January 23, 2019

Via e-mail to DEQ-AQD-PTIPublicComments@michigan.gov
Ms. Annette Switzer
Permit Section Manager
Michigan Department of Environmental Quality
Air Quality Division
Lansing, Michigan 48909-7760

RE: Comments on the Draft Permit to Install (Permit No. 128-18) Proposed for L'Anse Warden Electric Company, LLC (LWEC) by the Michigan Department of Environmental Quality (MDEQ).

Dear Ms. Switzer:

Environmental Integrity Project, on behalf of itself, Friends of the Land of Keweenaw (FOLK), and Partnership for Policy Integrity, hereby submits these comments on the draft Permit to Install (PTI) (No. 128-18) for L'Anse Warden Electric Company, LLC (LWEC) at 157 South Main Street in L'Anse, Michigan (Baraga County). LWEC operates a 324 MMBtu/hr boiler to produce steam and electricity by burning a combination of fuels including natural gas, wood chips, tire derived fuel (TDF), railroad ties, wood fines, and bark. The draft PTI would authorize LWEC to burn up to 50,000 tons per year (tpy) of engineered fuel pellets consisting of 30 to 40% plastic and 60 to 70% fiber/paper material. The draft PTI additionally requires LWEC to operate a dry sorbent injection (DSI) pollution control device when the facility burns pellets. Although the addition of the DSI control technology is welcome, the draft PTI is flawed in several significant ways and must be amended before MDEQ issues the permit to LWEC. Most significantly, LWEC has improperly calculated that the project will be a minor modification despite stack tests showing that the project will in fact constitute a major modification due to an increase in nitrogen oxide (NOx) emissions of more than 50 tons per year. Additionally, the draft PTI continues to classify the facility as an area source (i.e. minor source) of hazardous air pollutants (HAPs) despite considerable evidence that aggregate HAP emissions exceed the major source threshold. Finally, the PTI improperly relaxes or eliminates previously-established limits on hydrogen chloride emissions from the boiler and particulate emissions from the sorbent storage silo. MDEQ must address these and other issues identified below before issuing the PTI to LWEC.

I. The Pellet Modification is a Major Modification Subject to Major New Source Review.

LWEC is a major source of air pollution under the New Source Review provisions of the Clean Air Act.[1] Therefore, any modification of the facility that results in an increase in emissions greater than the significance threshold for a given pollutant is a major modification subject to the pre-construction review provisions of the Clean Air Act. Specifically, any major modification to the LWEC plant must comply with the Prevention of Significant Deterioration (PSD) requirements set forth in Part C of Title I of the Act, which have been incorporated into Michigan's federally enforceable State Implementation Plan at Part 18, R 336.2801, *et seq*. Among other things, the PSD program requires that the facility reduce emissions to the level achievable using Best Available Control Technology (BACT).

In order to determine whether this modification will cause a significant increase in emissions, LWEC utilizes the "actual-to-projected-actual" test, comparing actual emissions from a baseline period before the modification to projected actual emissions during the five year period after the modification.[2] Using the actual-to-projected-actual method, LWEC estimates that this modification will result in most pollutants decreasing, while NOx is projected to increase just 3.86 tpy.[3] The significance threshold for NOx is 40 tpy, meaning that if LWEC's estimates are correct, the project is not a major modification. Unfortunately, LWEC has significantly overestimated its baseline actual emissions, meaning it has undercounted the true increase in NOx emissions substantially. Using the correct baseline actual emissions, this modification will result in an increase in NOx emissions of at least 53 tpy, and is therefore subject to PSD review, including the requirement to reduce emissions to the level achievable using BACT.

A. LWEC Incorrectly Calculates Baseline NOx Emissions.

To calculate baseline NOx emissions, LWEC has selected the two-year period between May 2013 and April 2015, which the company states "includes the highest heat input during the last 10 years."[4] Next, LWEC explains that "stack testing was used to develop MAERS [Michigan Air Emissions Reporting System] emission factors and those factors were applied to the baseline period."[5] Bizarrely, for NOx, LWEC uses the same emission factor (0.244 lb/MMBtu) for the 2013-2015 baseline period as it does for the projected actual emissions after the modification (estimating that its baseline emissions were 279.42 tpy and its projected actual emissions will be 283.29 tpy).[6] The 0.244 lb/MMBtu emission factor is from the 2017-18 stack tests conducted while firing the engineered fuel pellets that LWEC is now seeking approval to utilize.[7] This is plainly inappropriate, as the entire point of the 2017 and 2018 pellet testing was to establish how utilizing engineered fuel pellets would change the facility's emissions.

[1] LWEC Application for PTI No. 128-18, at 1 (July 3, 2018) (Hereafter "July 2018 Application").
[2] *Id.* at 13.
[3] *Id.*, Table 5.
[4] *Id.* at 13.
[5] *Id.*
[6] *Id.*, Table 5.
[7] *Id.*

To accurately determine the NOx emission increase that will result from utilizing engineered wood pellets, LWEC and MDEQ should instead use an emission factor from testing conducted in 2015, which is far more representative of the emissions from the baseline period (in fact, we know of no other NOx tests conducted at the facility between 2010 and 2017).[8] The emission factor from the 2015 test is 0.201 lb/MMBtu, which is nearly 20% lower than the emission factor proposed by LWEC from the pellet tests.[9]

The difference in emission factor is critical—using the rate directly from the contemporaneous 2015 stack tests, the baseline NOx emissions are 230.1 tpy, not 279.42 tpy as LWEC claims.[10] The proposed modification, therefore, results in an increase of at least 53.2 tpy.[11] That rate plainly exceeds the 40 tpy threshold for a major modification.

The basis for using anything other than the 2015 emission factor is absent from the permit record. Neither LWEC nor MDEQ explain how stack testing was "used to develop MAERS emission factors" for the baseline period, nor provide any explanation for why it would be acceptable to use anything other than the rate given directly by the 2015 stack test. At a bare minimum, this failure to provide justification for the emission factor is itself a defect that renders the draft permit deficient.[12]

B. MDEQ Must Conduct a PSD Review and Establish Best Available Control Technology (BACT) Emission Limits.

As demonstrated above, the addition of engineered fuel pellets is a major modification requiring a full PSD review, including the implementation of BACT limits for NOx. While the PSD analysis and BACT determination must be subject to additional public notice and an opportunity

---

[8] To our knowledge, no testing for NOx occurred between 2010 and 2017 other than the September 2015 testing and the December 2017 tests conducted while burning pellets. A FOIA request for all stack tests conducted between 2010 and 2015 produced only the September 2015 test and testing for HCL testing from 2011. We do note that testing for NOx was conducted in 2009, and reported an even lower emission factor of 0.18 lb/MMBtu, which would equate to 206 tpy of actual emissions during the baseline period. That rate, in turn, would mean this modification results in an increase of 77 tpy of NOx.

[9] L'Anse Warden Electric Company Boiler Number One, Emissions Test Report (Nov. 2015), tests conducted Sep. 24, 2015. The test reported an emission rate of 65.1 lb/hr for NOx; to produce an emission factor, we divide 65.1 lb/hr by the heat input rate of 324 MMBtu/hr, which is the nameplate capacity of the boiler. The test report does not actually report the heat input during the testing, but based on the emission rates given for PM during the same test, which are listed in terms of both lb/hr and lb/MMBtu, we back-calculate a heating value of 325 MMBtu/hr, confirming that the facility did operate at or very near its nameplate capacity of 324 MMBtu/hr during the 2015 testing.

[10] We accept LWEC's baseline period heat input rate of 2,290,367 MMBtu/yr, and therefore calculate baseline NOx emissions as such: (2,290,367 MMBtu/yr)*(0.201 lb/MMBtu)/(2000 lb/ton) = 230.10 tpy.

[11] We note that the increase may actually be somewhat higher because the 2017-2018 tests that LWEC relies upon to estimate post-project emissions were conducted while the "boiler load was maintained at 90% of capacity" during each of the tests and therefore may not represent emissions at full capacity. *See, e.g.* LWEC Boiler Number One Pellet Trials Test Program Emissions Test Report, at 7 (Feb. 2018).

[12] *See* Mich. Admin. Code R 336.1207(1)(d), requiring that the DAQ "shall deny an application for a permit to install if . . . sufficient information has not been submitted by the applicant to enable the department to make reasonable judgments" as to whether the facility will violate applicable requirements of the Clean Air Act.

to comment,[13] we discuss briefly here the existing control technology that MDEQ must, at a minimum, select as BACT.

As EPA has explained, a BACT determination must implement the "most stringent emissions limits achieved in practice at similar facilities," unless the facility can demonstrate that the control technology is not feasible or should be rejected due to specific collateral impact concerns.[14] The specific collateral impact exception is narrow, and EPA has explained that consideration of collateral impacts "operates primarily as a safety valve whenever unusual circumstances specific to the facility make it appropriate to use less than the most effective technology."[15] If a permitting authority proposes limits which are less stringent than those for similar recently permitted facilities, the burden rests with the applicant and the agency to justify and explain why those more stringent limits were rejected.[16]

In terms of LWEC, it's clear that NOx-reducing technology is both available and feasible. Numerous, if not most, comparable biomass-burning power plants have installed or are required by permit to install NOx control technology that achieves significant reductions in NOx emissions, including the use of selective catalytic reduction (SCR) and selective noncatalytic reduction (SNCR).[17] In fact, based on a survey of recent permits for similar biomass plants, it appears that such controls are exceedingly common.[18] Many of these permits have implemented NOx limits lower than 0.1 lb/MMBtu, vastly lower than LWEC's current allowable emissions (the equivalent of 0.448 lb/MMBtu), and we see no reason why LWEC could not achieve that rate or lower with the use of SCR or SNCR control technology.[19] To provide just one example, a biomass boiler in New Hampshire with a gross output of 18.8 MW—on par with LWEC's nameplate capacity of 22 MW—achieves an emission rate of 0.064 lb/MMBtu through the use of SCR.[20]

C. LWEC's Application and the Draft Permit Suffer From Several Additional New Source Review Issues.

In addition to the fact that this project is a major modification for NOx, as discussed above, LWEC's application is ambiguous or defective in several additional ways that render LWEC's New Source Review determination (and therefore the draft permit) insufficient. First, LWEC has failed to support its calculations for volatile organic compound (VOC) and carbon monoxide (CO) emissions, and second, LWEC has not provided adequate information concerning anticipated heat input rates during the five year period after the modification.

---

[13] Mich. Admin. Code R 336.2817; *see also* 40 CFR 51.166(q), requiring public participation in permits authorizing major modifications.
[14] *In re Knauf Fiber Glass, GMBH*, 8 E.A.D. 121, 131-32 (E.A.B. Feb. 4, 1999).
[15] *Id.* at 131, *quoting In re Columbia Gulf Transmission Co.,* 2 E.A.D. 824, 827 (E.A.B. June 21, 1989).
[16] *In re Knauf Fiber Glass*, *supra* note 14, at 131.
[17] Booth, Mary S., "Trees, Trash, and Toxics: How Biomass Energy Has Become the New Coal," Partnership for Policy Integrity (Apr. 2, 2014), at 32, *available at*: https://www.pfpi.net/wp-content/uploads/2014/04/PFPI-Biomass-is-the-New-Coal-April-2-2014.pdf. (Attachment A).
[18] *Id.*
[19] *Id*.
[20] New Hampshire Department of Environmental Services, Permit Application Review Summary for DG Whitefield, LLC (Jan. 22, 2018), at 4 (citing to stack test results). (Attachment B).

1. It's Unclear How LWEC Estimates a Decrease Rather Than an Increase in VOC Emissions.

LWEC calculates that under the proposed modifications, VOC emissions will be reduced from 50.96 tpy to just 0.93 tpy.[21] The permit record, however, is completely devoid of any information on how LWEC estimates such a decrease. Notably, LWEC did not test for VOC emissions during the 2017 and 2018 stack tests conducted while firing pellets. Instead, to estimate post-project emissions, LWEC cites to 2015 testing without further explanation.[22] Using a test from before the pellet testing period to calculate emissions after the pellet modification is plainly unacceptable.

