Midrex	55,280 TJ/year[2] (at capacity)	n/a

(permitted) Capacity: 5.6×10^6 tonnes DRI/year[b]		**(9.7 MMBtu/tonne DRI)**	
Essar Steel Minnesota, Nashwauk, MI *(under construction)* Capacity: 2.8×10^6 tonnes DRI/year	Midrex[c]	8-9 MMBTU/ton DRI[3] **(7.3-8.2 MMBtu/tonne DRI)**	n/a
Process-specific			
	HYL	2.25 to 2.3 Gcal/ton DRI[4] **(9.8-10.0 MMBtu/tonne DRI)**	**60 to 80 kWh/ton DRI**[4]
		10.7 million kJ/tonne DRI[5] **(10.1 MMBtu/tonne DRI)**	**90 kWh/tonne DRI**[2]
	Midrex	**10.30 MMBtu/tonne DRI**[2]	**130 kWh/tonne DRI**[2]
	HYL III[d]	**11.33 MMBtu/tonne DRI**[2]	n/a
	Finmet[e]	**11.55 MMBtu/tonne DRI**[2]	**150 kWh/tonne DRI**[2]

Notes:

n/a not available

a calculated using the following conversion factors: 1 Btu = 1.055 J (at 59 F); 1 Btu ≈ 252-253 cal (average 252.5 cal);
1 tonne = 1.1023 ton

b The facility produces DRI and hot briquetted iron ("HBI"), a compacted form of DRI designed for ease of shipping, handling, and storage; because there is no additional natural gas demand for the briquetting process of DRI, natural gas consumption figures for DRI and HBI are directly comparable

c Direct feed of DRI to electric arc furnace

d Proposed for use by Mineralogy Pty Ltd, Ausi Iron Project, Australia (capacity: 4×10^6 tonnes HBI/year)

e Proposed for use by BHP Billiton, Boodarie, Australia

Sources:

1 Draft PSD Permit for DRI Facility, PSD-LA-751, November 8, 2010, Preliminary Determination Summary, Section IV.A Best Available Control Technology, p. 48, EDMS Document 7731649, p. 104 of 823.

2 Mineralogy Pty Ltd., Iron Ore Mine and Downstream Processing, Cape Preston, Western Australia, Greenhouse Gas Management Plan, November 2006, p. 12, citing Feinman et al. 1999, Direct Reduced Iron, Technology and Economics of Production and Use, Chapter 14: Economics of Production and Use of DRI; available at http://www.citicpacificmining.com/resources/Greenhouse_Gas_Management_Plan.pdf.

3 J.J. Poveromo, Raw Materials & Ironmaking Global Consulting, A Report on the 82nd Annual Meeting – Minnesota Mining Symposium, Steel Times International, September 2009; available at http://www.steeltimesint.com/contentimages/features/Raw_Materials_Report.pdf.

4 InTech, Hot Iron, Iron Reduction Technology Keeps Plant Shutdown Safe, Trip Free, December 2008; available at http://snipurl.com/1r0hfi [www_google_com].

5 Manufacturer quote cited in: Government of India, Central Pollution Control Board, Ministry of Environment and Forests, Sponge Iron Industry, March 2007, Comprehensive Industry Documents Series COINDS /66/2006-07, p. 46; available at http://www.cpcb.nic.in/upload/NewItems/NewItem_102_SPONGE_IRON.pdf.

As shown in Table 2, the value of 13 decatherms (or MMBtu[13]) of natural gas consumed per tonne of DRI produced determined by Nucor and the PSD Permit as BACT is considerably higher than reported in the literature for other facilities and for the various DRI production processes which range from 7.3 to 11.55 MMBtu/tonne DRI produced.

The lowest value for natural gas consumption, 7.3-8.2 MMBtu/tonne DRI (8-9 MMBtu/ton DRI), was estimated for the Essar Minnesota Steel (formerly Minnesota Steel Industries, LLC) project at the former Butler Mine on the Mesabi iron ore range Minnesota. The facility is currently under construction and expected to be operational end of 2012.[14] The facility will be the first fully-integrated mine through steel-making facility in North America and will produce about 3.1 million tons (2.8 million tonnes) per year of DRI[15] (56 percent of the proposed Nucor DRI facility). The DRI process will use a Midrex shaft furnace and DRI product will be discharged directly to the electric arc furnace.[16] Clearly, the limit of 13 MMBtu/tonne DRI produced is not BACT for GHG emissions.

[13] 1 decatherm = 10 therms; 1 therm = 100,000 Btu.

[14] Steel Guru, First Concrete Poured at Essar Steel Minnesota, November 1, 2010; available at http://www.steelguru.com/international_news/First_concrete_poured_at_Essar_Steel_Minnesota_site/172890.html.

[15] Minnesota Department of Natural Resources, Minnesota Steel, Final Environmental Impact Statement, June 2007, p. EX-2; available at http://files.dnr.state.mn.us/input/environmentalreview/minnsteel/feis/feis_1.pdf.

[16] J.J. Poveromo, Raw Materials & Ironmaking Global Consulting, A Report on the 82nd Annual Meeting – Minnesota Mining Symposium, Steel Times International, September 2009; available at http://www.steeltimesint.com/contentimages/features/Raw_Materials_Report.pdf.

