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<u>VIA OVERNIGHT MAIL AND EMAIL</u>
presson@michigan.gov & hellwigv@michigan.gov

Mr. William Presson
Acting Permit Section Supervisor
Air Quality Division
Department of Environmental Quality
Constitution Hall, 3rd Floor North
525 West Allegan Street
Lansing, MI 48933-1502

Re: Comments on the Draft Prevention of Significant Deterioration Construction Permit for University of Northern Michigan Boiler.

Dear Mr. Presson:

These comments are submitted on behalf of the Sierra Club and its 800,000 members, including over 30,000 members in Michigan and Wisconsin. At the outset we note that we support NMU's decision to consider steps to reduce its current reliance on aging coal-fired power plants for its electricity needs and strongly support co-generation as an efficient and low-polluting option for meeting the campus' steam and electricity needs. At the same time, it is not apparent that NMU has demonstrated that it needs a cogeneration plant as large as proposed, or that it has considered the environmental impacts of using wood from nearby forests as a fuel source or the global warming impacts of using coal as a fuel source.

Exhibit 2

The Nobel Peace Prize winning International Panel on Climate Change, which includes NMU Alumnus Professor Fritz Nelson, has urged urgent action to achieve global warming pollution reductions in the range of 25-40 percent by 2020 and 80-90 percent by 2050. Any long-term decision about how NMU meets its energy needs, such as building a new power plant, must be consistent with these reduction targets. Before investing tens of millions of dollars on a new power plant is the opportune time to assess how such reductions can be achieved and for NMU to demonstrate its commitment to environmental stewardship.

Because of these concerns we urge NMU to pull back its application and this draft permit and conduct, at a minimum, the following: 1) a campus-wide assessment of all cost-effective energy efficiency measures that could minimize the size needed for a new power plant, 2) a campus-wide assessment of all potential renewable energy options that don't emit any global warming pollutants, 3) a campus-wide assessment of how NMU will meet the global warming pollution reduction targets urged by the IPCC, and 4) assess the environmental impacts associated with mining, drilling or harvesting the fuel source that NMU ultimately selects.

Specific Comments

The Michigan Department of Environmental Quality ("MDEQ") proposes to issue a permit to the Northern Michigan University ("NMU") for a new boiler and associated equipment at the site of the existing Ripley Heating Plant. According to the applicant, the new boiler will have the ability to, and should be required to burn 100% "waste wood," a term which is not defined.

Congress intended to ensure that major sources of air pollution like the proposed Ripley Heating Plant ("Ripley") boiler do not degrade air quality for those who live and work in the areas where they are located. Congress recognized that generic national ambient air quality standards ("NAAQS") do not adequately protect people. NAAQS "do not adequately protect against genetic mutations, birth defects, cancer, or diseases caused by long-term chronic exposures or periodic short-term peak concentrations, and hazards due to derivative pollutants and to cumulative or synergistic impacts of various pollutants; and they do not adequately protect against crop damage and acid rain." *Hawaiian Elec. Co. v. U.S. Envt'l Protection Agency*, 723 F.2d 1440, 1447 (9th Cir. 1984). NAAQS also do not prevent the deterioration of otherwise cleaner air regions from deteriorating to the NAAQS "floor." For these reasons, Congress enacted the Prevention of Significant Deterioration ("PSD") provisions of the Clean Air Act. 42 U.S.C. §§ 7470, *et seq.* EPA, MDEQ, and the applicant rely upon the EPA's *New Source Review Workshop Manual* ("NSR Manual") in implementing the PSD program. *See* Application at 33.

I. MDEQ HAS NOT PROVIDED A SUFFICIENT ANALYSIS OF THE IMPACTS FROM THE PROPOSED PLANT.

An application for a PSD permit must include, among other information, "a description of the nature, location and typical operating schedule..." of the plant. 40 C.F.R. § 52.21(n)(1)(i). Additionally, the applicant must provide an analysis of impacts of the proposed plant on soils and vegetation, as well as commercial and industrial growth associated with the proposed modification. 40 C.F.R. § 52.21(o). We note that there is no such information for this source, especially as to the impacts of the fuel acquisition, including impacts on endangered species of vegetation.

The proposed plant will be fired on either 100% "waste wood," 100% coal, or some mix of the two. There is no information in the materials provided by the state indicating the source of the "waste wood" and whether this term includes the harvesting of uncut, standing timber. If the applicant is proposing to burn uncut, standing timber, the source of the fuel could have significant environmental impacts. For example, increased logging of existing forest lands could impact the region's biodiversity, endangered species dependant on large swaths of uncut older forests, and water quality. If the applicant is proposing to use uncut standing timber (i.e. green wood) and this may cause the planting of non-native tree species, or the growing of a single species of tree (monoculture) on large areas of existing forest land, that too could have significant environmental impacts on the soils, vegetation, and consequently the biodiversity of the area. If the applicant is proposing to burn waste wood that would otherwise be discarded and serve as an important source of soil nourishment that too can have significant impacts on the soils of Northern Michigan. Prior to granting this permit and the close of the public comment period, the PSD application and MDEQ must undertake a thorough review of the impacts to soil and vegetation, commercial and industrial growth, as well as other environmental impacts, associated with the proposed harvesting of forest resources to supply fuel for the facility.

Similarly, there is no information in the materials provided by the state or the applicant disclosing the source of the proposed coal, and the environmental impacts, including soil and vegetation impacts, associated with mining, transporting and burning such coal. The impacts of mining coal vary depending on the source of the coal. If the proposed coal source is Appalachia, the impacts may include destruction of entire mountains and the soils and vegetation thereon, the filling of thousands of miles of streams, and the loss of some of the richest biodiversity in North America. If the proposed coal source is Illinois, the impacts from long-wall mining include the destruction of high-quality farmland, drying up of streams and springs, and the loss of life-sustaining soil. If the proposed coal source is the Powder River Basin, the impacts from open pit mining involve removing the soils and vegetation entirely. This analysis must be done and provided to the public prior to the closing of the public comment period if the permit will allow combustion of coal.

II. THE DRAFT PERMIT DOES NOT INCLUDE SUFFICIENT BACT LIMITS

The new boiler and associated equipment is subject to stringent air pollution control requirements under the Clean Air Act's Prevention of Significant Deterioration ("PSD") program, 42 U.S.C. § 7470, *et. seq*. MDEQ has been delegated the authority to issue PSD permits on behalf of the United States Environmental Protection Agency ("USEPA") and is required to following the policy and regulations of the USEPA. Specifically, MDEQ must ensure that all new and modified emission sources at the Ripley plant are subject to emission limits that are to be based on the "best available control technology" or "BACT" and that the facility does not exceed ambient air quality standards or maximum increase over baseline (i.e., "increment") during worst-case conditions. 42 U.S.C. § 7475(a)(4); 40 C.F.R. § 52.21(j).

BACT is "one of the most critical elements of the PSD permitting process." *In re Knuaf Fiber Glass, GmbH*, 8 E.A.D. 121, 131 (EAB 1999) ("Knauf I"). BACT is defined as:

> an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or 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.

40 C.F.R. § 52.21(b)(12). To ensure that the BACT determination is "reasonably moored" to the Clean Air Act's statutory requirement that BACT represent the maximum achievable reduction through the use of various pollution control techniques, U.S. EPA established a top-down analysis process outlined in the NSR Manual. *Alaska Dept. of Envt'l Conservation v. Envt'l Protection Agency*, 540 U.S. 461, 485 (2004). This process must be followed. *Alaska v. US EPA*, 298 F.3d 814 (9th Cir. 2002).

To ensure that the limits in the final PSD permit ensure "maximum degree of reduction," based on applicable production processes, fuel cleaning, clean fuels, and other pollution control techniques, the permit applicant is required to propose a permit limit that constitutes BACT and to supply sufficient information on the control option used to achieve that limit. Specifically, the applicant must provide a detailed description of the system of continuous emissions reduction planned for the source or modification, emission estimates, and any other information necessary to ensure a detailed analysis leading to a limit ensuring maximum achievable pollution reduction. Each step of the BACT analysis and especially a decision to reject an effective pollution reduction option in favor of a less effective option when establishing a BACT limit must be adequately explained and justified.

Although the BACT selection process can be complicated, its purpose is simple: to promote the use of the best control technologies. Congress chose to require an emission limit based on the "maximum degree of reduction ... achievable for such source" at the time the source is constructed. 42 U.S.C. §§ 7475(a)(4) (new sources are subject to BACT), 7479(3) (BACT definition). A BACT analysis should always default to the best pollution control option available. Therefore, by design, BACT results in increasingly stringent limits as technology advances and improves the ability to reduce or capture pollutants.

The Draft Permit fails to comply with the requirement that all regulated pollutants be subject to a BACT limit that represents the maximum degree of reduction achievable with available control options. Therefore, the permit must either be denied or the permit limits must be revised, supplemented, and significantly lowered so that the limits represent BACT.

A. The MDEQ Failed To Conduct A BACT Analysis for PM2.5.

The Draft Permit does not include a BACT limit for PM2.5 emissions from the new sources at the Ripley Heating Plant. Nor does it appear that MDEQ even considered such a limit. This is unlawful and must be corrected before a PSD permit can issue. The controlling law requires a BACT limit "for each pollutant subject to regulation under the Act that it would have the potential to emit in significant amounts." 40 C.F.R. § 52.21(j)(2). PM2.5 is "a pollutant subject to regulation under the Act" because EPA established a NAAQS for PM2.5 in 1997. 62 Fed. Reg. 38711; 40 C.F.R. § 50.7. The Court of Appeals rejected industry's collateral attacks of the PM2.5 rule in 2002, upholding the PM2.5 NAAQS. *American Trucking Associations, Inc. v. EPA*, 283 F.3d 355 (D.C. Cir. 2002). Therefore, PM2.5 is a "pollutant subject to regulation under the Act." Moreover, PM2.5 will be emitted from the new and modified emission sources at the Ripley plant in a "significant" amount because it will be emitted at "any emission rate." 40 C.F.R. § 52.21(b)(23)(ii).

Because PM2.5 is regulated pollutant that will be emitted in a significant amount, a BACT limit for PM2.5 is required. 42 U.S.C. § 7475(a)(4); 40 C.F.R. § 52.21(j). Nevertheless, the Draft Permit does not contain a BACT limit for PM2.5 emissions. This is a deficiency that must be corrected before a PSD permit can issue. Additionally, any proposed PM2.5 BACT limit must be subject to public review and comment before KDHE issues a final PSD permit.

The applicant states that "[r]ecent EPA guidance for PM2.5 requires that in the *interim period* between the dates of the PM2.5 NAAQS designations and when EPA promulgates regulations to implement [non attainment area new source review] for the PM2.5 NAAQS, states should use PM10 as the surrogate." Application at 24. The "guidance" referred to is over 10 years old. The guidance memo, itself, estimated 3 to 5 years to implement PSD for PM2.5 and the impracticalities referenced in the memo as the basis for using PM10 as a surrogate (modeling, emission calculations and estimates, etc.) have been largely resolved, as evidenced by EPA's proposal to establish PM2.5 BACT limits. Proposed Rule, 72 Fed. Reg. 54,112 (Sept 12, 2007); see also 70 Fed. Reg. at 66,043 (recognizing that the "practical difficulties" identified in the Seitz memo "have been resolved in most respects."). Moreover, there is simply no legal basis for ignoring the requirement to implement BACT for PM2.5. The EPA's promulgation of PM2.5 NAAQS is premised upon the finding that PM10 and PM2.5 are not equivalent and a PM2.5 standard—rather than merely a PM10 standard-- was necessary to protect health and welfare. That finding cannot be effectively undone, by substituting PM10 through a guidance document, based upon administrative expediency.