There's reason to believe introducing plastic pellets into LWEC's fuel mix could increase VOC emissions significantly. In a survey of emissions from seven waste incinerators, researchers noted that "[h]igh [VOC] emissions occurred in two plants when the moisture and plastic contents of the refuse were high."[23] At a bare minimum, LWEC and MDEQ must provide additional information to support the claim that adding plastic-laden fuel pellets to the fuel mix will not result in an increase in VOC emissions beyond the significance threshold. Further, if LWEC and/or MDEQ believe that operation of the DSI system will somehow decrease VOC emissions, the expected control efficiency must be quantified and explained as part of estimating post-project emissions.[24]

Finally, MDEQ should require LWEC to conduct VOC tests while combusting pellets prior to issuance of the permit, or at least revise the draft permit to include a requirement to conduct VOC testing as promptly as possible after issuance. Currently, the only requirement to test the boiler for VOC emissions is the requirement to conduct a test "at least once every five years."[25] Further, the testing requirement does not specify that the plant shall combust pellets during the test, meaning those tests, whenever they occur, may not represent VOC emissions from combusting pellets.[26]

2. The Carbon Monoxide (CO) Calculations Appear Deficient.

According to its application, LWEC calculated baseline CO emissions using an emission factor from MAERS.[27] It's unclear why LWEC does not simply use the actual continuous emissions monitoring system (CEMS) data from the baseline period rather than an emission factor of uncertain provenance. The CEMS data should be the best available data on actual emissions during the baseline period, and we see no reason to use any other data. At the very least, MDEQ

[21] July 2018 Application, Table 5.
[22] *Id.*
[23] Zhang, X. J., "Emissions of Volatile Organic Compounds from Large-Scale Incineration Plants," Journal of Environmental Science and Health, Part A, Vol. 33, Issue 2 (1998), *available at*: https://www.tandfonline.com/doi/abs/10.1080/10934529809376732. (Abstract is included here as Attachment C).
[24] We note that a review of available literature on DSI systems reveals no information on VOC control efficiency provided by DSI.
[25] Draft Permit at 9.
[26] *Id.*
[27] July 2018 Application, Table 5.

should review the CEMS data from the baseline period to verify that LWEC's calculations are correct.

3. LWEC Must Clarify and Supplement its Projected Heat Input for the Five-Year Post-Construction Period.

In order to estimate post-project actual emissions, LWEC relies on a "projected heat input developed from the plant's business plan for 2019 through 2024."[28] LWEC further states that "[t]he highest annual heat input was identified for January 2019 through December 2019 (Calendar year 2019) and was used to make projections."[29] There are several issues with these statements. First, notwithstanding that it is already 2019 and the project has not been completed let alone permitted, calendar year 2019 does not seem to actually be the 12-month period with the highest heat input according Table 7 of the application. Table 7 lists the projected heat input for each month from January 2019 through December 2023, and shows that calendar year 2019 (at 2,313,702 MMBtu/yr) is actually the lowest heat input period, with the 12-month rolling total heat input increasing each month until December 2020 (2,322,039 MMBtu/yr), at which point the yearly heat input remains steady thereafter. Further, the application states in Table 5 that "LWEC has estimated that input to the boiler from January through December 2019, is estimated at 2,448,885 MMBtu," which is even higher than the rates given in Table 7.[30] Ultimately, LWEC does use the highest heat input from Table 7 to calculate projected emissions, which is appropriate as long as that rate is indeed the maximum projected heat input LWEC anticipates operating at. Given the contradictions, however, MDEQ should verify that LWEC does not have plans to operate at higher heat inputs (such as the 2,448,885 MMBtu rate given with Table 5). If LWEC does intend to operate at higher heat inputs, it must revise the potential actual emissions from the post-project period accordingly.

Finally, LWEC has only provided heat input projections through December 2023, which is now less than five years of data. MDEQ must therefore require LWEC to provide additional projected heat input rates for the year 2024 and potentially beyond in order to confirm that no 12-month period in the five years after the project is complete has higher projected actual emissions.

II. MDEQ Has Failed to Conduct an Adequate Hazardous Air Pollutant (HAP) Analysis and LWEC is Likely a Major Source Rather than an Area Source.

MDEQ currently considers LWEC to be an area source, i.e. minor source, of HAPs subject to 40 CFR Part 63 Subpart JJJJJJ, National Emission Standards for Hazardous Air Pollutants (NESHAP) for Industrial, Commercial, and Institutional Boilers Area Sources. In order to be an considered an area source, LWEC's potential to emit (PTE) for any given HAP must be below 10 tpy, and its PTE for aggregate HAPs must be below 25 tpy. If LWEC's PTE exceeds either or both of those thresholds, LWEC would be subject to major source NESHAP standards under 40 CFR Part 63, Subpart DDDDD.

---

[28] *Id.* at 13.
[29] *Id.*
[30] *Id.*, Table 5.

As explained below, LWEC and MDEQ have not conducted a proper analysis for HAP emissions while combusting pellets to determine whether the facility will be a major source. Moreover, we demonstrate that it is highly likely the facility has been a major source since switching from natural gas in 2007, and that the facility will continue to be a major source after this modification.

A. LWEC's Failure to Analyze Aggregate HAP Emissions Renders the Draft Permit Unlawful.

Neither LWEC nor MDEQ appear to have conducted a comprehensive accounting of HAP emissions to demonstrate that this modification will not result in the facility's PTE for aggregate HAP emissions exceeding the 25 tpy major source threshold. The permit record contains only an analysis of HCL and hydrogen fluoride (HF), along with 12 other HAPs that do not appear to be the most significant HAPs emitted by LWEC. That analysis is based only on certain contaminants contained within the pellet fuel, and therefore has limited bearing on the total HAP emissions from the facility.

Instead of any new, comprehensive analysis, at best it appears that LWEC and MDEQ continue to rely on a HAP analysis conducted in 2007 when LWEC converted from natural gas to biomass and waste.[31] Even assuming that the 2007 analysis was correct in determining that the facility was an area source of HAPs, which we dispute below, the fuel mix at LWEC has changed numerous times since 2007, including the addition of plastic fuel pellets at issue here. Despite this, the only HAPs that LWEC and MDEQ have quantified are the 14 HAPs listed in LWEC's application (HCL, HF, mercury, antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, nickel, magnesium, selenium, and manganese), and even that analysis suffers from defects, as explained below. What is noticeably missing from LWEC's application and the permit record is any discussion or quantification of the other 174 listed HAPs, especially the 60 to 70 or so HAPs that are common products of combustion.[32]

As we demonstrate below, when these HAPs are quantified using LWEC's stack tests and EPA's emission factors, LWEC's PTE easily exceeds the major source threshold, yet the permit record is essentially silent on this.

MDEQ and LWEC should have conducted a comprehensive review of LWEC's potential HAP emissions under the new fuel mix and made that review part of the permit record. Most significantly, LWEC's failure to provide sufficient information on HAPs requires MDEQ to deny the permit. Michigan's regulations and the state's federally enforceable State Implementation Plan require that the department "shall deny an application for a permit to install if . . . sufficient information has not been submitted by the applicant to enable the department to make reasonable judgments" as to whether "[t]he equipment for which the permit is sought will

---

[31] In 2016, MDEQ responded to similar comments by referring to a HAPs analysis conducted in 2007 when LWEC switched from natural gas as a fuel source to biomass and other fuels. *See* MDEQ Response to Comments Document for Permit No. 67-16 and Administrative Consent Order No. 35-2016 (Oct. 31, 2016), at 7.

[32] For instance, EPA's emission factor database for wood residue combustion in boilers lists and quantifies emission factors for 66 individual HAPs. *See* EPA, AP 42, Fifth Edition, Chapter 1.6, Table 1.6-3.

violate an applicable requirement of the clean air act."[33] Because LWEC has not provided any information on aggregate HAP emissions, MDEQ should not and may not issue this permit.

B. LWEC Will Continue to Be a Major Source of HAPs After the Modification.

Based on information in emission factor databases, LWEC's application, and the facility's stack test records, we calculate that LWEC will emit at least 67 HAPs in significant quantities after the modification. To estimate the emission rates for these 67 HAPs, we utilize three sources of information:

1) Where LWEC has conducted stack tests for a given HAP while combusting pellets (HCL, arsenic, lead, manganese, nickel), we utilize an emission factor based on those tests, **which results in annual emissions of 10.45 tpy**;[34]
2) For hydrogen fluoride (HF), we utilize LWEC's hourly emissions estimate of .69 lb/hr, **which results in 2.83 tpy** (as explained below, this rate should likely be 7.3 tpy);
3) For 61 additional HAPs, we utilize emission factors from EPA's AP-42 emission factor database for wood-fired boilers, **which results in 23.48 tpy**;[35]

These three sources combined result in a PTE of 33.93 tpy, readily exceeding the major source threshold (see Appendix A for detailed calculations). As discussed below, however, LWEC has under-calculated HF emissions, and utilizing the correct annual rate of 7.3 tpy results in an even higher PTE of 38.4 tpy.

Additionally, we recognize that the AP-42 emission factors for wood fuel may not be representative of emissions from the portion of the fuel mix containing TDF and pellets. This point is moot from the perspective of PTE, as the facility is authorized to burn unlimited amounts of wood chips.[36] In other words, even though the facility is authorized to burn TDF and pellets, under the terms of the permit and the fuel management plan, nothing prevents the facility from burning 100% wood. A proper PTE analysis must therefore consider the possibility of combusting 100% wood.

To further illustrate the likelihood that LWEC is a major source of HAPs, however, we also demonstrate that even under unrealistically ideal scenarios, LWEC's PTE exceed the major source threshold. Solely for the sake of argument, we calculate LWEC's PTE assuming 50% of the heat input per year is attributable to TDF and pellets, and that, miraculously, burning TDF and plastic pellets is vastly cleaner than burning wood—for this calculation we assume that burning tires and pellets emits HAPs at 50% lower levels than burning wood. This results in a PTE of 28.06 tpy, which *still* exceeds the major source threshold (and utilizing the correct HF

[33] Mich. Admin. Code R 336.1207(1)(d); nearly identical language is found in R 336.1207(c) of Michigan's SIP.
[34] The following tests were used to calculate an emission factor: arsenic: December 2017 testing, Condition One (7.41E-07 lb/MMBtu); lead: December 2017, Condition One (4.20E-06 lb/MMBtu); manganese: December 2017 testing, Condition One (2.91E-05 lb/MMBtu); nickel, December 2017 testing, Condition One (6.91E-07 lb/MMBtu); HCL: June 2018 testing (5.70E-03 lb/MMBtu) adjusted to account for the fact that the testing occurred at 90% operating capacity (i.e. 1.65 lb/hr divided by 292 MMBtu/hr = .0057 lb/MMBtu).
[35] EPA, AP 42, Fifth Edition, Chapter 1.6, Table 1.6-3.
[36] Fuel Procurement and Monitoring Plan at 2-6, (July 2016).

emission factor results in 32.5 tpy of aggregate HAPs). In reality, of course, burning TDF and plastic pellets is likely dirtier than burning wood, or at the least relatively comparable.

In responding to this comment, MDEQ must not simply rely on the HAPs analysis conducted over a decade ago for a fuel mix that is no longer combusted at this facility. Instead, MDEQ must either concede that LWEC is major source of HAPs and revise the permit accordingly (i.e. either apply major source MACT or restrict the annual heat input limits), or respond with a pollutant-by-pollutant calculation of LWEC's PTE supported by technically sound emission factors and MDEQ's analysis for why those emission factors are the most appropriate.

C. LWEC and MDEQ Improperly Estimate PTE for the 13 of 14 HAPs Listed in the Application and Technical Fact Sheet.

Although LWEC has not conducted a comprehensive HAPs analysis, the company has provided Table 8 in its application, which contains emission estimates for HCL, HF, and 12 other HAPs derived from the contaminant concentration of the fuel pellets.[37] MDEQ has incorporated this table into the Technical Fact Sheet supporting the permit.[38] This analysis suffers from several flaws, especially related to HF emissions.

First, LWEC appears to have made an error in calculating annual HF emissions, and has underestimated annual emissions by approximately 50%. The most likely cause seems to be that LWEC calculates HF emissions by multiplying the emission factor by 25,000 tons of pellets per year rather than 50,000 tpy, or perhaps LWEC has applied the 50% control rate of the DSI more than once. Whatever the cause, there is a disconnect between the hourly emission rate and the annual emission rate. LWEC estimates HF emissions from the pellets alone will be 2,894.74 pounds per year (1.44 tpy), yet using the same equations LWEC proposes, we calculate 5,500 pounds of HF per year (2.75 tpy), including the 50% control efficiency of the DSI system.[39] Alternatively, taking LWEC's hourly estimate of 0.69 lb/hr and multiplying it by 8,200 hours gives a similar rate of 5,658 pounds per year (2.829 tpy).