B. <u>The Sum of Values for Natural Gas Consumption Used by the Nucor for Calculation of Criteria Pollutant Emissions from the DRI Facility Is Less Than Half the BACT Limit</u>.

In the calculations of criteria pollutant emissions from the DRI facility, Nucor used the following maximum (average) firing rates:

Reformer/Main Flue Gas Stack (DRI-108/208):	1,597 (1,521) MMBtu/hour
Package Boiler (DRI 109/209):	290 (220) MMBtu/hour
Hot Flare (DRI-110/210) pilot:	160 (149) scf/hour

Based on the maximum annual hours of operation for the Reformer/Main Flue Gas Stack (DRI-108/208) and the Package Boiler (DRI 109/209) (8,000 hours/year) and the Hot Flare pilot (8,760 hours/year) and a higher heating value for natural gas of 1,020 British thermal units per standard cubic foot ("MMBtu/scf"),[17] the annual natural gas consumption on a per-unit-basis can be estimated as follows:

Reformer/Main Flue Gas Stack (DRI-108/208):	1.28×10^7 (1.22×10^7) MMBtu/year[18]
Package Boiler (DRI 109/209):	2.32×10^6 (1.76×10^6) MMBtu/year[19]
Hot Flare (DRI-110/210) pilot:	1.46×10^3 (1.33×10^3) MMBtu/year[20]

Therefore, total annual natural gas consumption for both trains of the DRI facility can be estimated at 3.02×10^7 MMBtu/year (2.79×10^7 MMBtu/year).[21] Based on the maximum annual

[17] Letter from Timothy M. Desselles and Matthew J. Skific, Environmental Resources Management, to Cheryl Nolan, Lousiana Department of Environmental Quality, Re: Addendum to Initial Part 70 Permit Application, Consolidated Environmental Management, Inc., Nucor Steel Louisiana – Direct Reduced Iron Facility, October 22, 2010, EDMS Document 7712779.

[18] Maximum: (1,597 MMBtu/hour)(8,000 hours/year) = 1.28×10^7 MMBtu/year per reformer; Average: (1,521 MMBtu/hour)(8,000 hours/year) = 1.22×10^7 MMBtu/year per reformer.

[19] Maximum: (290 MMBtu/hour)(8,000 hours/year) = 2.32×10^6 MMBtu/year per package boiler; Average: (220 MMBtu/hour)(8,000 hours/year) = 1.76×10^6 MMBtu/year per package boiler.

[20] Maximum: (163 scf/hour)(1,020 Btu/scf)(MMBtu/10^6 Btu)(8,760 hours/year) = 1.46×10^3 MMBtu/year per hot flare pilot;
Average: (220 MMBtu/hour)(1,020 Btu/scf)(MMBtu/10^6 Btu)(8,760 hours/year) = 1.33×10^3 MMBtu/year per hot flare pilot.

production of 5.0 million tons of DRI per year for both trains of the DRI facility, natural gas consumption on a per unit basis can be estimated at 6.0 (5.6) MMBtu/tonne of DRI,[22] less than half the value of 13 MMBtu/tonne DRI determined to be BACT by Nucor and the PSD Permit. Thus, unless there are other major natural gas-consuming processes that the permits did not disclose, BACT for natural gas consumption as a parameter for GHG emissions for the facility is 6.0 MMBtu/tonne of DRI.

Note that LDEQ argues that Petitioners' estimates of CO2 emissions for the reformer/main flue gas, package boiler and flare did not account for the generation of reducing gas; however, LDEQ fails to provide an estimate of how much reducing gas is required to determine the total natural gas consumption. Thus, the GHG BACT limit of 13 MMBtu of natural gas consumed per tonne DRI produced remains unsupported.

Information from MIDREX indicates a typical natural gas consumption of 9.3 MMBtu/tonne DRI (2.53 Gcal/tonne DRI) at a 93% metallization and a 2.0% carbon content for the traditional MIDREX reformer. Estimating natural gas consumption at the high end of the range of metallization and carbon content results in 10.1 MMBtu/tonne DRI with 96% metallization and 10.6 MMBtu/tonne DRI with a carbon content of 2.5% carbon content. These values are on the same order of magnitude as those discussed in Petitioners' comments and far below the natural gas consumption of 13 MMBtu per tonne DRI with unspecified metallization and carbon content.

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[21] Maximum: [(1.28×10^7 MMBtu/year per reformer)+(2.32×10^6 MMBtu/year per package boiler)+
(1.46×10^2 MMBtu/year per hot flare pilot)](2) = 3.02×10^7 MMBtu/year;
Average: [(1.22×10^7 MMBtu/year per reformer)+(1.76×10^6 MMBtu/year per package boiler)+
(1.33×10^2 MMBtu/year per hot flare pilot)](2) = 2.79×10^7 MMBtu/year.

[22] Maximum: (3.02×10^7 MMBtu/year)/(5.0×10^6 tonne DRI/year) = 6.0 MMBtu/tonne DRI;
Average: (2.79×10^7 MMBtu/year)/(5.0×10^6 tonne DRI/year) = 5.6 MMBtu/tonne DRI.