Further, PM10 is simply not the same as PM2.5. Controls for PM10 are not necessarily controls for PM2.5 and, more importantly for BACT determinations, top-ranked controls for PM10 are not necessarily top-ranked controls for PM2.5. Common control technologies, such as the fabric filters proposed for the new Ripley plant boiler, are highly effective at controlling PM and PM10, but less effective at capturing finer-grain PM2.5. PM2.5 emissions are more aggressively controlled by controlling the pollutant's precursors. It is therefore necessary to target PM2.5 specifically in a BACT analysis in order to require the greatest feasible reductions in PM2.5 emissions.

B. The Draft Permit Lacks BACT Limits For CO2 and N2O.

The Clean Air Act prohibits the construction of a new major stationary source of air pollutants in areas designated as in attainment of the National Ambient Air Quality

Standards except in accordance with a prevention of significant deterioration (PSD) construction permit. 42 U.S.C. § 7475(a); 40 C.F.R. §52.21(a)(2)(iii). One of the requirements, contained in § 165 of the Act, is that every PSD permit must include a BACT emission limit "for each pollutant subject to regulation under this chapter emitted from, or which results from" the facility. 42 U.S.C. § 7475(a)(4). EPA repeated that requirements in the implementing regulations controlling here: BACT is required for "any pollutant that otherwise is subject to regulation under the Act." 40 C.F.R. § 52.21(b)(50)((iv). Carbon Dioxide (CO2) has been *regulated* under the Clean Air Act since 1993. And, on April 2, 2007, the Supreme Court held that carbon dioxide and other greenhouse gases are "pollutants" under the Clean Air Act—clarifying that they are, indeed, "*subject to* regulation." *Massachusetts v. EPA*, 127 S.Ct. 1438, 1460 (2007).

1. CO2 Is Currently Regulated.

Section 821(a) of the Act provides:

> Monitoring. - The Administrator of the Environmental Protection Agency **shall promulgate regulations** within 18 months after the enactment of the Clean Air Act Amendments of 1990 **to require that all affected sources subject to the Title V of the Clean Air Act shall also monitor carbon dioxide emissions** according to the same timetable as in Sections 511(b) and (c). **The regulations shall require that such data shall be reported to the Administrator**. The provisions of Section 511(e) of Title V of the Clean Air Act shall apply for purposes of this section in the same manner and to the same extent as such provision applies to the monitoring and data referred to in Section 511.

42 U.S.C. 7651k note; Pub.L. 101-549; 104 Stat. 2699 (emphasis added). In short, Congress specifically ordered EPA "to promulgate regulations" requiring that facilities covered by

Title IV of the Act monitor and report their CO_2 emissions in § 821.[1] Further, in section 165 of the Act, Congress required a BACT limit for "any pollutant subject to regulation" under the Act. The Supreme Court has already pointed out that information gathering, record keeping, and data publication rules are indisputably within the conventional understanding of "regulation." *Buckley v. Valeo*, 424 U.S. 1, 66-67 (1976) (record keeping and reporting requirements are regulation of political speech). Therefore, the Act plainly requires a BACT limit for CO_2.

The most basic canon of statutory interpretation is that words should be given their plain meaning, and Webster's defines "regulation" as "an authoritative rule dealing with details or procedure; (b) a rule or order issued by an executive authority or regulatory agency of a government and having the force of law." This plain language is controlling. *Lamie v. United States Tr.*, 540 U.S. 526, 534 (2004); *Chevron v. NRDC*, 467 U.S. 837, 842-843 (1984). As the Court in *Alabama Power Co. v. Costle*, 636 F.2d 323, 403 (D.C. Cir. 1979), held, PSD applies to pollutants in addition to those for which air quality standards or other limits have been promulgated:

> The only administrative task apparently reserved to the Agency . . . is to identify those . . . pollutants subject to regulation under the Act which are thereby comprehended by the statute. The language of the Act does not limit the

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[1] EPA's §821 regulations, which were finalized on January 11, 1993, require CO_2 emissions monitoring (40 CFR §§75.1(b), 75.10(a)(3)); preparing and maintaining monitoring plans (40 CFR §75.33); maintaining records (40 CFR §75.57); and reporting such information to EPA, (40 CFR §§75.60 – 64). 40 CFR §75.5 prohibits operation in violation of these requirements and provides that a violation of any Part 75 requirement is a violation of the Act. These requirements, including the requirement to monitor CO2, are also included in various state implementation plans. *See* Wis. Admin. Code §§ NR 438.03(1)(a) (requiring reporting of pollutants listed in Table I, including CO2), adopted under the Act at 40 C.F.R. § 52.2570(c)(70)(i); NR 439.095(1)(f) (Phase I and phase II acid rain units… shall be monitored for… carbon dioxide…"), adopted under the Act at 40 C.F.R. § 52.2570(c)(73)(i)(I).

> applicability of PSD only to one or several of the pollutants regulated under the Act,
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> . . .the plain language of section 165 . . .in a litany of repetition, provides without qualification that each of its major substantive provisions shall be effective after 7 August 1977 with regard to each pollutant subject to regulation under the Act, or with regard to any "applicable emission standard or standard of performance under" the Act. As if to make the point even more clear, the definition of BACT itself in section 169 applies to each such pollutant. The statutory language leaves no room for limiting the phrase "each pollutant subject to regulation" . . .

The carbon dioxide BACT analysis should consider, inter alia, boiler efficiency, alternate combustion options, and cleaner fuels, including natural gas, biomass, and a blend of biomass and natural gas. The proposed CFB boiler ranks among the least efficient and most polluting boilers possible. More efficient combustion options include gasification of biomass and the burning of biomass gas, instead of a solid fuel. See, for example, the recent announcement by <u>Progress Energy Florida</u> signing another contract with <u>Biomass Gas & Electric LLC</u> (BG&E) to purchase electricity from a second waste-wood biomass plant planned for Florida. BG&E plans to build a power plant in north or central Florida that will use waste wood products – such as yard trimmings, tree bark and wood knots from paper mills – to create electricity. It would generate about 75 MW. The plant will use gasification and projected commercial operation is expected in June 2011.[2]

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[2] http://money.cnn.com/news/newsfeeds/articles/prnewswire/CLTU05618122007-1.htm (last visited 12/24/07).

2. N2O is Currently Regulated.

As noted above for CO2, a BACT limit is required for any pollutant subject to regulation under the Act. The Act includes state implementation plans approved by the EPA. N2O is regulated in at least one State Implementation Plan approved by EPA, and therefore, is not only subject to, but is regulated under the Act. See Wis. Stat. §§ 285.60 (requiring air permits for all sources not otherwise exempted), 285.62(1); Wis. Admin. Code §§ NR 407.05, Table 3 (requiring permit application to include Nitrous Oxides if greater than 2,000 lbs/year). Moreover, nitrous oxide is also regulated under Wis. Admin. Code § NR 438.03(1)(a) and Table 1, adopted under the Act at 40 C.F.R. § 52.2570(c)(70)(i). Therefore, a BACT limit is also required for N2O.

C. The BACT Determinations for the Boiler Did Not Include a Sufficient Analysis of Cleaner Production Processes, Including Wood Fuel.

A BACT analysis for a coal fired power plant must include consideration of cleaner production processes and innovative fuel combustion techniques. The NMU's application attempts to obtain a PSD permit, and BACT limits, for burning coal, while conceding that the boiler can and most likely will burn biomass. Permit to Install Application for Northern Michigan University- Ripley Heating Plant at 1 (February 1, 2007) (hereinafter "Application") (boiler will have the capacity to burn 100% waste wood); Letter from Jeffrey Jaros, NTH, to David Riddle, MDEQ, Re: Addendum to Application No. 60-07 to Update SO2 Emission Limit; Northern Michigan University- Ripley Heating Plant

(September 18, 2007) ("The primary fuel for this boiler will be virgin wood waste.")[3]. In fact, the boiler at issue is "designed to allow operation on Renewable Resources (specifically wood chips) up to 100% of the total heat input..." Letter from Michael Hellman, NMU, to Mary Ann Dolehanty, MDEQ, Re: Permit to Install Application for a New Circulating Fluidized Bed Boiler; Northern Michigan University- Ripley Heating Plant (February 5, 2007). In other words, the boiler is designed for, and can accommodate 100% clean fuel, wood, but NMU is asking for BACT limits based upon coal.

It appears that NMU requests BACT limits based on coal for vague "fuel stability and financial concerns." This is not a sufficient basis for establishing BACT based on the dirtiest fuel—coal—rather than the cleaner fuels that the boiler can burn. Concerns for fuel flexibility and increased cost are not, by themselves, sufficient to justify rejecting clean fuel in a top-down BACT determination. Not every economic consideration justifies rejecting cleaner fuel and, consequently, lower emission limits. Instead, NMU, as the applicant, must demonstrate that the price of using lower-sulfur coal, in dollars per ton of SO2 removed, is not "cost effective," in terms of dollars per ton of pollutant prevented. Therefore, to justify rejecting biomass, such as waste wood, as a pollution control option under BACT, the cost-per-ton of each pollutant removed/prevented must be disproportionate to the cost per ton incurred by other sources. Merely stating a generalized concern about increased costs, fuel availability, or economics, as NMU has done here, is not enough to justify rejecting a method of reducing emissions. Any

[3] It is not clear what virgin wood waste means. It is assumed that the fuel is wood waste—excluding unsustainably managed and/or harvested virgin timber. As noted above, if MDEQ cannot assure this, a thorough review of the collateral impacts from harvesting the wood fuel must be included in the PSD review.

pollution control will cost money. BACT is required by law. Its costs are integral to the overall cost of doing business and are not to be considered an afterthought.

As noted above, NMU bears the burden of demonstrating that 100% waste wood is not cost-effective. Here, because NMU failed to demonstrate that waste wood fuel is not cost effective (indeed it is the planned primary fuel), the BACT analysis must default to that cleaner fuel, not to coal.[4]

1. The BACT Limits Must Be Based On Waste Wood, Not Coal.[5]

As noted above, according to the USEPA and MDEQ top-down BACT procedure, the best or "top" control option should be selected as BACT unless it is shown to be infeasible due to unacceptable economic, environmental or energy impacts.

Waste wood is the intended primary fuel for the new boiler proposed at the Ripley plant, but coal is being approved and is used to establish the BACT limits. The use of coal will generate significantly more SO_2 and carbon dioxide emissions than wood. Unlike wood and other forms of biomass, coal also contains a long laundry list of hazardous metals, including arsenic, mercury and nickel. Because the use of waste wood would result in the lowest emission rates of SO2, the use of 100% waste wood as fuel is the "top" pollution control option. The applicant's application and analyses in support of its permit have not demonstrated, nor can they demonstrate, that this top control option is infeasible.

[4] Note that even if 100% wood were not cost-effective, a mix of wood and coal that maximizes wood must but is still within the range of dollars-per-ton considered cost-effective (i.e., under $10,000/ton) must be assumed in setting BACT limits.

[5] We are not condoning the use of waste wood absent information about the source of the wood, and the environmental impacts, including soil and vegetation impacts, associated with the use of such wood.