In addition to that error, LWEC has more fundamentally erred in calculating its PTE for HF and the 12 other HAPs listed in the table. The problem is that LWEC is not estimating the facility's true potential to emit, but rather estimating something akin to actual emissions. As courts have explained, "PTE is not to be confused with actual emissions, which may be significantly lower."[40] Stated more plainly, PTE is a "worst case emissions calculation."[41]

To estimate its PTE for HF and the 12 additional HAPs, LWEC utilizes two equations that convert the *average* maximum concentration of a given contaminant in the pellets into an hourly

---

[37] LWEC estimates the emissions for these 14 HAPs by converting the average contaminant concentration in the pellets (in parts per million) into hourly and annual emission rates. *See* July 2018 Application, Tables 4 and 8.
[38] July 2018 Application, Table 8; Technical Fact Sheet, Table 2.
[39] LWEC includes the following equation for converting from parts per million (ppm) to tons per year: tpy = (concentration (ppm)/1,000,000) x tons of pellets x (1- control efficiency). LWEC gives a control efficiency of 50%, therefore we calculate tpy as (110 ppm/1,000,000) x 50,000 tons of pellets x (1-.5) = 2.75 tpy.
[40] *Voigt v. Coyote Creek Mining Co., LLC*, No. 1:15-cv-00109, 2018 U.S. Dist. LEXIS 111913, at *84 (D.N.D. July 3, 2018).
[41] *In re Peabody Western Coal Co.*, 12 E.A.D. 22 (E.P.A. February 18, 2005), *quoting* RTC from EPA Region IX.

and an annual emission rate.[42] The problem is that LWEC has utilized an average concentration derived from eight years of pellet testing, which does not represent the worst-case annual contaminant concentration, and therefore does not represent the facility's potential emissions. For example, and most relevant to the aggregate HAP calculation, LWEC uses the fluorine concentration of 110 parts per million (ppm), which is the average fluorine content during the eight year period. 110 ppm equates to an emission rate of 0.69 lb/hr and 2.829 tpy. Using the highest annual concentration of 297 ppm, however, results in an hourly emission rate of 1.78 lb/hr and 7.42 tpy.[43]

Because PTE is a "worst case emissions calculation," as discussed above, LWEC and MDEQ must calculate PTE using the highest concentration rate that the pellets could conceivably contain, which is at least as high as the highest rate obtained from the 2011 to 2018 tests. Using an average, as LWEC has done, fundamentally undermines the concept of worst-case potential emissions—by definition, many years of higher-than-average emissions will not be represented, yet there is nothing preventing the facility from emitting at the higher rates (and in fact it stands to reason there's roughly a 50% chance the facility will exceed the average rate in any given year). To properly calculate PTE, therefore, MDEQ should use the worst-case contaminate rate from any of the prior eight years of pellet testing.

Finally, we note that Table 8 and its associated footnotes and information has numerous other errors, and we have not been able to reproduce LWEC's emission calculations with any consistency. First, as noted above, Table 8 lists the tonnage of pellets per year at 25,000 tpy, when in fact the permit will allow up to 50,000 tpy. Next, the two equations LWEC uses to convert the concentration of contaminants from ppm to hourly and annual emissions each contain errors (the annual equation is based on 15,000 tons of pellets rather than 50,000, while the hourly rate is based on 5.6 tph rather than 6 tph). Even accounting for these errors, we have not been able to repeat LWEC's calculations for most of the contaminants listed. MDEQ must explain how it verified that these emission estimates are calculated correctly and explain these discrepancies.

D. MDEQ Must Explain Why it Calculates Projected Actual HF Emissions Will be 29.31 tpy.

In the Technical Fact Sheet accompanying the draft permit, MDEQ includes "Table 1: Project Emissions Summary." Within Table 1, MDEQ shows that the projected actual emissions of "Fluorides (as Hydrofluoric Acid)" after the project will be 29.31 tpy. Table 1 also shows that baseline emissions were 57.26 tpy. The issue is the hydrofluoric acid is a HAP under the Clean Air Act,[44] meaning that if these rates are correct, and this facility has been emitting nearly 60 tons of hydrofluoric acid per year, and will continue to emit around 30 tpy, the facility is plainly a major source of HAPs. Further, the Technical Fact Sheet from 2017 accompanying PTI No. 53-1, lists projected actual emissions of "Fluorides" as 12.65 tpy, and baseline emissions as 14.09 tpy. While fluorides are not designated as a HAP, if more than 10 tons of the fluoride emissions

[42] July 2018 Application, Table 8.

[43] Hourly rate: (297 ppm/1,000,000) x 6 tons of pellets per hour x 2,000 lb/ton x (1-0.5) = 1.78 lb/hr; annual rate (297 ppm/1,000,000) x 50,000 tons of pellets per year x (1-0.5) = 7.42 tpy.

[44] 42 U.S.C. § 7412(b)(1), listing CAS Number 7664393 "hydrogen fluoride (hydrofluoric acid)."

are emitted as hydrofluoric acid/hydrogen fluoride, then again, this rate qualifies the facility as a major source of HAPs.

We have spoken with the permit writer for this project, who has acknowledged that the 29.31 tpy and 57.26 tpy rates listed in the current Technical Fact Sheet are not correct. We have not, however, received any further information by the close of the public comment period as to the source of the error and what the true rates are. We therefore ask that MDEQ explain the origin of the error and provide adequate information to support whatever rates MDEQ believes are correct.

E. MDEQ Should Require Additional HAPs Testing to Confirm or Refute LWEC's Status as an Area Source.

Ideally, LWEC should be required to conduct stack tests for as many HAPs as possible to better establish the aggregate HAP emission rates and ensure that no single pollutant exceeds either the permit limit or the major source threshold. At a minimum, however, MDEQ should require HAPs testing of the following HAPs that likely constitute the largest share of HAP emissions (based on AP-42 emission factors and other sources, as noted) that have yet to be tested:

- **Hydrofluoric acid/hydrogen fluoride.** LWEC estimates emissions are 1.44 tpy, however we calculate that they are at least 2.83 tpy and possibly as high as 7.3 tpy (and of course MDEQ has stated they are as high as 27.95 tpy, as discussed above);
- **Formaldehyde**. AP-42 emission factors show emissions at LWEC are 5.84 tpy;
- **Benzene**. AP-42 emission factors show emissions at LWEC are 5.58 tpy; a study of plastic combustion ranked benzene emissions as the highest out of 24 compounds tested;[45]
- **Acrolein.** AP-42 emission factors show emissions at LWEC are 5.31 tpy;
- **Styrene.** AP-42 emission factors show emissions at LWEC are 2.52 tpy;
- **Toluene.** AP-42 emission factors show emissions at LWEC are 1.22 tpy;
- **Acetaldehyde.** AP-42 emission factors show emissions at LWEC are 1.1 tpy;
- **Chlorine.** AP-42 emission factors show emissions at LWEC are 1.05 tpy.

MDEQ should also include testing for any additional HAPs which it believes, using sound engineering practices, are potentially emitted in relatively high quantities by combusting plastic.

F. MDEQ Should Provide Additional Information Related to the Rule 225 Toxics Analysis.

According to the Technical Fact Sheet, MDEQ reviewed LWEC's evaluation of new toxic air contaminant (TAC) emissions that LWEC says will result from the burning of plastic pellets. That analysis included only the 14 toxics listed in Table 13 of LWEC's application. MDEQ does further state that "77 other TACs [toxic air contaminants] were evaluated," but provides very little detail on this evaluation.[46] As discussed above, many of the 14 TACs listed and evaluated

---

[45] Barabad, Mona Loraine, *et al.*, "Characteristics of Particulate Matter and Volatile Organic Compound Emissions from the Combustion of waste Vinyl," International Journal of Environmental Research and Public Health, (July 2, 2018), at 5. (Attachment D).

[46] Technical Fact Sheet at 4.

by LWEC do not appear to be the most significant TACs emitted LWEC, and nothing in the permit record discusses what information was used to model impacts from the other 77 TACs, let alone which TACs were included in this analysis. MDEQ should provide additional information on which TACs were evaluated and how MDEQ ascertained potential emission rates for those TACs.

Additionally, neither LWEC nor MDEQ indicate whether the ambient impacts analysis included TAC emissions from the adjoining CertainTeed facility. CertainTeed operates numerous units that are potential sources of TACs, including coating and spraying operations that are potential sources of organic toxics, as well as the 27 MMBtu/hr boiler.[47] To properly evaluate the impacts on the citizens of L'Anse, MDEQ must ensure that TAC emissions from CertainTeed and any other potential sources are included in evaluating whether emissions exceed the health-based screening levels.

III. The Draft Permit Suffers From Numerous Deficiencies Related to HCL Emissions.

Combusting plastic-laden pellets has the potential to emit substantial levels of HCL emissions—LWEC itself estimates that uncontrolled HCL emissions would be approximately 77 tpy.[48] As MDEQ is aware, in 2015 LWEC conducted stack testing for HCL that showed emissions were more than twice the 10 tpy major source threshold. With this context in mind, the draft permit contains numerous, troubling deficiencies with regards to the enforceability of limits on HCL emissions, the monitoring of HCL emissions, and the implementation and use of a new DSI control system to reduce HCL emissions.

A. The Draft Permit Improperly Exempts LWEC From the Hourly HCL Limit.

The current permit and all prior permits for LWEC contain two independent limits on HCL emissions; first, LWEC is subject to an hourly limit of 2.17 lb/hr, and second, an annual limit of 9.5 tons per year. The hourly limit was established under the requirements of Mich. Admin. Code R 336.1224 (Best available control technology for toxics (T-BACT)) and Mich. Admin. Code R 336.1225 (health-based screening level requirements for new or modified sources of air toxics).[49] The annual limit, meanwhile, was established to avoid the application of MACT.[50] Despite the fundamentally distinct underlying requirements for the hourly and the annual limits, the draft permit would, for the first time, allow LWEC to choose which limit applies. That's because the HCL limits have been joined and phrased as "2.17 pph -or- 9.5 tpy." This option essentially eliminates the hourly limit, and severely reduces the enforceability of the annual limit.

1. Eliminating the Hourly HCL Limit is Inappropriate and Likely Unlawful.

By eliminating the need to comply with the hourly limit, the permit exempts LWEC from the limits established to satisfy the health based screening requirements and the T-BACT

[47] MDEQ, PTI No. 315-01B (Nov. 7, 2014).
[48] We make this calculation using LWEC's equation from Table 8, except we do not include any control efficiency.
[49] Draft Permit at 7.
[50] *Id.*

requirements. The Technical Fact Sheet is devoid of any discussion of how MDEQ believes it has the authority to now exempt LWEC from the requirements of these two provisions. If MDEQ believes that it does have this authority, it must explain so in the permit record.

Further, eliminating the hourly HCL limit when the facility is introducing plastic-laden pellets is especially unreasonable. As LWEC acknowledges, burning plastic is a significant source of HCL emissions, and hence necessitates the use of the DSI control. An hourly limit on HCL emissions is needed to ensure that the facility does not release harmful amounts of HCL in short periods of time when the DSI control may be malfunctioning or operating at less than ideal control efficiencies. In other words, MDEQ is eliminating the hourly HCL limit at the same time that the risk of high hourly HCL emissions is increasing substantially.

Finally, it is likely that prior impact modeling for HCL emissions, if any has occurred (we have not been able to gain access to documents from 2007 when this facility switched from natural gas to biomass), relied upon the maximum hourly limit of 2.17 lb/hr to evaluate short term impacts. Removing this limit therefore may render any prior impact modeling moot. We note that LWEC did conduct an additional impact evaluation for HCL emissions at rates higher than 2.17 lb/hr in its application for the current permit, however it is unclear whether MDEQ reviewed and approved that evaluation, as HCL is not listed amongst the pollutants included in the Technical Fact Sheet's "Table 2: Toxic Air Contaminant Impacts."