In other words: the 13 MMBtu/tonne DRI seems to be a guess rather than a number that is supported by any calculations. LDEQ must provide product and raw material specifications backed by vendor information and demonstrate how it derived the 13 MMBtu/tonne DRI natural gas consumption figure.

V. THE PERMITS MUST SPECIFY PROCEDURES FOR ESTIMATING GREENHOUSE GASES.

The PSD permit must clearly specify the procedure for making the mass balance calculation for carbon in the DRI production process.[23] Specific Requirement #82, which requires calculating DRI production rates and natural gas consumption "using both the fuel consumption tracking method of Subpart C, as well as Subpart Q for iron and steelmaking from the promulgated Mandatory Reporting of Greenhouse Gas rule" is not adequate.[24]

Subpart Q for iron and steelmaking from the promulgated Mandatory Reporting of Greenhouse Gas rule does not provide a calculation procedure for DRI production and the reference is therefore moot. Therefore, EPA must require LDEQ to develop a calculation procedure for DRI production and present it for public review.

This calculation procedure must account for the fact that the carbon content and heating values of pipeline-grade natural gas can show considerable variation over space and time, as shown in Figure 1.

[23] EPA's Review of Proposed Title V Permits for Florida Power & Light, December 11, 1997, Enclosure 3, p. 2 ("In order to constitute a practically enforceable requirement, this condition must be revised to clearly specify the procedures for calculating the sulfur content of the oil on a 12-month basis.").

[24] Part 70 Air Operating Permit for DRI Facility, Specific Requirements #81 and #82, pp. 8-9 of 29, EDMS Document 7731649, pp. 37-38 of 823.

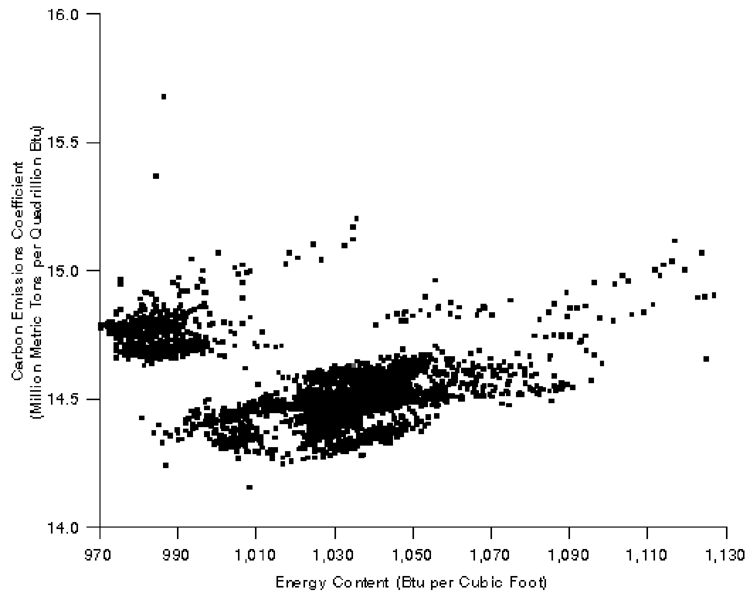

Figure 1: Carbon emissions coefficient vs. energy content in U.S. pipeline-grade natural gas
Source: Energy Information Administration, Emissions of Greenhouse Gases in the United States 1987-2002, Figure A-1; available at http://www.eia.doe.gov/oiaf/1605/archive/87-92rpt/appa.html#figure_a1.

The U.S. Department of Energy ("DoE") reports CO_2 fuel efficiency coefficients for pipeline natural gas ranging from 54.01 kg CO_2/MMBtu (5.401 kg CO_2/therm) at a higher heating value ("HHV") of 975-1,000 BTU per cubic foot ("Btu/scf") of natural gas to 53.72 kg CO_2/MMBtu (5.372 kg CO_2/therm) at an HHV of 1,075-1,100 Btu/scf.[25] Given this variability in fuel composition, facility-specific values for carbon content and heating value should be used to determine GHG emissions from natural gas combustion wherever possible. This information should be available from suppliers or Material Data Safety Sheets for the purchased fuel and should be confirmed with fuel analysis results.

Note that LDEQ's response to this comment does not lay out a procedure for estimating GHG emissions, but rather only clarifies which processes, products, and combustion sources account

[25] U.S. Department of Energy, Voluntary Reporting of Greenhouse Gases Program, Fuel Emission Coefficients; available at http://www.eia.doe.gov/oiaf/1605/coefficients.html.

for the natural gas consumption. Further, LDEQ's response does not specify the CO_2 fuel efficiency coefficient for the pipeline natural gas as discussed in Petitioners' comments.

CONCLUSION

For these reasons, the Administrator should object to the permits within 60 days upon receipt of this petition, as required by § 505 of the Act, because they violate the applicable requirements of the Act and the Louisiana implementation plan. 42 U.S.C. § 7661d(b)(2). The Administrator should revoke the permits upon her objection. 42 U.S.C. § 7661d(b)(3).

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