The uncontrolled SO_2 emissions while burning waste wood are 0.025 lbs/mmbtu. Letter from J. Jaros - NTH Consultants, Ltd. to D. Riddle - MDEQ, September 18, 2007; *see also* RBLC ID # NC-0092 (woodwaste fired boiler with 0.024 lb SO2/MMBtu BACT limit). The emission rate assumed in the Application and MDEQ's proposed permit is based on a maximum coal sulfur content not exceed 1.5% and a heating value not exceed 12,000 BTU/lbs, or 24 MMbtu/ton. For a CFB boiler, uncontrolled SO_2 emissions occur when no calcium-based sorbents are used and the bed material is inert with respect to sulfur capture. EPA recommends that the emission factor for underfeed stokers should be used to estimate the SO_2 emissions from an uncontrolled CFB boiler. USEPA, *Compilation of Air Pollutant Emission Factors*, Table 1.1-3, Emission Factors for SO_x, NO_x, and CO from Bituminous and Subbituminous Coal Combustion, September 1998. Therefore, the uncontrolled emissions from burning coal at the proposed Ripley plant CFB boiler is:

Coal Factor
= 31(1.5) lbs/ton / 24 MMBtu/ton
= 1.938 lbs/MMBtu

Therefore, the difference in uncontrolled SO_2 emissions when burning coal versus wood is as follows:

Additional SO_2 Emissions from burning coal:
= 185 MMBtu/hr x (1.938 - 0.025) lbs/MMBtu x 8,760 hrs/yr x ton/2,000 lbs
= 1,555 TPY

In other words, if uncontrolled emissions from coal is the baseline, the 100% waste wood option achieves 1,555 tons of SO2 emission reduction per year. This level of SO2 control is cost-effective.

Pollution controls for SO2 are cost effective at $10,000 per ton of air pollutant removed or prevented. Wisconsin Department of Natural Resources, *Analysis and Preliminary Determination for the Construction and Operation Permits for the Proposed Construction of a 650 TPD Preheater Lime Kiln for C L M Corporation-Superior, To Be Located at Hill Ave and Winter St, Superior, Douglas County, Wisconsin*, July 7, 2006; attached as Exhibit A. In order to eliminate the Atop,@ 100% waste wood, control option the NMU would have to demonstrate that the increase in cost, compared to the use of coal, as a secondary fuel exceeds the following level:

Economic Infeasibility Threshold for Use of Wood as Sole Fuel
= 1,555 TPY SO_2 x $10,000 per of pollutant removed
= $15,550,000 per year

Based solely on fuel cost, the difference between waste wood and coal would have to be extreme for NMU to be able to demonstrate that 100% waste wood is infeasible.

Required Difference in Wood and Coal Fuel Costs
= $15,550,000 per year / (205 MMBtu/hr x 8,760 hrs/yr)
= $8.66/MMBtu

As discussed below, the *difference* in fuel cost does not come close to $8.66/MMBtu. Moreover, fuel cost, alone, is not the only cost factor that the NMU would need to consider if it were to attempt to demonstrate that 100% wood is not feasible. Because 100% wood does not necessitate SO2 controls (other than the fuel choice), the facility can avoid the capital and operating costs associated with limestone and the disposal costs of the significant solid waste created by limestone injection. Moreover, an economic feasibility analysis choosing coal over wood must look at the cost effectiveness as to *all* pollutants. Coal will generate hazardous air pollutant emissions not generated by the waste wood including mercury, arsenic, HCl, HF, H_2SO_4 and dioxins/furans. Therefore, the use of wood results in overall pollution decrease much greater than the 1,555 tons SO2/year and would be cost effective even at fuel cost differences *greater than* $8.66/MMBtu.

The difference in cost between wood and coal is not $8.66/MMBtu and, therefore, the use of 100% wood waste is cost-effective, assuming the source of the waste wood does not have unintended environmental impacts, as discussed above.[6] For example, a 2007 Energy Center of Wisconsin report indicates the availability of wood fuel in northern Wisconsin. attached as Exhibit B. Xcel Energy currently burns large amounts of wood waste in its Bay Front Generating Station in Ashland, Wisconsin, and is seeking to convert all boilers to consume 100 percent biomass. *Id.* at 3. The Xcel Bay Front facility is currently paying between $25.00 and $29.00 per ton of wood waste, which provides between 5,500 and 6,500 Btu/pound ($3.85 to $5.27/MMBtu). Conservatively assuming a moderate cost of coal at $1.50/MMbtu and assuming NMU demonstrates that wood waste is available, the difference in cost between 100% wood waste and coal is nowhere close to $8.66/ton. There remain significant questions about the amount of waste wood available in the Upper Peninsula according to a 2000 Northern Initiatives study. This study indicates that waste wood from primary and secondary manufacturing operations is not available in large quantities in the UP.[7]

[6] Again, we are not condoning the use of wood absent information about the source of the wood and the environmental impacts associated with harvesting such wood resources.
[7] http://www.northerninitiatives.com/000511_sam_s_residue_final_report.pdf (last visited 12/24/2007).

- In a top-down BACT analysis, 100% wood waste cannot be rejected as the top-ranked pollution control option. BACT limits must be based upon 100% wood waste.

D. There is No Analysis of Natural gas As a Clean Fuel Option

Natural gas is a fossil fuel, but is significantly cleaner than coal. It contains no sulfur, no mercury and emits a fraction of the carbon dioxide emissions. Natural gas is an available fuel – it is currently the fuel that powers the existing NMU steam boilers. The top-down BACT analysis should consider the use of high-efficiency combined cycle natural-gas fired cogeneration plant or a plant that could co-fire natural gas and biomass gas as an alternative to a CFB boiler. Such a boiler would be more efficient, i.e. less fuel, and would emit a fraction of the emissions.

E. Even If 100% Wood and Natural Gas Could Be Rejected In A Top-Down Analysis, BACT Must Be Established Based On Low Sulfur Coal.

Even if the NMU could demonstrate that it is not economically feasible to burn wood (its planned primary fuel) as a cleaner fuel, the SO2 BACT limit must nevertheless be established based on lower sulfur coal. MDEQ proposes a 0.20 lb/MMBtu limit based on a 24-hour average and a 0.15 lb/MMBtu limit based on a 30-day average, which assumes 92% control of SO2 through the use of limestone in the boiler. *See* Public Participation Documents; Permit Application No. 60-07 at 4 (October 19, 2007). The Application also identifies a 92% removal from limestone in the boiler. Application at 26. However, a 92% removal would result in a limit of 0.11 lb/MMBtu or lower based on low sulfur coal.

Both the Application and MDEQ's review indicate that the NMU proposes to use low sulfur Powder River Basin coal from either We Energies' Presque Isle plant or Marquette Public Utilities' plant. Application at 3; Public Participation Documents at 2. The draft permit limits coal sulfur content to 1.5% by weight, and assumes 12,000 Btu per ton of coal. Draft Permit § 1.3. This equates to approximately 2 lb/MMBtu. However, a review of the EPA's Clean Air Markets web database shows that the PRB coal burned at the Presque Isle plant ranges from 1.12 to 1.30 lb SO2/MMBtu, based on uncontrolled emission rates. Even 1.5 lb/MMBtu is in the high range for PRB coal. *See* EPA Region 7 Comments on Sunflower Holcomb Station Expansion Project for New Units H2, H3, and H4 at 2-3 (November 9, 2006), attached as Exhibit C; USEPA Region 7 letter to the Missouri Department of Natural Resources, Re: City Utilities of Springfield, Southwest Power Station Unit 2, attached as Exhibit D; Letter from JoAnn M. Heiman, Air Permitting and Compliance Branch, U.S. EPA Region 7, to W. Clark Smith, Nebraska Department of Environmental Quality (August 4, 2006), attached as Exhibit E (stating that EPA gathered western subbituminous coal data from a number of sources which "shows the sulfur content (SO2 equivalent) of the PRB-Wyoming coal delivered to coal combustion units in the Region to be on average of 0.74-0.76 lbSO2/MMBtu.").

There is no reason to assume a higher sulfur content coal at the NMU unit, and NMU has not offered any reason. Therefore, even if NMU could demonstrate that 100% coal firing was the only cost-effective option (i.e., wood fuel in any percentage is not cost effective), BACT must still be calculated by applying the 92% control in the boiler to the more realistic coal sulfur content of 0.75 lb/MMBtu typical of PRB coal, and in no case higher than 1.12 to 1.39 lb/MMBtu that is typical of the Presque Isle plant. This would result in a BACT limit of 0.06 lb/MMBtu, and in no case higher than 0.090 to 0.111 lb/MMBtu[8]—much lower than the 0.20 lb/MMBtu limit proposed in the draft permit. 42 U.S.C. § 7479(3) (BACT "means an emission limit based on the maximum degree of reduction of each pollutant... through application of... clean fuels..."). Moreover, as shown below, the plant can achieve a much lower emission rate through the use of additional SO2 controls.

F. NMU Incorrectly Implies That A Proposed BACT Limit That Is "Within The Range" of Previously-Issued BACT Determinations Is Sufficient.

In its application, the NMU suggests that so long as it proposes an emission limit based on the RACT/BACT/LAER Clearinghouse ("RBLC"), no further analysis is necessary in establishing the BACT limit. Application at 36, 42 (proposed SO2 limit is "within the nation-wide range of accepted SO2 emissions that represent BACT"). This is inconsistent with the Clean Air Act and with the purpose of BACT. BACT is technology-forcing and intended to be more stringent with each permit. The RACT/BACT/LAER Clearinghouse is inherently backward looking—consisting only of previously issued permit limits. A proposed limit that is based only upon backward-looking reference to the Clearinghouse, rather than the maximum achievable emission reduction with the most effective combination of pre-combustion and post-combustion controls is not sufficient to satisfy the statutory requirement of BACT. 42 U.S.C. § 7479(3).

[8] The Richardton Plant, a lignite coal boiler in the RBLC has a 0.09 lb SO2/MMBtu BACT limit. RBLC ID # ND-0020.

NMU's assertion appears to be based on informal MDEQ guidance for conducting BACT determinations laid out in Operational Memorandum No. 20, "Best Available Control Technology (BACT) Determinations." (Aug. 24, 2005) This guidance presents a four level process that MDEQ uses to evaluate BACT determinations. However, the guidance is in direct conflict with statutory and regulatory requirements that BACT consist of a case-by-case determination of the maximum degree of reduction achievable at a proposed source, as described above. Only the Level 4 analysis articulates an acceptable BACT process, as it closely follows the U.S. EPA's "top-down" process. Informal agency guidance cannot be used to determine BACT in the face of clear statutory and regulatory requirements delineating a more stringent process and outcome.

G. The Coal-Based-BACT Determination For SO2 Is Inadequate. [9]

There are a number of pollution controls that could be used on the proposed NMU boiler (if coal is assumed as the basis for the BACT limit), that were not sufficiently considered in the applicant's BACT analysis. Scrubbers are common in the electric utility and large industrial boiler sectors and are an "available" as a transfer technology and must be considered in a top-down BACT analysis. An option that is available and results in the greatest emission reduction must be used to establish the BACT emission limit

[9] As noted above, BACT limits for this source should be based upon 100% wood firing, which results in nominal sulfur emissions. The consideration of scrubbing is not necessary for SO2 emissions when wood is presumed in establishing the SO2 limit. This discussion about scrubbing is only provided as background, to the *extent that* MDEQ fails to comply with the BACT process by establishing SO2 BACT based on coal fuel.

unless the applicant can demonstrate that site-specific factors justify rejection of the technology.

Scrubbers are used on CFB boilers following the combustion/limestone process. For example, the Roquette America, Inc., CFB boiler in Iowa uses both limestone injection in the CFB boiler and a post-combustion scrubber. *See* RBLC ID # IA-0083. This allows post-combustion emission control in addition to the reduction achieved in the boiler through the use of limestone. However, the NMU failed to consider (or at least failed to document in the application and the other publicly-available support materials) the combined effectiveness of post-combustion scrubbing in addition to the use of limestone in the boiler.[10] Rather, NMU only compared limestone injection to scrubbing—as if the two controls were mutually exclusive. Application at 40-41.