2. Allowing LWEC to Choose Which Limit Applies Eliminates the Enforceability of the 12-Month Rolling Limit.

Although complying with the 2.17 lb/hr HCL limit is effectively the equivalent of complying with the annual limit, the fact that the permit allows LWEC to comply with the hourly limit instead of the annual limit would seem to eliminate the 12-month rolling average requirements of the draft permit. The draft permit condition relating to the HCL limits state that compliance with the HCL limits shall be determined on an "Hourly -or- 12 month rolling average as determined at the end of each calendar month if using a CPMS."[51] The wording of this condition therefore seems to exempt LWEC from calculating its 12-month rolling average if the facility opts to comply instead with the hourly limit. Without requiring LWEC to calculate its 12-month rolling HCL emissions, the permit is essentially devoid of any enforceable conditions requiring the facility to monitor its annual emissions, which is an especially unreasonable result given this facility's history of non-compliance with HCL emissions.

MDEQ should remedy these issues by continuing to require that LWEC comply with both an hourly and a yearly emission limit. We note that LWEC themselves have stated that "[s]tack test data demonstrates that emissions will be under 2.17 lb/hr HCL at 6 tph pellets."[52]

B. The Compliance Monitoring System for HCL Emissions is Inadequate to Assure HCL Emissions Remain Below the 9.5 tpy Limit and the 10 tpy Major Source Threshold.

[51] Draft permit at 7.
[52] July 2018 Application at 1.

The draft permit purports to implement improved HCL emissions monitoring, requiring the installation and use of what the permit calls a Compliance Monitoring System (CMS). Yet the new monitoring scheme is so thin on details that it is essentially impossible to discern how exactly LWEC must monitor HCL emissions. As a result, the "improved" monitoring may in fact be a step backwards compared to the previous monitoring method, which was based simply on an emission factor multiplied by heat input. While we do not wish to see LWEC revert to the old method, the new CMS monitoring must be thoroughly improved and the details must be included in the draft permit and subject to public review and comment.[53]

The CMS is the draft permit's only monitoring requirement for HCL emissions other than the once-per-five-year testing requirement. Despite the reliance on the CMS, the permit and LWEC's application fail to define what exactly constitutes the CMS. In fact, LWEC's application doesn't even reference anything called CMS or 'compliance monitoring system.' Instead, the application merely gives many different options for monitoring that LWEC "may" or "might" utilize, all of which loosely fall under the umbrella of continuous parametric monitoring systems. Worse yet, the draft permit itself fails to require any particular monitoring under the framework of the CMS, as it allows LWEC to use "an alternative method approved by the AQD for HCL monitoring."

Even assuming LWEC does implement CMS under the terms of the draft permit, it is still completely ambiguous as to how the CMS shall function or how LWEC will actually, in the day-to-day course of operations, monitor HCL emissions. The only discernable aspects of the CMS are found in Special Condition (2) under Part VI of the draft permit's EUBOILER#1 section, which states that the CMS must, at a minimum, include the following:

a. The CMS that will include provisions for alternative monitoring in the event that the CMS is not operational or is out of control. The alternative monitoring shall, [sic] require verification of alternative operating parameters if new operating parameters are introduced.
b. The CMS will describe the process monitors and include data from stack testing allowing the correlation between emissions and HCl information available from the continuous monitor.
c. The CMS will include monitor maintenance activities as well as ongoing calibration activities to ensure compliance with HCl limits.
d. A CMS will include using the reagent injection rate from a process monitor.
e. Emission factors developed through use of the CMS, including the HCl levels in ppm or lb/hr necessary to maintain compliance and correlating reagent injection rates used in the calculations, will be recorded and kept onsite.
f. The permittee shall submit any amendment to the CMS (i.e. continuous parameter monitoring system (CPMS) to AQD district supervisor for review and approval. A monitoring plan and testing plan shall be submitted at least 90 days prior to any testing or implementation. Upon approval of the amended plan by the AQD district supervisor, the permittee shall implement the amended CMS.

---

[53] As EPA has explained, "compliance monitoring and recordkeeping and reporting requirements are necessary to make permit limitations enforceable as a practical matter." EPA, Limiting Potential to Emit in New Source Permitting (June 13, 1989), at 17. *Available at:* https://www3.epa.gov/airtoxics/pte/june13_89.pdf.

The only somewhat concrete requirements of the CMS that can be gleamed from this list is that stack test data and the reagent injection rate must be used somehow, in an unspecified manner, to develop a system that monitors compliance. Essentially, it appears that LWEC can develop any method it wishes to "monitor" emissions, whether or not that method has any bearing on actual emissions. While the draft permit does seem to require some sort of approval by AQD of a "Performance Specification" in relation to the CMS, the draft permit is silent on when LWEC must request this approval, and what approval entails.[54]

The list of CMS requirements is also telling in terms of what it omits—the amount of each type of fuel being combusted at any given time, the chlorine and moisture content of that fuel, the temperature and moisture content of the flue gas, the particle size of the sorbent (i.e. the degree of milling conducted prior to injection), and the operating parameters of the ESP (which is ultimately responsible for capturing the sorbent/HCL mix), each of which is a key component of HCL emissions and DSI control efficiency.[55]

C. The Draft Permit Fails to Establish Minimum DSI Parameters Necessary to Ensure HCL Emissions Remain Below the Major Source Threshold.

LWEC conducted four sets of stack tests at varying levels of pellet feed, from 2.85 tph to 6 tph, while adjusting the DSI injection rate upwards as the pellet feed increased. Ultimately, the permit authorizes the facility to burn up to 6 tph of pellets, but the draft permit fails to establish any minimum DSI injection rates that correspond to that pellet combustion rate. In order to ensure that HCL emissions remain below the major source threshold, the draft permit must incorporate an enforceable permit condition implementing minimum reagent injection rates. Without these minimum rates, and without adequate emissions monitoring, LWEC cannot account for the operation of the DSI in calculating its PTE, meaning the facility's PTE exceeds the major source threshold.[56]

LWEC indicates that it intends to vary the rate of DSI injection to match the rate of pellets combusted at any given time.[57] While this presents additional issues related to monitoring the rate of pellet combustion, discussed below, this fact should not prevent MDEQ from implementing minimum injection rates. For instance, MDEQ could formulate an equation that establishes the minimum injection rate based on the tonnage of pellets combusted per hour.

D. LWEC Must Explain How it Will Monitor Pellet Combustion Rates.

As LWEC itself recognizes, the facility will need to be able to accurately monitor the rate of pellets being combusted in order to adjust the reagent injection rate (unless a flat minimum rate is implemented that is independent of the pellet combustion rate) and also to accurately monitor

---

[54] Draft Permit Condition VI.2.

[55] Sewell, Melissa, *et al.*, "Optimising Dry Sorbent Injection Technology," World Cement (Apr. 2015), *available at:* https://www.sorbacal.com/sites/default/files/downloadcenter/wct_april-2015.pdf. (Attachment E).

[56] As noted above, LWEC estimates that uncontrolled HCL emissions would be 77 tpy.

[57] Permit Application at 7 ("Testing indicates that maintaining an injection rate at any particular pellet combustion rate will ensure compliance. A curve will be established demonstrating injection rates for different pellet rates.").

HCL emissions.[58] Unfortunately, LWEC seems to lack the capability to track individual fuel consumption rates on relatively short time-frames—apparently LWEC cannot monitor fuels on an hourly or shorter basis, and only determines the rate of each fuel burned at the end of the day.[59]

Without knowing the level of pellets being combusted at any given time, it's hard to imagine how LWEC will be able to apply the proper reagent injection rate. Unless a minimum injection rate is established, as described above, the DSI system cannot be considered in accounting the facility's PTE for HCL and aggregate HAPs.[60]

Further, without accurate information on the pellet rate and the effectiveness of the related reagent injection rate, LWEC can't possibly determine HCL emission rates in an accurate manner. For instance, combusting 6 tph of pellets versus 4 tph—or 50% more pellets—would seem to have a significant impact on HCL emissions unless the reagent rate is properly adjusted, yet how can LWEC do that if they don't know how many tons of pellets they are burning at any given moment?

MDEQ can remedy this by either requiring LWEC install and operate a system to measure the rate of pellets combusted on a real-time basis, or by implementing permit conditions that assume that any time LWEC combusts pellets, it is doing so at the maximum rate of 6 tph (i.e. by requiring the maximum level of DSI injection).

E. The Draft Permit Must Limit the Plastic Content of the Fuel Pellets.

While the draft permit does restrict the maximum usage of pellets, it fails to restrict the maximum plastic content of the fuel pellets. LWEC estimates that the engineered fuel pellets contain approximately 60 to 70% fiber/paper material and 30 to 40% clean plastic. Combined with the 50,000 tpy limit on pellets, this means the facility intends to burn up to 20,000 tpy of plastic, and has apparently based potential emissions estimates on that ratio. The draft permit, however, does not restrict the content of the pellets in any way, meaning the facility could burn pellets containing any ratio of plastic, potentially all the way up to 100% (or 50,000 tons of plastic). The difference between burning 20,000 tons of plastic versus 50,000 tons of plastic per year would have a substantial impact on emissions, especially if the DSI system is operating as though the pellets contained only 30 to 40% plastic. Therefore MDEQ must implement a condition limiting the plastic content of the pellets to no more than 40% and require adequate monitoring, recordkeeping, and reporting requirements to ensure the facility complies with the limit.

---

[58] July 2018 Application at 7 ("Testing indicates that maintaining an injection rate at any particular pellet combustion rate will ensure compliance. A curve will be established demonstrating injection rates for different pellet rates.").

[59] MDEQ, Response to Comments on Permit No. 67-16 and Administrative Consent Order No. 35-2016 (Oct. 31, 2016), at 10.

[60] EPA is clear that for controls to count in restricting PTE, the permit must contain a minimum destruction efficiency or other limits that ensure adequate destruction rates are achieved, as well as monitoring, recordkeeping, and reporting requirements to ensure the efficiency limit is enforceable. *See* EPA, Limiting Potential to Emit in New Source Permitting (June 13, 1989), at 21. *Available at:* https://www3.epa.gov/airtoxics/pte/june13_89.pdf.

Additionally, MDEQ must limit the type of plastic contained within the pellets. LWEC's application lists the types of plastics that make up the pellets as "Primary: polyethylene, polypropylene, polyester, nylon, trace amounts of others."[61] As Table 4 of LWEC's application shows, the contaminant concentration of the pellets has varied considerably over time—for instance fluorine has measured as high as 297 ppm and as low as 5 ppm, while chlorine has waivered from 709 ppm to 2,497 ppm. This variation may be due to the types of plastic in the pellets. MDEQ should therefore limit the type of plastic that LWEC can combust to only those types which LWEC has demonstrated via stack testing will not lead to exceedances of the HAP limits.

IV. The Draft Permit Must Include the Emission Factors LWEC Shall Use to Calculate Individual and Aggregate HAP Emissions.

The draft permit implements limits that attempt to restrict the facility's PTE for individual and aggregate HAPs to below the relevant major source MACT thresholds.[62] These limits restrict individual HAP emissions to 9.5 tpy and aggregate HAP emissions to 20 tpy.[63] The draft permit also requires LWEC to calculate and report its individual and aggregate HAP emissions using emission factors "based on testing at the facility or as approved by the AQD District Supervisor."[64] Nothing in the draft permit nor the permit record indicates what particular emission factors LWEC shall use, nor even which HAPs LWEC must quantify. This lack of information in the permit and permit record renders the emission limits unenforceable as a practical and legal matter.

As EPA has consistently explained, a limit intended to restrict PTE "can be relied upon . . . only if it is legally and practicably enforceable."[65] EPA has further explained practical enforceability as such:

> In order to be considered practically enforceable, an emissions limit must be accompanied by terms and conditions that require a source to effectively constrain its operations so as to not exceed the relevant emissions threshold. **These terms and conditions must also be sufficient** to enable regulators and **citizens** to determine whether the limit has been exceeded and, if so, to take appropriate enforcement action.[66]

Without the emission factors in the permit, it is impossible for citizens to "determine whether the limit has been exceeded."[67]

---

[61] July 2018 Application, Table 2.
[62] Draft Permit at 22.
[63] *Id.*
[64] Draft Permit at 23.
[65] *In the Matter of Kentucky Syngas, LLC*, Order on Petition No. IV-2010-9, at 30 (E.P.A. June 22, 2013), https://www.epa.gov/sites/production/files/2015-08/documents/kentuckysyngas_response2010.pdf.
[66] *In the Matter of Orange Recycling & Ethanol Prod. Facility, Pencor-Masada Oxynol, llc.*, Order on Petition No. II-2001-05, at 7 (E.P.A. Apr. 8, 2002), https://www.epa.gov/sites/production/files/2015-08/documents/masada-2_decision2001.pdf; *see also In re Piedmont Green Power, LLC*, Order on Petition No. IV-2015-2 (Dec. 13, 2016), at 14.
[67] *In the Matter of Orange Recycling & Ethanol Prod. Facility, Pencor-Masada Oxynol, llc.*, *supra*, note 66.

More specifically, EPA has explained that where "[a permitting authority] decides to continue utilizing emission factors to determine HAP emissions, the permit record must support the selected emission factors . . . for each HAP."[68] Finally, EPA requires that both the list of HAPs that must be calculated and the method for determining monthly emissions must be included in the permit itself.[69] In the context of a similar biomass power plant permit that only explicitly accounted for HCL emissions, EPA explains:

> **Without a clear identification in the Final Permit of which HAP** other than HCl must be included in the required monthly emission calculation and without a clearly identified method for determining monthly emissions for each such HAP, **the limitations on individual HAP and total HAP emissions are legally and practically unenforceable.**[70]

Such is the case in with the draft permit. Without understanding even the most basic issue—which of the 187 listed HAPs must be quantified—it is impossible for the public, EPA, and even MDEQ to enforce the HAP provisions of the draft permit. Likewise, MDEQ has completely failed to provide support for the selected emission factors, let alone incorporate those emission factors into the permit.

We point out that EPA's emission factor database (AP-42) contains emission factors for 66 HAPs from wood fired boilers (and we note again that using these emission factors, LWEC is exceeding the permit limit and major source threshold for aggregate HAPs); MDEQ must at a bare minimum require LWEC to calculate its emissions of these 66 HAPs and any other HAPs that MDEQ believes LWEC emits. Finally, MDEQ must provide technical support for each of the emission factors chosen, especially where MDEQ utilizes an emission factor that is lower than those given by AP-42.

V. The Draft Permit Improperly Omits Monitoring, Recordkeeping, and Reporting Requirements for PM, NOx, VOC, and Sulfur Dioxide (SO_2) Emissions.

Nothing in the draft permit requires LWEC to calculate, record and report its monthly and 12-month rolling emissions of PM, NOx, VOCs and SO_2. This is in contrast to prior PTIs issued to LWEC, which did require the facility to make and record these calculations.[71] It's unclear whether this is an oversight or whether MDEQ intends to relax the monitoring, recordkeeping, and reporting requirements that apply to LWEC. At a bare minimum, these monitoring requirements must be retained in order to assure that this facility complies with Title V's periodic monitoring requirements (and, as discussed in comments we submitted on the draft renewal Title V permit for this facility, those monitoring provisions must be significantly strengthened[72]).

---

[68] *In re Piedmont Green Power, LLC*, Order on Petition No. IV-2015-2 (Dec. 13, 2016), at 15, *available at: https://www.epa.gov/sites/production/files/2016-12/documents/piedmont_response2015.pdf*.
[69] *Id.*
[70] *Id*.
[71] *See, e.g.* PTI No. 53-17A, EUBIOLER#1, Conditions VI.4, VI.9, VII.1, and VII.2.
[72] *See* Comments submitted by Environmental Integrity Project on behalf of FOLK and Partnership for Policy Integrity on draft Permit No. MI-ROP-B4260-20XX (July 26, 2017).

The lack of monitoring, recordkeeping, and reporting requirements is especially troubling in relation to NOx and VOC emissions, given the inadequate and technically-flawed estimates made by LWEC for post-project actual emissions, as discussed above. Ideally, MDEQ should require the installation of a continuous emissions monitoring system (CEMS) at least for NOx, in order to obtain real time data on NOx emissions (we note that LWEC already operates a CEMS system for CO, a pollutant which the facility emits in lower amounts). We also note that previous comments submitted concerning this facility demonstrated that the vast majority of power plants in Michigan utilize CEMS for NOx.[73]

If MDEQ doesn't not require CEMS, MDEQ must at a minimum reinstate the previous monitoring and recordkeeping requirements, although we point out that MDEQ must make the emission factors and the basis for the chosen emission factors available for public review and incorporate those emission factors into the permit.[74]

Finally, for any pollutants that may be impacted by the use of the DSI system, MDEQ must require the use of emission factors that reflect the use of the DSI system. For instance, for SO_2 emissions, the DSI system will likely result in a significant decrease in emissions when operating, but LWEC need only operate the DSI system when combusting pellets. Therefore, at a minimum, LWEC must be able to accurately account for its SO_2 emissions both when the DSI system is operating and when it is not.

VI. The Permit Must Address the Relationship Between the DSI System and the Electrostatic Precipitator (ESP).

When LWEC conducted stack tests while operating the DSI system, PM emissions decreased significantly from prior tests. While this is a welcome decrease, information supplied by the Institute of Clean Air Companies indicates that DSI systems may actually lead to increased PM emissions. That's because the use of certain sorbents, especially calcium-based sorbents, will "increase the resistivity of the fly ash making the ash more difficult to charge and capture" in an ESP.[75] To ensure that post-project PM emissions do not increase significantly, MDEQ must require that LWEC continue to operate the DSI system in a manner consistent with how it operated the system during testing. Further, MDEQ should increase the frequency of PM tests from once every five years to, ideally, once per year; at a minimum MDEQ should require testing at least every three years, as EPA has already suggested is appropriate for this facility even before the installation of the DSI system.[76]

VII. MDEQ Has Eliminated Particulate Matter Limits that Formerly Applied to the Sorbent Storage and Handling Operations Without Explanation.

---

[73] *See* Comments submitted by Olson, Bzdok Howard on behalf of FOLK and Partnership for Policy Integrity on draft Permit No. MI-ROP-B4260-20XX (July 26, 2017).
[74] *In re Piedmont Green Power, LLC*, Order on Petition No. IV-2015-2 (Dec. 13, 2016), at 15 (explaining that if "[the permitting authority] decides to continue utilizing emission factors to determine HAP emissions, the permit record must support the selected emission factors . . . for each HAP.").
[75] July 2018 Application, Appendix 2, at 12-13.
[76] USEPA Comments on Draft Permit to Install 67-16.

The permits authorizing the pellet test trials placed limits on PM, PM10, and PM2.5 emissions on the sorbent silo of 0.01 gr/dscf, citing to both Michigan's standards for particulates (listed as Rule 336.1331) and the federal PSD regulations concerning ambient air increments and ambient air ceilings.[77] Even LWEC's application acknowledges that these limits are necessary, stating that "[e]mission limits under Rule 331 also apply to the EUSORBENT system."[78]

Those limits have not been incorporated into the draft PTI, and the only limit on the sorbent storage and handling operations is a 5% opacity limit. The Technical Fact Sheet does not provide an explanation for the elimination of the PM limits. We believe these limits continue to apply and must remain in the permit. Further, given the community complaints involving dust and particulates, it is especially unreasonable to relax limits on particulates.[79]

VIII. MDEQ Must Regulate the Facility as a Commercial and Industrial Solid Waste Incinerator (CISWI) or Provide More Information on Why LWEC is Exempt.

LWEC claims that it is exempt from the New Source Performance Standards for CISWI units (set forth at 40 CFR 60, Subpart DDDD) under the "small power production facilities" exemption.[80] In order to qualify for that exemption, one key condition is that the power plant must burn "homogeneous waste."[81] As multiple commenters on past permits for LWEC have pointed out, it is difficult to comprehend how burning a mix of creosote treated railroad ties, TDF, natural gas, and now plastic/paper pellets constitutes burning "homogeneous waste."

In response to these prior comments, MDEQ has largely deferred to an August 27, 2014 letter from LWEC setting forth the claim that the facility qualifies for the small power production facility exemption.[82] To support the claims in the August 2014 letter, LWEC cites only to its fuel procurement and management plan and its self-certification as a small power production facility. None of these materials explain how the facility's fuel mix qualifies as "homogeneous waste." MDEQ must provide independent justification for why the diverse and substantially heterogeneous fuel mix combusted at LWEC qualifies as "homogeneous waste" within the meaning of the small power producer exception. In the alternative, if MDEQ cannot explain how the fuel mix qualifies as "homogeneous waste," MDEQ must find that the small power producer exemption does not apply to LWEC and begin regulating the facility under the CISWI regulations.

IX. This Public Notice and Comment Period is Not Sufficient to Modify LWEC's Renewable Operating Permit (ROP).

The public notice for the draft PTI states that "the permanent combustion of the engineered fuel pellets will require revisions to Renewable Operating Permit (ROP) No. MI-ROP-B4260-2011

---

[77] *See* PTI No. 53-17A, page 13.
[78] July 2018 Application at 9.
[79] *See, e.g.,* MDEQ Violation Notice issued Feb. 8, 2016, noting "several recent complaint [sic] which we received . . . regarding fugitive dust, black smoke, and foul odors attributed to LWEC's operations."
[80] 40 CFR § 60.2020(e).
[81] *Id*.
[82] MDEQ Response to Comments Document for Permit No. 67-16 and Administrative Consent Order No. 35-2016 (Oct. 31, 2016), at 8-9.

SRN B4260)" and further that "[t]his public comment period meets the public participation requirements for a future administrative amendment to the ROP." With these statements, it appears that MDEQ intends to revise the ROP to incorporate the draft PTI without releasing the draft ROP for additional public comment and potentially without the requisite EPA review. This scenario contravenes the significant modification requirements of Title V permitting.

First, the changes to LWEC's operations authorized under the draft PTI do not meet the definition of an administrative amendment. Administrative amendments include such revisions as "correction of typographical errors, changes in mailing address, ownership of the facility, contact persons, and persons who have been assigned responsibilities under the permit."[83] On the other hand, revising the fuel mix, increasing NOx emissions (especially the fact that the project is a major modification under PSD, as discussed above), revising the HCL monitoring provisions, and eliminating the hourly HCL limit are all modifications that qualify as significant modifications rather than administrative or minor modifications.[84]

Finally, although certain preconstruction permits may be incorporated into Title V permits by administrative amendment, it is not clear that MDEQ has followed the proper procedure to do so. In order for a preconstruction permit authorizing a modification that qualifies as significant to be eligible for incorporation via administrative amendment, the preconstruction permit must be subject to essentially the same procedures as a significant modification.[85] This includes review by the EPA and affected states, as well as the ability for the public to petition EPA to object.[86] Nothing in the permit record indicates that this draft permit has or will be submitted to EPA for review, nor does the draft permit appear on MDEQ's public notice page for ROP actions.

X. Many Issues Identified in Our July 26, 2017 Comments Must Still be Addressed.

On July 26, 2017, EIP submitted comments on behalf of itself, FOLK, and PFPI on draft PTI No. 53-17 and draft ROP renewal No. MI-ROP-B4260-20XX. Although MDEQ has issued PTI No. 53-17, apparently without responding to comments, several of the issues we raised then remain present in the current draft PTI:

- As explained previously, the draft PTI fails to incorporate by reference a specific FPMP and also fails to specifically identify the required monitoring methods. Just as this

[83] *In re Peabody W. Coal Co.*, 15 E.A.D. 757, 760 (E.P.A. January 25, 2013), citing 40 CFR § 71.7(d)(1) (identical language is found at 40 CFR 70.7

[84] Under the relevant Part 70 provisions and Michigan's regulations, significant modifications are defined as modifications that cannot be achieved by administrative amendment or by minor modification. 40 CFR § 70.7(e)(4); Mich. Admin. Code r. 336.1216(3)(a). In relevant part, significant modifications have been further defined under Michigan's regulations to include a "modification under any applicable provision of title I of the clean air act," (e.g. a modification under the PSD provisions such as the addition of the engineered fuel pellets, which results in a major modification under PSD regulations); changes that significantly affect existing monitoring, recordkeeping, or reporting (e.g. the revised HCL monitoring and the elimination of NOx, VOC, PM and SO_2 monitoring, recordkeeping and reporting); and "any change that would result in emissions that exceed the emissions allowed under the renewable operating permit (i.e. the removal of the HCL hourly limit that would allow hourly emissions to exceed the current limit of 2.17 lb/hr). *Id.*

[85] 40 CFR 70.7(d)(v).

[86] *Id.*

approach is insufficient for a Title V permit, it also is inappropriate for a Permit to Install, especially in a PTI for a Title V source.

- On page 9, the draft permit states that the permittee "shall not process, store, or combust any railroad ties, or any materials, which have been treated with pentachlorophenol coating or preservative." MDEQ must amend the permit to specify how LWEC will ensure compliance with this limitation. Currently, the only compliance provisions associated with this condition is a reference on page 8 to the FPMP, which as discussed in our comments, is not sufficient to assure compliance unless a specific version of the FPMP is incorporated by reference.