1. The BACT Analysis Failed To Consider A Circulating Dry Scrubber.

The first step in the top-down BACT analysis is to identify all potentially applicable and available control options. The semi-dry circulating dry scrubber process is a technically and commercially viable scrubber technology. Black & Veatch Corp., *Wisconsin Public Service Weston Unit 4 Flue Gas Desulphurization System Analysis* at p. 2-1

[10] The only indication in the permit record that the applicant considered scrubbing is found in a letter dated September 18, 2007. See Letter from Jeffrey Jaros, NTH, to David Riddle, MDEQ, Re: Addendum to Application No. 60-07 to Update SO2 Emission Limit; Northern Michigan University-Ripley Heating Plant (September 18, 2007). In that letter, NMU's consultant admits that BACT limits have been proposed for CFB boilers based on post-combustion scrubbing. However, the letter asserts, ipse dixit, that vendor guarantees are not likely for lower emission rates than those proposed by NMU. This unsupported assertion is unlikely and irrelevant. Vendor guarantees are neither necessary nor demonstrative of BACT. The relevant question is whether the technology at issue—scrubbers—can achieve a lower emission rate. Moreover, as demonstrated in these comments, scrubbers can and do achieve a 98+% reduction in post-combustion SO2, and are cost-effective for SO2 control.

(March 12, 2003) , attached as Exhibit F; Application of Wisconsin Power & Light Company for a Certificate of Authority to Install SO2 Scrubbers and Baghouses at the Nelson Dewey Generating Station Units 1 and 2, Wis. P.S.C. Docket No. 6680-CE-172, Document # 77419 (June 8, 2007), attached as Exhibit G; Babcock Power, Babcock Power Environmental Adds New Advanced Technology to Reduce Power Plant Emissions (October 3, 2005), attached as Exhibit H; Babcock Power Environmental, Turborsorp (September 29, 2005), attached as Exhibit I; Von Roll, Turbosorp flue gas purification, attached as Exhibit J; Douglas J. Roll, et al., *Comparison of Economic and Technical Features of Fluid Bed and Spray Dryer FGD Systems* (2006), attached as Exhibit K.

Circulating dry scrubbers are widely used in Europe. There are also three installations in the U.S. A circulating dry scrubber is used at the Black Hills Power & Light Neil Simpson 2 plant in Gillett, Wyoming, the Roanoak Valley facility in Virginia, and the Greenridge facility in Pennsylvania. The Neil Simpson plant burns low sulfur western coal from Wyoming— the fuel planned for Holcomb units 2-4-- and achieves 98% SO2 control with a circulating dry scrubber. A circulating dry scrubber is used at the Black Hills Power & Light Neil Simpson 2 plant in Gillett, Wyoming. The plant burns low sulfur western coal from Wyoming and achieves 98% SO2 control with a circulating dry scrubber. Black & Veatch Corp., Conference Memorandum (September 10, 2001), attached as Exhibit R. This is much greater SO2 control than the 92% maximum control efficiency in the boiler that is assumed to be BACT for the Ripley boiler here. One type of circulating dry scrubber, the Turbosorp sold by Babcock Power in the United States, achieves over 95% control of SO2, while controlling mercury and other pollutants, for lower cost than traditional dry scrubber systems. *Id.* This post-combustion control, after 92% reduction in the boiler, would result in an overall 99.6% control. This must be used to establish BACT unless adequately rejected by the applicant in a documented, top-down analysis.

2. A Wet Scrubber Is The Top-Ranked Pollution Control Options for SO2 (If Coal Fuel Is Assumed).

Critical to establishing a BACT limit is determining the top-ranked pollution control. For the proposed Ripley boiler, presuming coal fuel, a wet scrubber is the top-ranked option. After Sierra Club commented on the then-draft permit for the Weston 4 plant in Wisconsin, the consultants for the developer issued a memo acknowledging that they could no longer justify using dry scrubbing as the basis for BACT determinations. The memo stated:

> Currently SO2 emission level limits in Japan are set at 10 ppm, which is available from several wet scrubbing systems. Spray dryers are currently limited to limited periods of operation at outlet SO2 emission of approximately 25 ppm... We believe this situation will be the driving force that will likely eventually push the flue gas de-sulfurization industry to more frequent use of wet scrubbing systems for PRB-fueled projects.

Sulfur Emission Considerations at WPS 006557 (October 19, 2004) (emphasis added), attached as Exhibit M. In other words, the industry recognizes that wet scrubbing can achieve much lower SO2 emissions, even with low sulfur coal, and that once permitting agencies realize this, the industry will be required to use wet scrubbing.

EPA has recognized that new state-of-the art wet scrubbers "have been demonstrated above 98 percent." *Standards of Performance for Electric Generating Units for Which Construction is Commenced After September 18, 1978*, 70 Fed. Reg. 9706, 9711 (Feb. 28, 2005). Even "[e]xisting wet FGD systems ... installed in the past 10 years, are capable of consistently achieving SO2 removal efficiencies of 95 percent and higher." *Id.* at 9715. Multiple plants have demonstrated that 95 percent and higher control is achievable on a long-term basis with a wet scrubber, as opposed to lower SO2 removal efficiencies for existing dry injection systems. *Id.* at 9711. When U.S. EPA recently issued a draft PSD permit for two 750 MW supercritical pulverized coal boilers burning subbituminous coal, it established BACT based on the superior control of a <u>wet</u> scrubber. U.S. EPA, Desert Rock Energy Center (AZP 04-01) Proposed Permit Conditions.

> EPA's independent analysis of available control technologies for pulverized coal fired boilers included reviewing the DOE/NETL (National Energy Technology Laboratory) database, EPA's RACT/BACT/LAER Clearinghouse, EPA's National Coal BACT Workgroup database, and the EPA spreadsheet of recently permitted and proposed coal-fired power plants as well as... other sources...
>
> EPA's review of all available data and technologies demonstrates that the choice of low sulfur coal and wet limestone desulfurization is the most stringent combination of control technologies available for pulverized coal fired boilers. The emission rate of 0.06 lb/MMBtu that [the applicant] has proposed, as a 24-hour average, is lower than other SO2 emission rates that have been proposed for pulverized coal fired boilers recently.
>
> EPA is also persuaded that 0.06 lb/MMBtu SO2 is BACT for [Desert Rock] based on the information in the National Coal Workgroup database...

Desert Rock AAQIR p. 18, attached as Exhibit N.

Certain types of advanced wet scrubbers, particularly a jet bubbling reactor or magnesium enhanced lime scrubber, can achieve 99 percent or greater SO2 removal. Yasuhiko Shimogama, *Commercial Experience of the CT-121 FGD Plant for 700 MW Shinko-Kobe Electric Power Plant*, attached as Exhibit O. A number of facilities have installed the Chiyoda CT-121 jet bubbling reactor. Exhibit P. Chiyoda's bubbling jet reactor (a type of wet FGD) has consistently achieved >99% SO_2 removal during long-term operation at the Shinko-Kobe power plant in Japan. This facility consists of two 700-MW coal-fired utility boilers. The wet FGD was designed to achieve 0.014 lb SO_2/MMBtu (9 ppmv at 3% oxygen) on an instantaneous basis, which is the applicable SO2 emission limit in Japan. It has also been achieved at several coal-fired power plants in Japan and is proposed for several U.S. coal fired power plants. *Id.* Georgia Power recently contracted for the installation of four CT-121 jet bubbling reactors to be installed at Bowen Station. Exhibit Q. Georgia Power expects to achieve 98% reduction of SO2 and 90% reduction of PM with the jet bubbling reactors (in addition to the PM control achieved with the PM control devices). *Id.*

The jet bubbling reactor has been guaranteed by Chiyoda to achieve 99% SO_2 removal on three coal-fired boilers in Japan.[11] It also has been demonstrated in the U.S. at the University of Illinois's Abbott power plant and Georgia Power's Plant Yates[12] and recently was licensed for use on several additional plants in the US, including Dayton

[11] *See* CT-121 FGD Process – Jet Bubbling Reactor, http://www.bwe.dk/fgd-ct121.html.

[12] Emission-control Technologies Continue to Clear the Air, Power, May/June 2002.

Power & Light's Killen and Stuart plants, and AEP's Big Sandy Unit 2, Conesville Unit 4, Cardinal Units 1 and 2, and Kyger Creek, among others.[13] Mitsubishi, a vendor of scrubber systems, reports it has guaranteed SO_2 removal efficiencies up to 99.8 percent, including four coal-fired boilers.[14, 15, 16]

Magnesium Enhanced Lime wet scrubbing technology also achieves SO2 control of 99%. Lewis Benson, et al., *The New Magnesium Enhanced Lime FGD Process* (Exhibit R). Documented experience at the Mitchell Station in Pennsylvania demonstrates that magnesium enhanced lime, a type of wet scrubbing, regularly achieves 99% control of SO2.

In summary, wet scrubbing can achieve 99% control or greater on low sulfur coals. NMU attempts to reject scrubbing—wet and dry scrubbing—based on cost effectiveness. With no supporting documentation and scant discussion, NMU merely asserts that scrubbing would only reduce post-combustion emissions by 40%. September 18, 2007, Letter at 2. Based on this under-estimation of control, NMU asserts that the cost-effectiveness is $15,980 per ton of SO2. *Id.* In addition to applying the cost-effectiveness test wrongly (the entire pollution control train must be included and not each incremental

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[13] Chiyoda Licenses Its Flue Gas Desulfurization Technology in USA Newly for 5 Coal-Fired Generation Units, Press Release, May 2, 2005; Chiyoda Licenses its Flue Gas Desulfurization Process in USA for Georgia Power Owned 4 FGD Units, January 26, 2005.

[14] Jonas S. Klingspor, Kiyoshi Okazoe, Tetsu Ushiku, and George Munson, High Efficiency Double Contact Flow Scrubber for the U.S. FGD Market, Paper No. 135 presented at MEGA Symposium, Air & Waste Management Association, May 19-22, 2003, p.8, Table 4.

[15] Yoshio Nakayama, Tetsu Ushiku, and Takeo Shinoda, Commercial Experience and Actual-Plant-Scale Test Facility of MHI Single Tower FGD.

[16] http://www.mhi.co.jp/mcec/product/fgd.htm.

component), the NMU consultant assumes a very low control efficiency which results in a high cost per ton. If a more reasonable control efficiency of 90-99% is used, the cost per ton drops well below the $10,000/ton threshold most often used for cost-effectiveness determinations.[17] For example, an outlet rate of 0.02 (additional 90% control from scrubber), would result in a cost effectiveness of $7411/ton, using the same assumptions that NMU makes.

Moreover, NMU's incomplete cost analysis for a post-combustion scrubber (a/k/a "polishing scrubber") makes a number of spurious assumptions. First, the attachment to the September 18, 2007, Letter from Jeffrey Jaros, NTH, to David Riddle, MDEQ, assumes an equipment life of 20 years. A properly maintained scrubber lasts for the life of the unit it serves: 30 to 50 years. Second, the analysis assumes 6% for sales tax and 1% for property tax, but presumably, as a public entity, NMU does not pay either tax. Moreover, the taxes, insurance, and administrative charges are calculated as a percentage of total capital, rather than the more common method of estimation based on a percentage of operating labor. Max S. Peters and Klaus D. Timmerhaus, Plant Design and Economics for Chemical Engineers, McGraw-Hill Inc., 4th Ed., 1991, pp. 206-207.

To reject scrubbing (assuming 100% waste wood fuel is also rejected) based on cost, the NMU must provide a comprehensive demonstration, based on objective factors, that the cost of wet scrubbing is disproportionately high and significantly beyond the range of

[17] A recent report by the Lake Michigan Air Directors Consortium ("LADCO") and the Midwest Regional Planning Organization ("MRPO") demonstrates that advanced FGD technologies achieve 99.5% control for $1,240 to $2,875 per ton of SO_2 removed and wet FGD could achieve 99% SO_2 control for $1,881 to $3,440 per ton of SO_2 removed. *See* Exhibit S.

recent costs normally associated with BACT for the type of facility. The NMU has not made this demonstration. Therefore, BACT for SO2 must be based upon 92% sulfur dioxide reduction in the boiler through limestone injection, plus an additional 95+% reduction through the use of a scrubber post-combustion (total 99.6% reduction).