Conclusion

MDEQ must make substantial revisions to the draft permit before issuance and reissue the draft permit for additional public notice and comment. Most significantly, because the proposed project is a major modification, MDEQ must require LWEC to apply for a major source PSD permit and implement BACT limits that significantly reduce NOx emissions. Additionally, MDEQ must either require compliance with major source MACT, implement significant operating limits to restrict HAP emissions to area source levels, or provide adequate justification for why LWEC is actually an area source. Finally, MDEQ must address the relaxation or elimination of HCL and PM limits, the inadequate monitoring provisions, and the other issues raised above before issuing the PTI.

Respectfully submitted,

s/ Patrick J. Anderson

____

Patrick J. Anderson
Of Counsel, Environmental Integrity Project
E: panderson@powellenvironmentallaw.com
T: (719) 963-4072

Keri N. Powell
Of Counsel, Environmental Integrity Project
E: kpowell@powellenvironmentallaw.com
T: (917) 573-8853

Mailing Address
Environmental Integrity Project
c/o Powell Environmental Law
315 W. Ponce de Leon Ave.
Suite 842
Decatur, GA 30030

On behalf of the Friends of the Land of Keweenaw and Partnership for Policy Integrity.

Attachments: Attachments A through E.

Appendix A: Emissions Calculations

Table 1: HAP PTE Calculations.

Emissions from all fuels (2,656,800 MMBtu/year)			
Emission factor source	HAP	Emission Factor	TPY
2017-2018 stack tests	HCL	5.70E-03	7.57E+00
	Arsenic	7.41E-07	9.84E-04
	Lead	4.20E-06	5.58E-03
	Manganese	2.91E-05	3.87E-02
	Nickel	5.03E-07	6.68E-04
LWEC Application	Hydrogen fluoride	2.13E-03	2.83E+00
AP-42	Formaldehyde	4.40E-03	5.84E+00
	Benzene	4.20E-03	5.58E+00
	Styrene	1.90E-03	2.52E+00
	Acrolein	4.00E-03	5.31E+00
	Antimony	7.90E-06	1.05E-02
	Beryllium	1.10E-06	1.46E-03
	Cadmium	4.10E-06	5.45E-03
	Chromium	2.10E-05	2.79E-02
	Cobalt	6.50E-06	8.63E-03
	Mercury	3.50E-06	4.65E-03
	Phosphorus	2.74E-05	3.64E-02
	Selenium	2.80E-06	3.72E-03
	Acetaldehyde	8.30E-04	1.10E+00
	Acetophenone	3.20E-09	4.25E-06
	Carbon Tetrachloride	4.50E-05	5.98E-02
	Chlorine	7.90E-04	1.05E+00
	Chlorobenzene	3.30E-05	4.38E-02
	Chloroform	2.80E-05	3.72E-02
	2,4-Dinitrophenol	1.80E-07	2.39E-04
	Bromomethane	1.50E-05	1.99E-02
	Chloromethane	2.30E-05	3.06E-02
	1,2-Dichloroethane	2.90E-05	3.85E-02
	1,2-Dichloropropane	3.30E-05	4.38E-02
	Ethylbenzene	3.10E-05	4.12E-02
	Napthalene	9.70E-05	1.29E-01
	4-Nitrophenol	2.40E-07	3.19E-04
	Pentachlorophenol	5.10E-08	6.77E-05
	Phenol	5.10E-05	6.77E-02
	Propionaldehyde	6.10E-05	8.10E-02
	Toluene	9.20E-04	1.22E+00
	Tetrachloroethane	3.80E-05	5.05E-02

	2,3,7,8-Tetrachlorodibenzo-p-dioxin	8.60E-12	1.14E-08
	1,1,1-Trichloroethane	3.10E-05	4.12E-02
	2,4,6-Trichlorophenol	2.20E-08	2.92E-05
	Vinyl Chloride	1.80E-05	2.39E-02
	Acenaphthene	9.10E-07	1.21E-03
	Acenapthylene	5.00E-06	6.64E-03
	Anthracene	3.00E-06	3.99E-03
	Benzo(a)anthracene	6.50E-08	8.63E-05
	Benzo(a)pyrene	2.60E-06	3.45E-03
	Benzo(g,h,i)perylene	1.00E-07	1.33E-04
	Benzo(l,k)fluoranthene	2.60E-09	3.45E-06
	Benzo(k)fluoranthene	9.30E-08	1.24E-04
	2-Chloronapthalene	1.60E-07	2.13E-04
	Chrysene	3.60E-08	4.78E-05
	Dibenzo(a,h)anthracene	2.40E-09	3.19E-06
	Fluoranthene	1.60E-06	2.13E-03
	Fluorene	3.40E-06	4.52E-03
	Indenol(1,2,3,c,d)pyrene	8.70E-08	1.16E-04
	Monochlorobiphenyl	2.20E-10	2.92E-07
	2-Methylnapthalene	1.60E-07	2.13E-04
	Phenathrene	7.00E-06	9.30E-03
	Pyrene	3.70E-06	4.92E-03
	Perylene	5.20E-10	6.91E-07
	Decachlorobiphenyl	2.70E-10	3.59E-07
	Dichlorobiphenyl	7.40E-10	9.83E-07
	Heptachlorobial	6.60E-11	8.77E-08
	Hexachlorobiphenyl	5.50E-10	7.31E-07
	Pentachlorobiphenyl	1.20E-09	1.59E-06
	Trichlorobiphenyl	2.60E-09	3.45E-06
	Tetrachlorobiphenyl	2.50E-09	3.32E-06
		Sum of all emissions (tpy):	33.93

Notes:

1. AP-42 emission factors are from § 1.6 Wood Residue Combustion in Boilers.

Table 2: PTE Assuming 50% TDF/Pellets Fuel and 50% Lower HAP Emissions From TDF/Pellets.

Emissions from all fuels (2,656B,800 MMBtu/year)		
Emission Factor Source: 2017-2018 stack tests		
HAP	Emission Factor	TPY
HCL	5.70E-03	7.57E+00
Arsenic	7.41E-07	9.84E-04
Lead	4.20E-06	5.58E-03
Manganese	2.91E-05	3.87E-02
Nickel	5.03E-07	6.68E-04
Emissions from all fuels (2,656,800 MMBtu/year)		
Emission Factor Source: LWEC Application		
Hydrogen fluoride	2.13E-03	2.83E+00
	Sum of tests and HF:	10.45

Emissions from Wood Fuels (1,328,400 MMBtu/year)			Emissions from TDF & pellets (1,328,400 MMBtu/year)		
Emission Factor Source: AP-42			Emission Factor Source: 50% of AP-42		
HAP	Emission Factor	TPY	HAP	Emission Factor	TPY
Formaldehyde	4.40E-03	2.92E+00	Formaldehyde	2.20E-03	1.46E+00
Benzene	4.20E-03	2.79E+00	Benzene	2.10E-03	1.39E+00
Styrene	1.90E-03	1.26E+00	Styrene	9.50E-04	6.31E-01
Acrolein	4.00E-03	2.66E+00	Acrolein	2.00E-03	1.33E+00
Antimony	7.90E-06	5.25E-03	Antimony	3.95E-06	2.62E-03
Beryllium	1.10E-06	7.31E-04	Beryllium	5.50E-07	3.65E-04
Cadmium	4.10E-06	2.72E-03	Cadmium	2.05E-06	1.36E-03
Chromium	2.10E-05	1.39E-02	Chromium	1.05E-05	6.97E-03
Cobalt	6.50E-06	4.32E-03	Cobalt	3.25E-06	2.16E-03
Mercury	3.50E-06	2.32E-03	Mercury	1.75E-06	1.16E-03
Phosphorus	2.74E-05	1.82E-02	Phosphorus	1.37E-05	9.10E-03
Selenium	2.80E-06	1.86E-03	Selenium	1.40E-06	9.30E-04
Acetaldehyde	8.30E-04	5.51E-01	Acetaldehyde	4.15E-04	2.76E-01
Acetophenone	3.20E-09	2.13E-06	Acetophenone	1.60E-09	1.06E-06
Carbon Tetrachloride	4.50E-05	2.99E-02	Carbon Tetrachloride	2.25E-05	1.49E-02
Chlorine	7.90E-04	5.25E-01	Chlorine	3.95E-04	2.62E-01
Chlorobenzene	3.30E-05	2.19E-02	Chlorobenzene	1.65E-05	1.10E-02
Chloroform	2.80E-05	1.86E-02	Chloroform	1.40E-05	9.30E-03
2,4-Dinitrophenol	1.80E-07	1.20E-04	2,4-Dinitrophenol	9.00E-08	5.98E-05
Bromomethane	1.50E-05	9.96E-03	Bromomethane	7.50E-06	4.98E-03
Chloromethane	2.30E-05	1.53E-02	Chloromethane	1.15E-05	7.64E-03
1,2-Dichloroethane	2.90E-05	1.93E-02	1,2-Dichloroethane	1.45E-05	9.63E-03
1,2-Dichloropropane	3.30E-05	2.19E-02	1,2-Dichloropropane	1.65E-05	1.10E-02
Ethylbenzene	3.10E-05	2.06E-02	Ethylbenzene	1.55E-05	1.03E-02

Napthalene	9.70E-05	6.44E-02	Napthalene	4.85E-05	3.22E-02
4-Nitrophenol	2.40E-07	1.59E-04	4-Nitrophenol	1.20E-07	7.97E-05
Pentachlorophenol	5.10E-08	3.39E-05	Pentachlorophenol	2.55E-08	1.69E-05
Phenol	5.10E-05	3.39E-02	Phenol	2.55E-05	1.69E-02
Propionaldehyde	6.10E-05	4.05E-02	Propionaldehyde	3.05E-05	2.03E-02
Toluene	9.20E-04	6.11E-01	Toluene	4.60E-04	3.06E-01
Tetrachloroethane	3.80E-05	2.52E-02	Tetrachloroethane	1.90E-05	1.26E-02
2,3,7,8-Tetrachlorodibenzo-p-dioxin	8.60E-12	5.71E-09	2,3,7,8-Tetrachlorodibenzo-p-dioxin	4.30E-12	2.86E-09
1,1,1-Trichloroethane	3.10E-05	2.06E-02	1,1,1-Trichloroethane	1.55E-05	1.03E-02
2,4,6-Trichlorophenol	2.20E-08	1.46E-05	2,4,6-Trichlorophenol	1.10E-08	7.31E-06
Vinyl Chloride	1.80E-05	1.20E-02	Vinyl Chloride	9.00E-06	5.98E-03
Acenaphthene	9.10E-07	6.04E-04	Acenaphthene	4.55E-07	3.02E-04
Acenapthylene	5.00E-06	3.32E-03	Acenapthylene	2.50E-06	1.66E-03
Anthracene	3.00E-06	1.99E-03	Anthracene	1.50E-06	9.96E-04
Benzo(a)anthracene	6.50E-08	4.32E-05	Benzo(a)anthracene	3.25E-08	2.16E-05
Benzo(a)pyrene	2.60E-06	1.73E-03	Benzo(a)pyrene	1.30E-06	8.63E-04
Benzo(g,h,i)perylene	1.00E-07	6.64E-05	Benzo(g,h,i)perylene	5.00E-08	3.32E-05
Benzo(l,k)fluoranthene	2.60E-09	1.73E-06	Benzo(l,k)fluoranthene	1.30E-09	8.63E-07
Benzo(k)fluoranthene	9.30E-08	6.18E-05	Benzo(k)fluoranthene	4.65E-08	3.09E-05
2-Chloronapthalene	1.60E-07	1.06E-04	2-Chloronapthalene	8.00E-08	5.31E-05
Chrysene	3.60E-08	2.39E-05	Chrysene	1.80E-08	1.20E-05
Dibenzo(a,h)anthracene	2.40E-09	1.59E-06	Dibenzo(a,h)anthracene	1.20E-09	7.97E-07
Fluoranthene	1.60E-06	1.06E-03	Fluoranthene	8.00E-07	5.31E-04
Fluorene	3.40E-06	2.26E-03	Fluorene	1.70E-06	1.13E-03
Indenol(1,2,3,c,d)pyrene	8.70E-08	5.78E-05	Indenol(1,2,3,c,d)pyrene	4.35E-08	2.89E-05
Monochlorobiphenyl	2.20E-10	1.46E-07	Monochlorobiphenyl	1.10E-10	7.31E-08
2-Methylnapthalene	1.60E-07	1.06E-04	2-Methylnapthalene	8.00E-08	5.31E-05
Phenathrene	7.00E-06	4.65E-03	Phenathrene	3.50E-06	2.32E-03
Pyrene	3.70E-06	2.46E-03	Pyrene	1.85E-06	1.23E-03
Perylene	5.20E-10	3.45E-07	Perylene	2.60E-10	1.73E-07
Decachlorobiphenyl	2.70E-10	1.79E-07	Decachlorobiphenyl	1.35E-10	8.97E-08
Dichlorobiphenyl	7.40E-10	4.92E-07	Dichlorobiphenyl	3.70E-10	2.46E-07
Heptachlorobial	6.60E-11	4.38E-08	Heptachlorobial	3.30E-11	2.19E-08
Hexachlorobiphenyl	5.50E-10	3.65E-07	Hexachlorobiphenyl	2.75E-10	1.83E-07
Pentachlorobiphenyl	1.20E-09	7.97E-07	Pentachlorobiphenyl	6.00E-10	3.99E-07
Trichlorobiphenyl	2.60E-09	1.73E-06	Trichlorobiphenyl	1.30E-09	8.63E-07
Tetrachlorobiphenyl	2.50E-09	1.66E-06	Tetrachlorobiphenyl	1.25E-09	8.30E-07
	Sum of wood emissions (tpy):	11.74		Sum of TDF and pellet emissions (tpy):	5.87
				Sum of all emissions (tpy):	28.06