Additionally, to ensure BACT (i.e., maximum degree of reduction), the permit must include either an SO2 removal requirement, or establish different emission limits based on the various inlet concentrations to the scrubber. U.S. EPA has instructed other agencies to do just this. Email from Ethan Chatfield, U.S. EPA, to Rajen Vakharia, Wisconsin Department of Natural Resources (Sept. 5, 2004), attached as Exhibit T; U.S. EPA Comments on PSD Permit for City Utilities of Springfield at 4 (Exhibit U) (requesting that the permit include a 92% control requirement). For example, U.S. EPA instructed the state of Missouri to include either a removal efficiency or a tiered BACT limit to ensure maximum reduction regardless of coal sulfur content:

> [I]n this case, establishing SO2 BACT at 0.12 #SO2/mmBtu effectively allows City Utilities to operate the SDA at an efficiency of 79% when burning PRB coal with an average SO2 inlet concentration of 0.58 #SO2/mmBtu and 87% when burning PRB coal with an average SO2 inlet concentration of 0.93#SO2/mmBtu. These SO2 inlet concentrations correspond to the average and worst case monthly average inlet concentrations for all NSPS Subpart D affected public power units in Region 7 between 1997 and 2002. Both percent reduction efficiencies fall well below the long-term design performance anticipated for the SDA [dry scrubber] as BACT. <u>To compensate for potential under-performance of the SDA when burning lower sulfur PRB coals, we believe the final permit should condition City Utilities to achieve a 92% reduction, based on a 30-day rolling average, in addition to the appropriate BACT emission limit.</u> To assure that the SDA is

> operated in a highly effective manner during all periods of operation, the permit should also require City Utilities to install, operate, maintain, and quality assure inlet SO2 CEMS, in addition to the required stack CEMS, to verify that performance across the SDA is achieved. Since these CEMS are already required by the NSPS Subpart Da, it should not be an imposition to include in the permit. We also concur that any additional need for compliance margin has been accounted for in the analysis for lowering SDA performance from 94 to 92%... and should not be lowered any further.

Ex. U pp. 3-4 (emphasis added). EPA's concerns apply equally in this case. An Administrative Law Judge in Wisconsin held that a static emission limit in the permit for Weston Unit 4 (0.09 lb SO2/MMBtu) did not satisfy BACT. *In the Matter of an Air Pollution Control Construction Permit Issued to Wisconsin Public Service Corporation for the Construction and Operation of a 500 MW Pulverized Coal-Fired Power Plant Known as Weston Unit 4 in Marathon County*, Wisconsin, Case No. IH-04-21 at 9 (Wis. Div. Hrgs. App. Feb. 10, 2006). The ALJ ordered a 90% minimum SO2 removal efficiency be added to the permit to satisfy the requirement of BACT. *Id.* This issue is not being appealed and will be included in the final permit for Weston 4. Similarly, the PSD permit for the Roundup facility in Montana requires 90% control of SO2, as do the permits for Prairie State (98% control) and Indeck – Elwood (92% control) in Illinois. Final PSD Permit for Prairie State Generating Station, No. 189808AAB, p. 16 (April 28, 2005), attached as Exhibit V; Final PSD Permit for Indeck-Elwood LLC, No. 197035AAJ, p. 12 (Oct. 10, 2003), attached as W. The Newmont Mining PSD permit similarly establishes two SO2 BACT limits: 1) 0.09 lb/MMBtu on a 24-hour average when coal sulfur content is greater than or equal to 0.45%; and 2) 0.065 lb/MMBtu on a 24-hour average when the coal sulfur content is less than 0.45% sulfur, combined with a 91% control efficiency. The University of Northern Iowa boiler (Boiler 4) has a BACT limit of 95% reduction. Without a minimum control efficiency included in the permit, the emission controls can under-perform when burning lower sulfur fuels—a result that is inconsistent with the definition of BACT.

H. THE BACT LIMITS SHOULD BE EXPRESSED BY ENERGY OUTPUT.

BACT must be based on the top-ranked pollution control option. Clean production processes must be considered as a pollution control option. 42 U.S.C. § 7479(3); 40 C.F.R. § 52.21(b)(12). As unit efficiency increases, total pollution decreases. *See* U.S. EPA, *Environmental Footprints and Cost of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies* (July 2006). Therefore, BACT must consider efficiency of a unit and total pollution emissions, rather than merely focusing on emissions per unit of energy input. In other words, increased efficiency is a method of pollution control because it decreases the total amount of pollution emitted into the environment to produce electric power.

I. The NOx BACT Limit Is Not Based on Maximum Degree Of Reduction From the Top-Ranked Control Option.

The term "best available control technology" means "an emission limitation based on the maximum degree of reduction of each pollutant …." 42 U.S.C. § 7479(3). The Application contains no evidence that the proposed NOx BACT limit of 0.10 lb/MMBtu is based on the maximum degree of reduction that is achievable. Instead, the Application merely asserts that it is "more stringent than the nation-wide range of NOx emissions that represent BACT for the proposed size boiler, as contained in the RBLC." Application at

43. As noted above, a BACT limit cannot be derived by merely looking at prior determinations. Rather, it must be case-specific, based on the top-ranked pollution control option applicable to the permitted source. The Application fails to analyze Selective Catalytic Reduction as a more-effective control option and fails to justify 0.10 lb/MMBtu as the maximum degree of control from the assumed Selective Non-catalytic Reduction.

1. Selective Catalytic Reduction

The Application discusses selective catalytic reduction (SCR), Application at 42, but bases the proposed BACT limit upon selective non-catalytic reduction (SNCR). Modern SCRs routinely achieve NOx removal efficiencies greater than 90%. Ex. X, pp. 1, 15; Ex. Z, p. 30; Ex. Y, p. 77. Detailed analyses of EPA Clean Air Markets data indicates that "90% removal efficiency is currently being achieved by a significant portion of the coal-fired SCR fleet." Ex. X, p. 15. More than 30 units have achieved greater that 90% NOx reduction. Ex. X, p. 1. Ninety percent NOx removal was achieved on 10,000 MW of coal-fired generation in 2004. Ex. Y, p. 77. Many coal-fired units have been guaranteed to achieve greater than 90% NOx reduction. The McIlvaine reports, one of the sources that should be considered in a BACT analysis, indicate three of Haldor Topsoe's SCR installations averaged over 95% NOx reduction during the 2005 ozone season.

An SCR constitutes the top-ranked pollution control option for the proposed boiler. Conservatively assuming a high boiler outlet NOx rate of 0.4 lb/MMBtu, an SCR can achieve a BACT limit of 0.04 lb/MMBtu. This is much lower than the 0.1 lb/MMBtu limit proposed for the Ripley boiler. Other recent BACT determinations, including Western Farmers Electric Coop and Black Hills Corporation, have established BACT limits based upon SCRs. Nevertheless, with no explanation, the NMU purports to base the proposed NOx BACT limit upon an SNCR. This is a defective BACT analysis and does not result in a limit meeting the definition of BACT. Because NMU has not demonstrated that an SCR is not cost effective, the BACT analysis must default to an SCR.

2. Selective Non-Catalytic Reduction

The NMU does not explain how it derived a 0.1 lb/MMBtu NOx limit through the use of an SNRC. Ag. Processing, Inc., has a BACT limit of 0.08 lb/MMBtu based on an SNCR, as does Cargill, Inc. in Nebraska (RBLC ID # NE-0037). If an SNCR is determined to be the top-ranked control for NOx, the BACT limit for the NMU boiler must be assumed to be *at least* as stringent as these prior BACT limits—and even more stringent based on the maximum achievable control efficiency for an SNCR.

III. THE DRAFT PERMIT DOES NOT CONTAIN ANY BACT CONDITIONS FOR MATERIAL HANDLING

The proposed project will result in increased emissions of PM and PM10 from equipment used to handle, convey, and store materials including coal, limestone, and ash. BACT limits apply to these modified sources. However, the draft permit contains no BACT limits for these sources and it appears that neither the applicant nor MDEQ prepared a BACT analysis for these sources.

Other permits include actual numeric BACT limits for material handling, including:

- 0.004 g/dscf for coal and limestone collectors at the Elm Road, WI
- 0.005 g/dscf for coal and limestone collectors at the MidAmerican, IA
- 0.009 g/dscf for coal collectors at the Wygen 2, WY
- 0.005 g/dscf for baghouses at Indeck-Elwood, IL

Limits on emission rates are feasible for the new and modified material handling processes, as evidenced by the fact that other facilities have emission limits. Moreover, emissions from these material handling processes can be measured either through direct tests of emissions or through emission factors applied to the production rate. Therefore, work practice standards cannot be substituted.

IV. THE DRAFT PERMIT UNLAWFULLY EXCLUDES PERIODS OF STARTUP AND SHUTDOWN.

The draft permit purports to excuse periods of startup and shutdown from the BACT limits. Draft Permit p. 7 § 1.7 ("… permittee shall not operate above any of the applicable maximum operating limits… at all times except during periods of starup, shutdown and malfunction.") This is unlawful for at least three reasons. First, a PSD permit must include stringent requirements to ensure compliance with the Clean Air Act during startup, shutdown and malfunction (SSM). Second, the permit contains no emission limits applicable to the boilers during startup, shutdown or "malfunction." Therefore, the emissions are limited *only by the physical limits of the plant* (i.e., maximum theoretical emissions). This represents the worst-case scenario for emissions. These uncontrolled emissions must be used to model air impacts, but the modeling conducted for the proposed Ripley boiler did not assume these emission rates and, therefore, is deficient. Furthermore, the source should be modeled using the design capacity (100 percent load) and the *least stringent* of the applicable limits. This is why many PSD permits—including the draft Desert Rock permit issued by U.S. EPA-- contain short term limits in addition to limits with longer averaging times and do not exclude startup, shutdown and malfunction. The draft permit for the Ripley plant, however, has no effective limit on emissions during startup, shutdown and malfunction and, therefore, the maximum allowable emissions are equal to the maximum theoretical emissions. In fact, it appears from the application that the maximum theoretical emission rates were not used to model NAAQS and increment consumption. Rather, the modeling submitted presumed short-term limits that are not proposed to be enforceable in the draft permit. This is unlawful. The permit must either contain short-term emission limits that apply at all times, or the permit must be denied unless and until the applicant demonstrates compliance with NAAQS and increment during worst-case, uncontrolled conditions.

Third, there is no definition of "startup," "shutdown," or "malfunction" in the permit. Therefore, because the permit grants a free pass from all emission limits during these periods the permit is unenforceable. There is no way to determine whether a startup, shutdown and/or malfunction is occurring. To the extent that a startup, shutdown and malfunction exemption is allowed (which it is not), the permit must define these periods and require monitoring and reporting sufficient to determine if such condition is occurring at any given moment.

V. THE STARTUP/SHUTDOWN PLAN MUST BE INCORPORATED INTO THE PERMIT AND SUBJECT TO PUBLIC NOTICE AND COMMENT.

The draft permit requires the NMU to "develop, and submit to AQD for review and approval, a written startup, shutdown and malfunction plan (SSMP)." Draft Permit at p. 7 § 1.5. The permittee is required to comply with the plan, once created. *Id.* This post-permit plan development and approval is unlawful. Moreover, the post-permit plan development and approval violates the public notice and comment provisions of the Clean Air Act. .

VI. THE PERMIT MUST ENSURE THAT THE ASSUMPTIONS MADE FOR MODELING ARE ENFORCEABLE.

In addition to the fact that worst-case conditions during startup, shutdown, and malfunction were not modeled, as noted above, there are a number of additional erroneous assumptions made as a part of the modeling for the Ripley plant boiler.

First, the model only included emissions from the new/proposed stack, exhausting the proposed CFB boiler, and the existing stack exhausting the gas boilers. Application at 67. Specifically, the model failed to include the other emission sources, including material handling (coal and solid fuel unloading), cooling towers, diesel generator, silos, limestone crushing, ash handling, and fugitive road dust. These PM/PM10 emission sources are the most likely to result in violations of NAAQS and increment close to the facility, yet were not even included in the model runs by the NMU. This results in a defective permit that does not comply with 40 C.F.R. § 52.21(k).

Second, the Application states that the following emission rates were assumed in the modeling for the plant:

<u>New Boiler</u>

Pollutant	Maximum Hourly Emission Rate (lb/hour)	Modeled Emission Rate
CO	34.85	4.39
SO2	87.80	11.06
PM10	6.15	0.775
NOx	20.50	2.58

Source: Application at 64

<u>Existing Boilers</u>

Pollutant	Maximum Hourly Emission Rate (lb/hour)	Modeled Emission Rate (grams/second)
CO	24.90	3.14
SO2	86.18	10.86
PM10-Increment Rule	4.44	0.56
PM10-NAAQS Rule	4.79	0.60
NOx	10.24	1.29

Source: Application at 66.

These emission rates <u>do not represent worst case</u>, maximum emission rates for several reasons, in addition to the omission of other emission source such as material handling:

> 1. The draft permit exempts periods of startup, shutdown and malfunction, during which there are no enforceable limits on emissions and emissions must be calculated based upon maximum theoretical (uncontrolled) emission rates.
>
> 2. The hourly emission rates used in the model are based upon the draft permit's emission limits, multiplied by the maximum heat input (205 MMBtu/hour). However, the draft permit does not contain hourly limits. Instead, the draft permit proposes limits based upon 24-hour rolling average and 30-day rolling average for SO2, and an unspecified averaging period for PM, PM10, and NOx. During any 24-hour, 30-day, or unspecified averaging

period, the maximum hourly emission rate can be higher (sometimes much higher) than the average, enforceable, emission rate. Unless the emission limits are enforceable maximum hourly rates, they cannot be relied upon to determine maximum hourly emission rates for modeling.

3. The modeling assumed maximum heat input (maximum load). However, maximum modeled impacts are sometimes, if not usually, at reduced load because the stack exit velocity, temperature, and flow rate are lower at reduced load. Multiple scenarios should be run at various reduced loads, including the corresponding reduced stack temperature, velocity, and flow, to determine the highest impact.

In other words, the model is flawed because it assumed that the permit limits apply at all times, including startup, shutdown and malfunction, assumed that the long-term limits are enforceable maximum hourly limits, and assumed that worst-case impacts occur at maximum heat input. All of these flaws should be corrected, the model should be re-run with correct inputs, and the public should be given an opportunity to review and comment on the results.

Additionally, modeling programs are based on emission inputs in grams per second (or other mass-per-time-period increments). However, the emission limits for most emission sources in the permit are expressed in pounds per input, such as pounds per MMBtu heat input. To convert these input-based emission limits into mass-per-time-period units for modeling, the Application assumed a maximum hourly heat input of 205 MMBtu/hour and, therefore, maximum hourly emission rate. The maximum hourly heat input rate is not included in the permit as an enforceable limit.

The permit limits must either be expressed in terms of total mass emissions per hour (i.e., pounds per hour) , or an enforceable hourly heat input limit in addition to mass per heat input must be included in the permit before the permit limits can be relied on for modeling.

VII. THE MODELING APPEARS TO HAVE OMITTED SOME PM10 EMISSIONS.

The NMU application states that not all emissions were considered in the modeling. Although the discussion is vague, the application implies that some emissions from existing boilers were omitted from the model when determining increment consumption. Application at 65. This suggests that, perhaps, the minor source baseline has not been set and, therefore, emissions from existing boilers at the Ripley plant are considered part of the baseline (rather than consuming increment). This should be verified.

VIII. NMU DID NOT CONDUCT THE REQUIRED PRECONSTRUCTION MONITORING.

It does not appear that any preconstruction ambient air monitoring was done for the project. None was provided in response to Sierra Club's request for all records pertaining to the PSD permit. None was included in the application materials submitted by the NMU. From the Application, it appears that NMU used background concentrations provided by MDEQ via email on August 21, 2006. Application at 69. It does not appear, however, that the background concentrations were from source-specific pre-application monitoring for the Ripley Heating Plant site.

As a prerequisite to obtaining a permit to construct, an applicant must provide the Administrator (MDEQ by delegation) with data about the background ambient air quality in the area that will be impacted by emissions from the new EGU. 40 C.F.R. § 52.21(m). This requires the applicant — the NMU-- to install and operate a series of ambient air quality monitors in the area around the proposed facility for at least twelve months prior to submitting its PSD permit application. To use ambient air monitoring data for a period less than twelve months, the NMU must provide sufficient evidence for MDEQ to determine that a complete and adequate analysis can be accomplished with monitoring data gathered over a period shorter than one year--but not less than 4 months. Such decision must be based on a determination that the shorter period provides sufficient air quality data during a time period, or periods, when maximum concentrations can be expected.

As an applicant, the NMU can only avoid collecting site-specific ambient air quality data is if valid, sufficient, and representative ambient air quality data exists from regional monitoring stations. This only occurs in very limited circumstances. In other words, MDEQ must determine, and the EPA Administrator must agree, that data from regional monitoring stations are representative of ambient air quality at the Ripley Heating Plant site. This requires MDEQ to make specific findings on the record. EPA sets forth three criteria for determining when existing ambient monitoring data is sufficient:

1) monitor location;
2) quality of the data; and
3) "currentness" of the data.

No findings were made to justify using existing air quality data, rather than site-specific data, for the Ripley plant permit.

1) Monitor Location

Pursuant to EPA guidance, to use monitoring data from existing ambient air quality monitors to determine baseline air quality for PSD permitting, the data must be representative of three specific areas:

> (1) the location(s) of maximum concentration increase from the proposed source or modification,
>
> (2) the location(s) of the maximum air pollutant concentration from existing sources, and
>
> (3) the location(s) of the maximum impact area, i.e., where the maximum pollutant concentration would hypothetically occur based on the combined effect of exiting sources and the proposed new source or modification.

EPA concludes that existing air quality data is only representative of these three areas when the proposed source will be located in an area that is generally free from existing point source impacts. When the new or modified source will be located in an area that has multiple air pollution sources <u>and flat terrain</u>, the applicant can only use existing, representative monitoring data that is from (1) a nearby monitoring site, <u>within 10 km</u> of the points of emissions; or (2) from a monitor that is no more than <u>1 km</u> away from either the maximum air pollutant concentration from existing sources or from the area(s) of combined maximum impact from existing and proposed sources.

Moreover, even if the existing air quality monitors were located within 10 km of the Ripley plant site, the monitoring data could still not be used. The proposed location of the new boiler is also a "multisource impact area." There are two existing coal-fired plants (Presque Isle and Marquette Board of Light & Power) as well as several mining companies (Empire Iron and Tilden Mining) contributing to air pollution in the area, as well as a number of other area sources. The existence of these sources disqualifies the Ripley plant from using nearby (≤ 10 km) monitor data.

> If the proposed construction will be in an area of multi-source emissions and in an area of complex terrain, aerodynamic downwash complications, or land/water interface situations, existing data could only be used for PSD purposes if it were collected (1) at the modeled location(s) of the maximum air pollution concentration from existing sources, (2) the location(s) of the maximum concentration increase from the proposed construction, and (3) at the location(s) of the maximum impact area. If the monitor is located at only one of the locations mentioned above and the locations do not coincide, the source would have to monitor the other locations.

Id. (emphasis added). In other words, for a site like the Ripley plant, existing ambient air quality monitoring data can only be used if the existing monitors happen to coincide, exactly, with the areas of highest impact from the new facility, the areas of highest impact from stationary sources in the area, and the areas of highest combined impact from both new and existing sources. There is no demonstration in the record that these requirements have been met. Moreover, it is highly unlikely that they can be met by existing monitoring data. In summary, the NMU was required to conduct air quality monitoring for at least twelve months, prior to submitting its PSD permit application to the MDEQ. This was not done and, therefore, the air quality determination is deficient and the permit cannot be issued.

2) Data Quality

Moreover, even if existing air quality monitors could be used to determine ambient air quality for permitting the modified Ripley plant, the data must meet the same quality standards that on-site monitoring must meet. At a minimum, this includes:

1) continuous instrumentation monitoring
2) documented quality control, including calibration, zero and span checks, and control checks;
3) calibration and span gases should be working standards certified by comparison to Nation Bureau of Standards gaseous Standards Reference Material;
4) minimum 80% data recovery

It is not clear that these data quality requirements were met. Again, even if they were, the monitoring locations must still correspond to the requirements above—including location at the points of maximum impact and maximum ambient air concentration.

3) Data "Currentness"

Additionally, if existing ambient air monitoring data could be used to permit the new sources at Ripley, the data must be current. This means that the data must have been collected in the most recent three years (2004-2007). It does not appear that this requirement was met.

Moreover, using data other than site-specific air monitor data violates the Clean Air Act. The plain language of the Clean Air Act requires site-specific air quality monitoring for every PSD permit application. 42 U.S.C. §§ 7475(e)(1) ("The review provided for in [42 U.S.C. § 7475(a)] shall be preceded by an analysis in accordance with regulations of the Administrator… of the ambient air quality at the proposed site and in areas which may be affected by emissions from such facility for each pollutant…" (emphasis added)), 7475(e)(2) (providing that ambient air monitoring "shall include continuous air quality monitoring data gathered for purposes of determining whether emissions from such facility will exceed the maximum allowable increases or the maximum allowable concentration permitted under this part.") Specifically, the plain language of the Clean

Air Act requires that ambient air quality data be collected at and around the site of the new source, and be collected specifically for the purpose of determining whether the source will cause a violation of NAAQS or increment. The Act does not contemplate using ambient air monitoring from a distant location as a surrogate.

IX. THE PSD INCREMENT INVENTORY WAS DEFICIENT.

PSD permit applicants are responsible for conducting modeling to demonstrate that they:

1) do not exceed the increment unless adequate offsets are produced;
2) do not contribute to violations in other states (under CAA § 126);
3) do not adversely impact a Class I area; and
4) do not produce an unacceptable growth associated air pollution impact.

40 C.F.R. § 52.21(k). After the applicant determines the impact area, it must develop emission inventories which are used to perform dispersion modeling for NAAQS and increment analysis. This must include all stationary sources within the region, as well as recently permitted sources that have not yet been constructed. The applicant must also create an increment inventory, which must include data from:

- Increment-consuming sources within the impact area;
- Increment-consuming sources outside the impact area that affect increment consumption in the impact area.
- Building dimensions, stack heights, and other factors necessary to determine downwash from increment consuming facilities.

The applicant must determine whether any major sources have increased emissions since the major source baseline date and whether any source, including minor, area, and traffic sources, has increased emissions since the minor source baseline date.

The Application states that only the new CFB boiler proposed for the Ripley plant and the existing boilers at the Ripley plant increment consuming. Application at 71. The We Energies Presque Isle plant was not modeled as increment consuming. However, because the Presque Isle plant was modified after the major source baseline date, it is not included in the baseline and is "increment consuming." 40 C.F.R. § 52.21(b)(13)(ii). The modeling must be revised to account for the Presque Isle Power Plant's ("PIPP") status as a modified, increment consuming source.