Notes:

1. AP-42 emission factors are from § 1.6 Wood Residue Combustion in Boilers.
2. As discussed in our comments, we do not believe TDF and plastic pellets emit HAPs at lower rates than wood, let alone 50% lower, however we provide this scenario to demonstrate that LWEC's use of TDF and pellets cannot justify exempting LWEC from major source MACT.

Attachments to Comments by Environmental Integrity Project, et al. the Draft Permit to Install (Permit No. 128-18) Proposed for L'Anse Warden Electric Company, LLC (LWEC) by the Michigan Department of Environmental Quality (MDEQ).

Attachment A: Booth, Mary S., "Trees, Trash, and Toxics: How Biomass Energy Has Become the New Coal," Partnership for Policy Integrity (Apr. 2, 2014).

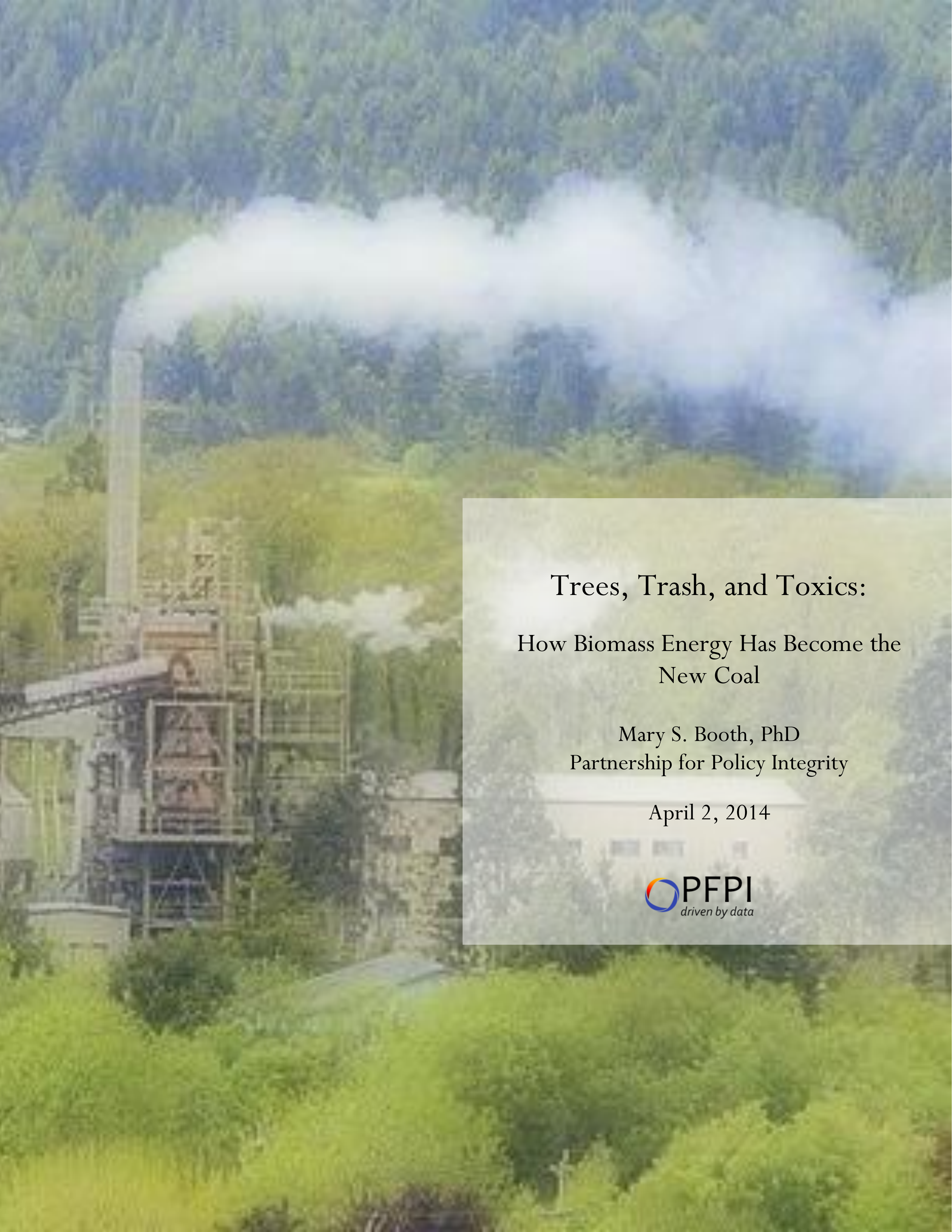
Attachment B: New Hampshire Department of Environmental Services, Permit Application Review Summary for DG Whitefield, LLC (Jan. 22, 2018).

Attachment C: Zhang, X. J., "Emissions of Volatile Organic Compounds from Large-Scale Incineration Plants," Journal of Environmental Science and Health, Part A, Vol. 33, Issue 2 (1998).

Attachment D: Barabad, Mona Loraine, *et al*., "Characteristics of Particulate Matter and Volatile Organic Compound Emissions from the Combustion of waste Vinyl," International Journal of Environmental Research and Public Health, (July 2, 2018).

Attachment E: Sewell, Melissa, *et al.*, "Optimising Dry Sorbent Injection Technology," World Cement (Apr. 2015).

Attachment A



Trees, Trash, and Toxics:

How Biomass Energy Has Become the New Coal

Mary S. Booth, PhD
Partnership for Policy Integrity

April 2, 2014

PFPI
driven by data

Trees, Trash, and Toxics:

How Biomass Energy Has Become the New Coal

Mary S. Booth, PhD
Partnership for Policy Integrity

April 2, 2014

PFPI gratefully acknowledges the support of The Heinz Endowments,
The Rockefeller Family Fund, The Threshold Foundation, and The Civil Society Institute
in supporting this work.

Contents

Cover photo from Jim Driscoll, "Blue Lake Power plant smokes out city." Eureka Times Standard. 4/30/2010. http://www.times-standard.com/localnews/ci_14990142

"District Air Pollution Control Officer Rick Martin said that an inspector was at the plant most of Thursday morning. Martin said the smoke was wood smoke and may be annoying, but it was not dangerous. "We don't really have the authority to shut them down unless it's an imminent danger to public health," Martin said, "and it's not a danger to public health."

For some, it was at least unbearable. Resident Curtis Thompson said that thick, brown smoke had been pouring out of the plant's stack since 7 a.m. Thursday, and it got bad enough that he drove his child out of the area."

Executive Summary

Highlights

The biomass power industry is undergoing a new surge of growth in the United States. While bioenergy has traditionally been used by certain sectors such as the paper-making industry, more than 70 new wood-burning plants have been built or are underway since 2005, and another 75 proposed and in various stages of development, fueled by renewable energy subsidies and federal tax credits. In most states, biomass power is subsidized along with solar and wind as green, renewable energy, and biomass plant developers routinely tell host communities that biomass power is "clean energy."

But this first-ever detailed analysis of the bioenergy industry reveals that the rebooted industry is still a major polluter. Comparison of permits from modern coal, biomass, and gas plants shows that a even the "cleanest" biomass plants can emit > 150% the nitrogen oxides, > 600% the volatile organic compounds, > 190% the particulate matter, and > 125% the carbon monoxide of a coal plant per megawatt-hour, although coal produces more sulfur dioxide (SO_2). Emissions from a biomass plant exceed those from a natural gas plant by more than 800% for every major pollutant.

Biomass power plants are also a danger to the climate, emitting nearly 50 percent more CO_2 per megawatt generated than the next biggest carbon polluter, coal. Emissions of CO_2 from biomass burning can theoretically be offset over time, but such offsets typically take decades to fully compensate for the CO_2 rapidly injected into the atmosphere during plant operation.

Compounding the problem, bioenergy facilities take advantage of gaping loopholes in the Clean Air Act and lax regulation by the EPA and state permitting agencies, which allow them to emit even more pollution. Electricity generation that worsens air pollution and climate change is not what the public expects for its scarce renewable energy dollars.

<u>Our examination of 88 air emissions permits from biomass power plants found:</u>

- Although biomass power plants emit more pollution than fossil fueled plants, biomass plants are given special treatment and are not held to the same emissions standards. A double standard written into the Clean Air Act allows biomass power plants to emit two and a half times more pollution (250 tons of a criteria pollutant) than a coal plant (where the threshold is 100 tons) before being considered a "major" source that triggers protective measures under the Clean Air Act's Prevention of Significant Deterioration (PSD) program – even though the pollutants, and their effects, are the same.

- Almost half of the 88 biomass facilities we analyzed avoided PSD permitting altogether by claiming they will be "synthetic minor" sources, even though in many cases their size indicates that they should be regulated as major sources of pollution, subject to the PSD program. Minor source permits are issued by the states and contain none of the protective measures required under federal PSD permitting. Despite the widespread use of this end-run around pollution restrictions, the EPA chooses not to review most state-issued minor source permits.

- The biomass power industry is increasingly burning contaminated fuels, blurring the lines between renewable energy that has been portrayed as "clean," and waste incineration. While most biomass power plants burn forest wood as fuel, the majority of the permits we reviewed also allowed burning waste wood, including construction and demolition debris. EPA rules allow biomass plants to emit more heavy metals and other hazardous air pollutants (HAPs) than both coal plants and waste incinerators, and again, the use of "synthetic minor" status is widespread, with facilities of all sizes claiming to be minor sources for HAPs with little support, verification, or proof. An EPA rollback on regulation that allows more contaminated wastes to be burned as biomass, rather than disposed of in waste incinerators with more restrictive emissions limits on air toxics, will only increase toxic emissions from the bioenergy industry.

Because of this perfect storm of lax regulation and regulatory rollbacks, biomass power plants marketed as "clean" to host communities are increasingly likely to emit toxic compounds like dioxins; heavy metals including lead, arsenic, and mercury; and even emerging contaminants, like phthalates, which are found in the "waste-derived" fuel products that are being approved under new EPA rules. Permissive emission standards for biomass plants mean that these pollutants can be emitted at higher levels than allowed from actual waste incinerators. As such, it is not a stretch to conclude that biomass plants being permitted throughout the country combine some of the worst emissions characteristics of coal-fired power plants and waste incinerators, all the while professing to be clean and green.

Detailed findings

Biomass power plants are disproportionately polluting not just because of their low efficiency (in converting heat to electrical output) and high emissions inherent in burning wood for energy, but also because the bioenergy industry exploits and actually depends on important loopholes in the Clean Air Act and its enforcement, loopholes that make bioenergy far more polluting than it would be if it were regulated like fossil fuels. Our review of 88 air permits of biomass power plants tabulated information on facility size, fuel use, pollution control technology, and allowable emissions. Some of the facility permits were issued under the Prevention of Significant Deterioration (PSD) program in the Clean Air Act, which requires "major sources" of pollution to reduce emissions by conducting a the Best Available Control Technology (BACT) analysis, and also requires facilities to conduct air quality modeling that assesses whether they will violate EPA's air quality standards and threaten health.