1. The State of Michigan Determined PIPP To Have Been Modified.

On July 10, 2003, the State of Michigan, through the Attorney General representing the MDEQ, filed a motion to intervene in the lawsuit filed by the United States against Wisconsin Electric Power Company ("WEPCO") for violations of the Prevention of Significant Deterioration program of the Clean Air Act. *See* Mot. of State of Michigan Seeking Intervention, *United States v. Wisc. Elec. Power Co.*, Case No. 2:03-cv-00371-CNC, Docket # 18 (E.D. Wis., July 10, 2003). A Complaint by the MDEQ and Michigan Attorney General were allowed on July 21, 2003. *See* Compl. in Intervention of Michael A. Cox, Attorney General of the State of Michigan, ex rel. Michigan Department of Environmental Quality, *United States v. Wisc. Elec. Power Co.*, Case No. 2:03-cv-00371-CNC, Docket # 22 (E.D. Wis., July 21, 2003), attached as Exhibit AA. The MDEQ determined, presumably prior to filing a complaint against WEPCO, that the PIPP underwent one or more major modifications. According to the representations made by MDEQ to the Court:

> In 1999, Wisconsin Electric constructed a modification at an electric generating unit at the Presque Isle Generating

> Station that resulted in a net emission increase over 40 tons per year or more of SO_2 and/or NO_x. Wisconsin Electric constructed the modification without obtaining a PSD permit and without applying best available control technology as required by Section 165(a) of the Clean Air Act, 42 U.S.C. § 7475(a).

Id. ¶ 28.

2. The United States Determined That The PIPP Underwent Major Modifications.

On April 29, 2003, the United States, at the request of the US EPA, filed a civil action against WEPCO for PSD modifications at numerous plants, including PIPP. Compl., *U.S. v. Wisc. Elec. Power Co.*, Case No. 03-cv-00371 (E.D. Wis., April 29, 2003). Before filing this complaint, the US EPA was required to find that WEPCO violated the Clean Air Act. 42 U.S.C. § 7413(a)(1) ("Whenever, on the basis of information available to the Administrator, the Administrator finds that any person has violated or is in violation of any requirement… the Administrator may… bring a civil action…"). Therefore, the filing of the Complaint against WEPCO for PSD violations at PIPP was, necessarily, based on a finding of violation based on information available to US EPA.

Among the information available to the EPA was a memo from George Czerniak, Chief of Air Enforcement and Compliance, EPA Region 5, to Sandra Lee, Office of Regional Counsel, regarding "Potential Major Modifications at Wisconsin Electric Power Company Facilities," dated February 23, 2001, attached as Exhibit BB. In the memo, Mr. Czerniak states that EPA review of documents submitted by WEPCO "shows 16 potential major modifications at five WEPCO power plants." *Id.* One of those projects was the 1999 replacement of reheat tubes on PIPP unit 7. *Id.* at EPA5GEN018775. The project cost

$1,340,585 and resulted in an increase of 184.10 tons of NOx and 226.29 tons of SO2 annually. *Id.* This constitutes a major modification.

3. Based on Information Provided By WEPCO to USEPA and Other Information Available to Sierra Club and MDEQ, PIPP Is A Modified Source.

The PSD program prevents the deterioration of air quality in areas that currently attain the National Ambient Air Quality Standards, by requiring that the construction of any new or modified sources of air pollution is only authorized after a careful evaluation and only when the new or modified pollution source is subject to stringent pollution control limits.[18] *Nat'l Parks Conservation Ass'n v. Tennessee Valley Auth.*, 480 F.3d 410, 412 (6th Cir. 2007). Because Congress anticipated that all sources in existence when it passed the 1977 Clean Air Act Amendments would "fac[e] retirement in 10-15 years," H.Rep. No. 94-1175 at 159 (1976); H.Rep. 95-294 (1977), reprinted in 1977 U.S.C.C.A.N. 1077, 1265, it provided a temporary reprieve by "grandfathering" existing sources. *United States v. S. Indiana Gas and Elec. Co.*, 2002 WL 31427523, *2 (S.D.Ind. 2002) ("When Congress enacted the Clean Air Act in 1970, and subsequently amended it in 1977, it determined that existing pollution sources would be 'grandfathered.'" In other words, existing sources would not be required to immediately install technology to comply with the CAA limitations on pollution emissions.). This reprieve was to be short lived, since Congress provided that sources in existence when the PSD program was enacted would be included

[18] Only the PSD program for attainment areas applies in this case. The Clean Air Act also contains a parallel regulatory scheme for areas where the air quality has not attained EPA's standards ("nonattainment"). 42 U.S.C. §§ 7501-7515. These two programs are referred to as "New Source Review," or "NSR."

with the program when they were modified. *Id.*; *Wis. Elec. Power Co., v. Reilly*, 893 F.2d 901, 909 (7th Cir. 1990) (hereinafter "*WEPCO*") ("But Congress did not permanently exempt existing plants from these [PSD] requirements; section 7411(a)(2) provides that existing plants that have been modified are subject to the Clean Air Act programs at issue here."); *Ala. Power Co. v. Costle*, 636 F.2d 323, 400 (D.C. Cir. 1980); *United States v. Murphy Oil U.S.A., Inc.*, 155 F.Supp.2d, 1117, 1137 (holding that Congress provided 'grandfather' provisions for facilities existing when the 1977 Amendments were passed, "but anticipated that they would incorporate the newly required controls as they underwent modifications or replacement.") (citing *WEPCO*, 893 F.2d at 909)

Therefore, for sources in existence when the PSD program was created, like the PIPP, the PSD program applies when the source undergoes any physical change. 42 U.S.C. §§ 7475(a)(1) (applying requirements to sources "on which construction is commenced"), 7479(2)(C) (defining "construction" to include modifications), 7411(a)(4) (defining modification as "any physical change…"); *S. Indiana Gas*, 2002 WL 31427523, *2 ("'modifications' of existing sources would be required to comply with the New Source Review programs. The CAA defines modification as "any physical change" that increases total emissions.") (internal citation omitted). Specifically, the PSD program applies to every "major modification," which is defined as "any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant…." 40 C.F.R. § 52.21 (b)(2)(i). In other words, a major emitting facility triggers PSD if it: (1) undergoes any physical change; and (2) the change "results in" an increase in air pollution. *WEPCO*, 893 F.2d at 907; *Murphy Oil*, 155 F.Supp.2d at 1137.

The PSD program applies to <u>every</u> physical change, without limitation. *New York v. Envtl. Protection Agency*, 443 F.3d 880, 886 (D.C.Cir. 2006) (holding that Congress applied PSD to every physical change, not merely to "physical changes exceeding a certain magnitude." (citing *Ala. Power*, 636 F.2d at 400)). This includes even "the most trivial activities – the replacement of leaky pipes, for example..." *WEPCO*, 893 F.2d at 905, *id.* at 909 ("any physical change means precisely that."); *see also New York v. EPA*, 443 F.3d 880, 885-87 (D.C. Cir. 2006) (holding that Congress' use of the phrase "any physical change" was intended to apply to the broadest possible category of changes); *New York*, 413 F.3d at 40-42; *United States v. Cinergy Corp.*, 495 F.Supp.2d 892, 901 (S.D. Ind. 2007) ("The CAA defines the term 'modification' broadly as 'any physical change... which increases the amount of any air pollutant emitted...'" (*citing WEPCO*, 893 F.2d at 905; *Ala. Power Co.*, 636 F.2d at 400)). Because this definition, read literally, applies the PSD program to even the replacement of a screw during day-to-day maintenance at a pollution source, EPA adopted regulations which provide that "routine maintenance, repair, and replacement" ("RMRR") activities are exempt from the definition of modification. 40 C.F.R. §§ 51.165(a)(1)(v)(C), 51.166(b)(2)(iii), 52.21(b)(2)(iii); *Sierra Club v. Morgan*, Case No. 07-C-251-S, 2007 WL 3287850 *11 (W.D. Wis. Nov. 7, 2007); *see also* 57 Fed. Reg. 32313, 32316-19 (July 21, 1992) (explaining the need for the RMRR exemption to avoid PSD "encompass[ing] the most mundane activities at an industrial facility (even the repair or replacement of a single leaky pipe, or a change in the way the pipe is utilized."); *WEPCO*, 893 F.2d 901, 905 (7th Cir. 1990) (noting that "the potential reach of these modification provisions is apparent: the most trivial activities- the replacement of leaky pipes, for example- may trigger the modification provisions…"). However, RMRR constitutes an agency's exception from a requirement prescribed by Congress, and, therefore, it can only apply to the very limited category of *de minimus* changes. *Alabama Power*, 636 F.2d at 400; *Ohio Edison*, 276 F.Supp.2d at 855; *In re Tennessee Valley Authority*, 9 E.A.D. at 392-93 (citing *O'Neil v. Barrow County Bd. of Comm'rs*, 980 F.2d 674 (11th Cir. 1993); *North Haven Bd. of Educ. v. Bell*, 456 U.S. 512 (1982)). In fact, because it has the potential to undermine Congress' intent that all sources eventually be subject to the PSD program and stringent pollution limits, the Seventh Circuit has warned that the RMRR exemption cannot be interpreted in such as way as to "open vistas of indefinite immunity from the provisions of … PSD." *WEPCO*, 893 F.2d at 909; *see also Sierra Club*, 2007 WL 3287850, *11; *Ohio Edison*, 276 F.Supp.2d at 855; *In re TVA*, 9 E.A.D. at 410-11 (rejecting an interpretation of RMRR that would "constitute 'perpetual immunity' for existing plants, a result flatly rejected by Congress and the circuit courts in *Alabama Power* and *WEPCO*"). Beginning with the premise that RMRR must be narrowly construed to avoid an unlawful infringement on separations of powers through an agency exception to a statutory requirement, courts have identified three hallmarks of the RMRR exemption:

> First, the exemption applies to a *narrow range of activities*, in keeping with the EPA's limited authority to exempt activities from the CAA. Second, the exemption applies only to activities that are *routine for a generating unit*. The exemption

> does not turn on whether the activity is prevalent within the industry as a whole. Third, *no activity is categorically exempt.* The EPA examines each activity on a case-by-case basis, looking at the nature and extent, purpose, frequency, and cost of activity.

United States v. S. Indiana Gas and Elec. Co., 245 F.Supp. 2d 994, 1008 (S.D. Ind. 2003) (emphasis added) (hereinafter "SIEGCO"). None of the projects at PIPP set forth herein are routine. All were capital projects, costing hundreds of thousands to millions of dollars, and occurring once or twice in the lifetime of each boiler at the PIPP.

The term "net emission increase" is defined as a math formula. 40 C.F.R. § 52.21(b)(3)(i) (1998).[19] Pre-change "actual" emissions are "[i]n general,... the average rate, in tons per year, at which the unit actually emitted the air contaminant during a 2-year period which precedes the particular date and which is representative of normal operations." 40 C.F.R. § 52.21(b)(21)(ii). Because PSD is intended to be a <u>pre</u>-construction program and its application must be determined <u>before</u> commencing a major modification, post-change emissions must be projected as a presumption of future emissions. 57 Fed. Reg. at 32,316-17; 45 Fed. Reg. 52,676, 52,677 (August 7, 1980) (explaining that determination of PSD applicability requires the source to "quantify the amount of the proposed emissions increase.") Post-change emissions for an electric utility steam generating unit, like PIPP, are determined in one of two ways:

1) <u>Actual-to-Projected-Actual.</u> Post-change emissions can be based on a projection of future emissions, called the "representative actual annual emissions," but *only* if the owner of the source conducts additional

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[19] The EPA modified regulations defining emission increases in 2002. These regulatory changes occurred after the modifications to the PIPP. Therefore, the 1996 regulations are cited and relied upon here for changes occurring prior to 2002.

monitoring and "maintains and submits to the Administrator on an annual basis for a period of 5 years from the date the unit resumes regular operation… demonstrating that the physical or operational change did not result in an emissions increase." 40 C.F.R. §§ 52.21(b)(21)(v), (33).

2) Actual-to-potential. If a utility fails to undertake this recordkeeping and annual reporting, it must use an actual-to-potential test, comparing the emissions before the change to the source's post-change "potential to emit," as defined in 40 C.F.R. § 52.21(b)(4). The option to use a "representative actual annual emission" after the change is optional and conditioned on compliance with the monitoring and reporting requirements. 40 C.F.R. § 52.21(b)(21)(v) ("actual emissions… following the physical or operational change shall equal the representative actual emissions of the unit, *provided* the source owner or operator maintains and submits… information demonstrating that the physical or operational change did not result in an emissions increase." (emphasis added)); WEBSTER'S UNABRIDGED DICTIONARY 1556 (2nd Ed., 1998) ("provided" means "on the condition or understanding (that)"; BLACK'S LAW DICTIONARY 1240 (7th Ed.) (same); 72 Fed. Reg. 10447 ("In the 1992 regulation, EPA added a reporting provision… Under the reporting provision, sources that utilize the 'representative actual annual emissions' methodology to determine that they are not subject to NSR must maintain and submit sufficient records…"); *see also* Brief for Resp. Duke Energy Corp, *Envt'l Defense v. Duke Energy Corp.*, Case No. 05-848 (U.S.S.Ct., Sept. 15, 2006) (acknowledging, on behalf of the utility industry, that the "projected actual," or "representative actual" post-change emissions test is "an *optional* test for electric utilities, and the 1980 Rules [providing an actual-to-potential test] remained the default," and that the 1992 WEPCO Rule actual-to-projected-actual test "is available *only* to utilities that satisfy certain post-project reporting requirements…" (emphasis original)).

Because WEPCO failed to comply with the monitoring and reporting requirements precedent to use the actual-to-projected-actual test, the actual-to-potential test applies. Each of the projects below results in a significant increase under the actual-to-potential test. However, as set forth below, PIPP underwent several physical changes that resulted in significant net emission increases under both the actual-to-potential test and the actual-to-projected actual (representative actual) test.

According to WEPCO's statements, under oath pursuant to CAA § 114, the following projects (among others) were undertaken at PIPP:

- A project in 1987-1988 to replace and upgrade the coal handling system (cost: ~$2,049,541)
- July 1989 replacement of the forced draft fan on boiler 2 (cost: 655,858)
- October 1992 replacement of a reheat section on boiler 6 (cost: $296,672)
- March 1993 replacement of a reheat section on boiler 5 (cost: $256,422) and economizer tubes on boiler 4 (cost: $260,277)
- March 1994 replacement of superheater wrapper tubes on boiler 5 (cost $321,320) and boiler 6 ($330,292)
- March 1997 replacement of superheater tubes on boiler 4 (cost: $1,091,572)
- May 1998 replacement of reheat tubes on boiler 7 (cost: $1,340,585) and boiler 6 (cost: $1,319,450)
- October 1998 repair of generator winding on unit 1 (cost $1,704,021)
- January 1999 replacement of a waterwall in boiler 3 (cost: $545,075)
- June 1999 overhaul of the unit 3 turbine (cost: $1,666,652)
- September 2000 replacement of a waterwall on boiler 2 (cost: $459,376)
- March 1998 upgrade to the unit 1 high pressure turbine (cost: $5,524,076)
- August 1998 replacement/upgrade of boiler 1 economizer (cost: $447,787)
- January 1999 project to allow ash reburn (cost: $3,092,422)
- April/May 1999 partial rewind of unit 1 generator (cost $1,676,949) and replacement of the boiler 1 superheater (cost: $5,421,036)

Exhibit CC. Each of these projects resulted in a significant net emission increase under the actual-to-potential test. An in-depth analysis of projects at units 3, 7 and 8 also shows increases under the actual-to-projected actual test. Fox Rpt. 71-103, attached at Exhibit

DD. Specifically, Sierra Club's expert reviewed the relevant documents and made the following conclusions, as documented in the attached declaration and report:

- The 1999 project to replace 75% of waterwall tubes on PIPP 3 was not RMRR and resulted in an increase of at least 42 tons of SO2 annually (Fox Rpt. 72-83).
- The replacement of high temperature and low temperature superheaters on PIPP 7 and 8 were not RMRR and resulted in increase of at least 51 tons of NOx and 94 tons of SO2 annual for Unit 7 and 47 tons of NOx and 90 tons of SO2 annually for SO2 (Fox Rpt. 84-103).[20]

For these reasons the PIPP has been modified since the major source baseline date and cannot be assumed to be in the baseline. The modeling for increment consumption must be redone and the PIPP must be modeled as consuming increment. The applicant, NMU, has not demonstrated that the proposed project at the Ripley plant complies with 40 C.F.R. § 52.21(k)(2) (maximum allowable increase) when PIPP is included as consuming increment. Unless and until the applicant makes such showing, no permit can issue.

X. THE SIGNIFICANT IMPACT LEVEL MUST BE REASSESSED WHEN ALL EMISSIONS ARE INCLUDED.

As noted above, the air modeling looked only at stack emissions from the boilers at the Ripley plant. <u>It did not include fugitive emissions, cooling tower emissions, or emissions from material handling</u>. Application at 63-64. Based on this truncated modeling, the NMU predicted no off-site impacts of PM/PM10 greater than the

[20] The emission increases were calculated for two separate reasons — increase in generation and increased utilization. The emissions set forth here are for the small of the two increases. Either basis for calculating the increase results in significant increases. Fox Rpt. 97, 101. The cumulative increase is even greater. Fox Rpt. 102.

Significant Impact Level in any Class II area. Application at 74-75. Because emissions from the fugitive sources and material handling sources will affect the SIL modeling, the modeling should be redone to include all sources. If, as is very likely based on the configuration of the sources, the emission rates, and the likely dispersion, the complete model shows Class II area impacts greater than the SIL, full modeling should be done.

XI. THE APPLICATION ILLEGALLY USES SIGNIFICANT IMPACT LEVELS TO AVOID ANALYSIS OF CLASS I IMPACTS.

The proposed boiler is relatively close to a Class I area. The NMU used Significant Impact Levels ("SILs") to determine whether analysis of impacts should be considered for both Class I and Class II areas. Application at 56, 70. However, there is no legal basis to truncate air impact analyses for Class I areas based on SILs.[21] The NMU has failed to demonstrate that the source will not cause an exceedance of increment, as required by 40 C.F.R. § 52.21(k). The permit cannot be issued.

Moreover, even for SO2, which modeled over the SO2 SIL, the application does not discuss or disclose the amount of increment consumption in the Class I area that is only 50 km away. This must be corrected and the public must be given an opportunity to review and submit comments on the analysis.

[21] In a proposed rule, EPA considered promulgating significant impact levels to determine whether a source will contribute to a violation of a Class I increment. *See* 61 Fed. Reg. 38,249, 38,291-92 (July 23, 1996). However, this proposed regulation was never finalized and, therefore, there are no Class I SILs.

XII. THERE IS NO INDICATION THAT NOTICE OF CLASS I IMPACTS WAS PROVIDED TO THE FEDERAL LAND MANAGER OR THE PUBLIC.

40 C.F.R. §§ 52.21(p) and 124.42 require notice to be given to the Federal Land Manger ("FLM") of an application and any preliminary determination for any source that could affected a Class I area. Although there is at least one nearby Class I area, there is no record that the FLM was given notice. Additionally, 40 C.F.R. § 52.21(q) provides that DEP "shall follow the procedures at 40 CFR 52.21(r) as in effect on June 19, 1979[.]" 40 CFR 52.21(r) as in effect on June 19, 1979 requires that MDEQ "notify the public . . . of . . . the degree of increment consumption that is expected from the source[.]" 43 Fed. Reg. 26388, 26409 (June 19, 1978). While the Public Notice for the draft permit identified that 66% of SO2 increment would be consumed, it neither specified which SO2 increment (Class II 24-hour, not annual or 3-hour), nor the amount of Class I increment that would be consumed. The amount of impact on increments is important to the public. The MDEQ must re-notice the permit, include the amount of increment consumption for all applicable increment standards, and take new public comment.

XIII. THE PERMIT MUST CONTAIN A REQUIREMENT THAT THE APPLICANT OBTAIN A NEW BACT AND MODELING ANALYSIS FOR ANY EMISSION SOURCE THAT DOES NOT COMMENCE CONSTRUCTION WITHIN 18 MONTHS.

The Draft Permit purports to require a new BACT determination and modeling analysis for any unit that does not commence construction within 18 months. See Draft Permit, General Provision 2. This requirement must clarify that a new BACT determination and modeling analysis must be obtained for any emission source that does not commence construction within 18 months. As written, the provision could be misinterpreted to require a new BACT and modeling analysis only for the main boiler units, rather than any emission source that does not commence construction within the requisite time period. Furthermore, the permit, itself, must expire if the source does not commence construction within 18 months.

XIV. THE APPLICATION ERRONEOUSLY LOOKS AT ONLY THE RIPLEY PLANT EMISSIONS TO DETERMINE MAJOR HAP SOURCE STATUS.

The Application concludes that NMU is not a major source of Hazardous Air Pollutants (HAPs) because "the maximum potential HAP emissions for NMU (new boiler plus existing boilers) will be 23.4 tons per year." Application at 18. In other words, the application looks only at the heating plant, and not the NMU campus as the "source." Clean Air Act § 112, 42 U.S.C. § 7412, applies not only to the heating plant, but also to the entire "group of stationary sources located within a continuous area and under common control." 42 U.S.C. § 7412(a)(1). The campus, as a whole, is the "source." NMU and

MDEQ must determine if the campus, as a whole, has the potential to emit more than 10 tons of a single HAP, or 25 tons of all HAPs, per year.

XV. THE APPLICATION INCORRECTLY STATES THAT CAM DOES NOT APPLY.

The Application argues that the Continuous Assurance Monitoring Rule (CAM) does not apply because CAM does not apply to NSPS limits. Application at 19. However, the permit limits in the draft permit are based on BACT, not NSPS. Therefore, the exception from the CAM rule in 40 C.F.R. § 64.2(b)(1)(i) does not apply. CAM is required for all emissions that will be controlled with a pollution control device and for which no continuous monitors are used.

XVI. FAILURE TO CONSULT RE: ENDANGERED SPECIES

PSD permits are actions subject to the section 7 endangered species act consultation requirements. We could not locate any information in the record indicating that EPA and MDEQ had satisfied EPA's ESA consultation obligations. Consultation must be conducted and its results made available to the public prior to the close of the comment period, particularly if the consultation involves consideration of endangered plant species. Any consultation must consider endangered species that may be impacted by the proposed source, as well as the areas impacted by the proposed fuel source.

CONCLUSION

For the foregoing reasons, Petitioner Sierra Club respectfully requests that the permit be denied until significant additional analyses and modifications are made, and the public has had another opportunity to review and comment on a revised draft permit. Thank you for considering these comments.

GARVEY MCNEIL & MCGILLIVRAY, S.C.

David C. Bender
634 W. Main Street, Suite 101
Madison, WI 53703
Phone: (608) 256-1003
Fax: (608) 256-0933
bender@gmmattorneys.com

SIERRA CLUB
Bruce E. Nilles, Director
National Coal Campaign
122 W. Washington Avenue, Ste 830
Madison, WI 53703-2200
Phone: (608) 257-4994
Fax: (608) 257-3513
bruce.nilles@sierraclub.org

CC: EPA Region 5 Administrator Mary Gade (w/o attachments)
NMU President Leslie Wong (w/o attachments)