We contrasted permits that had gone through PSD with permits for "minor" sources, which are issued by the states and local agencies with little to no EPA (and public) oversight and contain none of the measures that PSD permits require to nominally protect air quality. We found that permits issued by states allowed biomass power plants to emit about twice as much pollution as plants with permits issued under the PSD program, and that state-issued minor source permits also dodged controls on high rates of emissions, for instance during plant startup and shutdown when pollution controls are frequently bypassed. Periods of intense emissions from facilities can present an elevated health risk because even short episodes of elevated air pollution are associated with acute adverse health effects such as asthma attacks, heart attacks, and stroke.

Loophole 1: Biomass plants can emit more pollution before triggering federal permitting

The biggest factor allowing bioenergy facilities to receive lax state-level minor source permits instead of PSD permits is a key loophole in the Clean Air Act that gives special treatment to biomass plants. While fossil-fueled power plants are considered major sources that are required to go through PSD if they emit 100 tons of a pollutant per year, a biomass plant is allowed to emit 250 tons of a pollutant before PSD permitting applies. The pollutants regulated by the law are the same – they have the same effect on health – but bioenergy plants are allowed to emit two and a half times the pollution of a fossil fueled plant before PSD permitting is triggered. As all but five (94 percent) of the 88 facilities for which we have permits in our database would emit more than 100 tons of a criteria pollutant, this single loophole is responsible for nearly doubling the amount of pollution that the emerging bioenergy industry is allowed to emit (because in general, minor source emissions limits are about twice the limits set in PSD permits).

The fix: Burning biomass for electricity produces as much or more of key pollutants as coal – so biomass should be regulated like coal. EPA has the authority to require that biomass plants be added to the list of pollution sources where PSD permitting is triggered at 100 tons. Biomass power plants are big, polluting facilities that emit hundreds to thousands of tons of pollution each year. They should be regulated accordingly.

Loophole 2: EPA's free pass for bioenergy CO_2 lets large power plants avoid regulation

When EPA began regulating CO_2 under the Clean Air Act, this provided an opportunity to reduce pollution from the bioenergy industry, had EPA chosen to take it. Under the implementation of the Tailoring Rule, if a facility was a major source for CO_2 (emitting 100,000 tons per year), PSD permitting would be triggered, including air quality modeling and a best available technology (BACT) analysis not just for CO_2, but criteria air pollutants as well. Since nearly every biomass power plant larger than about 8 MW has the potential to emit at least 100,000 tons of CO_2 per year, the decision by EPA to exempt bioenergy CO_2 emissions from regulation under the Clean Air Act for a period of three years greatly increased the potential for pollution from the emerging bioenergy industry. This exemption provides the majority of recently permitted biomass plants another means to avoid the protections afforded by PSD permitting. Although EPA's exemption for bioenergy CO_2 emissions was found to be unlawful by the U.S. Court of Appeals, the Agency has not implemented the Court's decision and reversed the exemption.

The fix: EPA should regulate bioenergy CO_2 now. Once in the PSD program, the best available control technology analysis stage provides an opportunity to discuss how biomass facilities can reduce their net emissions of CO_2.

Loophole 3: State regulators help biomass power plants avoid more protective permitting

One of the main loopholes allowing biomass plants to avoid PSD permitting is the claim of "synthetic" minor source status for nitrogen oxides and carbon monoxide. Facilities are granted a state-level minor source permit if they claim they will emit less than 250 tons of each pollutant per year, and thus get to escape PSD provisions that would limit pollution emissions, require use of best available control technology, and require air quality modeling to ensure a facility won't violate EPA's health standards for air pollution. In our database, the majority of facilities ranging in size from 6 MW to 60 MW opted for synthetic minor status, requiring the facility to emit less than 250 tons of CO, NOx, PM, and SO_2 per year to comply.

For small facilities, the 250 ton per year cap in a synthetic minor permit means they can emit far more pollution than necessary, given their size; for large plants, the cap requires they must meet unrealistically low emissions rates in order to emit less than 250 tons per year. In one case, where citizen petitioners protested a 24 MW plant in Hawaii that had been granted synthetic minor status, EPA agreed that the facility's emission limits were unenforceable and that the plant should likely be regulated as a major source. However, even though many other permits have been issued that appear to be even less enforceable than the Hawaii permit, EPA has opted to not get involved with most state-issued synthetic minor source permits, and as a result the permits continue to be issued with impunity. Currently, the majority of biomass power plants now proposed or under construction are still able to avoid even the minimal protections that PSD permitting provides.

The fix: If Loophole 1 were fixed, and PSD permitting was triggered at 100 tons of emissions, most biomass plants would have to go through PSD permitting. Likewise, if EPA implemented the U.S. Court of Appeals decision and regulated bioenergy CO_2 under the Clean Air Act, most plants would need to go through PSD permitting because most emit more than 100,000 tons of CO_2. Beyond those fixes, EPA should subject every power plant permit to federal oversight – especially those from states like Georgia, where regulators routinely issue synthetic minor source permits with the most minimal of conditions. It is going to take meaningful federal oversight to ensure that bioenergy permit contain emissions limits that are federally enforceable, as the Clean Air Act requires.

Loophole 4: Most biomass plants have no restrictions on hazardous air emissions

In the 88 bioenergy permits we examined, we found almost no accountability for emissions of hazardous air pollutants (HAPs), a group of especially toxic pollutants that includes hydrochloric acid, dioxins, carcinogens like benzene and formaldehyde, and heavy metals like arsenic, lead, and cadmium. Emissions of HAPs from biomass burners are barely regulated. A part of the Clean Air

Act known informally as the "boiler rule" sets the "Maximum Available Control Technology" (MACT) emissions standards for hydrochloric acid (HCl), as well as PM and CO, which serve as proxies for HAPs that are treated by EPA as being co-emitted with these pollutants. However, MACT standards for emissions of HCl, PM, and CO are only set for "major" sources of HAPs, which are defined as facilities that emit more than 10 tons per year of any one HAP or more than 25 tons of all HAPs per year. Minor sources that *claim* to emit below these thresholds are only required to meet an extremely lax standard for particulate matter – no emissions standards for HAPs are set directly. Thus, it's not surprising that most facilities claim to be minor sources for HAPs, no matter what their size.

The term "maximum available control technology" is in fact a profound misnomer, as the standards that are set for emissions under MACT are often far greater than what can be accomplished using pollution control technologies that are readily available today, especially for particulate matter. Under the biomass MACT rule, a major source biomass plant using a stoker boiler is allowed to emit more than 27 times the particulate matter of a coal boiler , and EPA rules allow most biomass plants to emit more than 10 times the particulate matter of a commercial and industrial waste incinerator. The rules for waste incinerators limit emissions of specific HAPs, including some heavy metals, but the rules for biomass plants do not contain any such limits. As more and more contaminated fuels are being burned as biomass, the lack of limits on emissions of HAPs is bound to increase emissions of the most toxic compounds from so-called "clean" bioenergy.

The fix: The EPA should make the so-called Maximum Available Control Technology standard meaningful, by setting standards as the Clean Air Act requires – standards that require the maximum degree of reduction of each HAP that is "achievable," considering cost and other statutory factors. At a minimum, without regard to cost, they must reflect the emission level that the cleanest sources have achieved – sources that are using emission control technologies that are effective and available, such as high-efficiency fabric filters that dramatically reduce particulate matter emissions. The biomass MACT should be made at least as protective as the standards for waste incinerators and coal boilers – especially given that facilities can be classified as biomass boilers even when burning up to 90% coal, and when burning highly contaminated wastes.

Loophole 5: The biomass industry lowballs estimates of toxic emissions to avoid regulation

In our database of 88 permits, 59% of facilities claimed they were minor ("area") sources for HAPs, including the **116 MW Gainesville Renewable Energy plant in Florida**. As with criteria pollutants, this non-major or area source designation is granted so easily by state permitting agencies, companies essentially have to volunteer to be regulated as major sources. Companies support their claim to be minor sources by using industry-supplied emission factors for HAPs, rather than EPA-sanctioned factors, to calculate their projected emissions during the permitting process. These industry-provided factors are in many cases orders of magnitude lower than EPA-sanctioned factors, but the organization that provides the emission factors, the National Council of Air and Stream Improvement (NCASI) will not divulge the data upon which they are based.

To test whether the industry emission factors for HAPs are valid, we compared the industry emission factor for hydrochloric acid, a HAP emitted in large quantities by biomass burning, with actual emissions data from 46 operating plants. We found that the industry factor significantly underestimates HCl emissions from real plants, suggesting that biomass power plants that use industry emission factors to claim minor source status for emissions of air toxics should probably in many cases be regulated as major sources.

The fix: The EPA and the states should require that HAPs emissions are estimated at the permitting stage based on emissions factors that are transparently derived, with a generous margin for error that assumes emissions are likely to spike at the very times (such as startup and shutdown) when they are least likely to be measured. Most facilities are probably major sources for HAPs, and should be regulated as such.

Loophole 6: Weak testing requirements mean air toxics limits aren't enforceable

We found that the lack of accountability for plants claiming to be "synthetic" minor sources for HAPs continues once plants are operating, because many permits only require minimal testing for hazardous air pollutants. Because emissions testing and enforceable limits don't even come into effect until several months after a facility starts operating, people living in the vicinity of a plant may have to undergo months of excessive and unknown pollution emissions while the facility ramps up. According to EPA, a permit that lacks testing requirements for HAPs is unenforceable, and thus invalid, but EPA has failed to exercise oversight over state-issued permits that claim area source status for HAPs.

The fix: A recent decision by EPA on a bioenergy facility in Hawaii makes it clear that if a facility wants to be regulated as a synthetic minor source (for criteria pollutants or HAPs) it must conduct testing that represents its true emissions, including during startup and shutdown. The permit must be written to require such testing, otherwise it is not federally enforceable, and is thus invalid. For limits to be truly enforceable, there should be ongoing monitoring with results revealed in real time, so that states and citizens can know when and if a facility is violating its permit.

Loophole 7: EPA rules blur the line between biomass facilities and incinerators

Lax regulation of biomass burners compared to waste incinerators is especially significant because new EPA rules make it easier to burn contaminated materials in biomass burners. EPA's "waste" rule allows garbage and other waste materials including plastics, tires and other wastes to be burned with minimal emissions controls and with no obligation to report emissions of heavy metals and other air toxics. The EPA admits that the new rules mean that wastes that are just as contaminated as the dirtiest coals available can be burned as biomass with no special provisions or disclosure. EPA has also announced that it is likely to remove any requirement that construction and demolition debris, which includes wood treated with copper-chromium-arsenate preservatives, be tested for contamination, trusting that industry "sorting" procedures will effectively remove contaminated material before it is burned as fuel. Since biomass plants do not have to meet any actual emissions standards for heavy metals, dioxins, or carcinogenic organic HAPs like benzene and formaldehyde, EPA's deregulation of contaminated fuels means that many facilities will be able to burn these materials with no accountability. Indeed, a large proportion of permits in our database granted permission for biomass plants to burn "waste" wood and other materials as fuel.

Under the waste rule, the EPA has also been granting "comfort letters" to companies that process garbage and industrial wastes into fuel products. Once EPA has signed off on these materials as "non-hazardous," they can be burned in a variety of boilers, even area source biomass boilers that are minimally regulated. An example is provided by SpecFUEL fuel cubes made by Waste Management. Contamination data on these cubes reveal high levels of fluorine, as well as phthalates, a chemical implicated in altering reproductive function that will soon be banned in the European Union. EPA approved SpecFUEL as a non-hazardous fuel product, enabling it to be burned in biomass plants that have no emission limits on air toxics.

The fix: The EPA needs to put people first – not the bioenergy industry, which has an inexhaustible appetite for contaminated fuels, particularly those that generate "tipping fees" for their disposal. The EPA should ensure that it does not create a loophole for unregulated incineration and that it protects public health by ensuring that all waste burners – including those that label themselves biomass units – meet the protective standards that Congress enacted for waste burning.

Overall, our assessment of the state of air permitting in the biomass power industry found that even as facilities routinely sell host communities on the idea a biomass plant is "clean" and safe, they appear to be misrepresenting actual emissions, while avoiding using the best pollution controls and performing air quality modeling. Our review found that EPA's rollback of regulation on biomass power combined with the loopholes inherent in the Clean Air Act leave communities unprotected from this growing and increasingly polluting industry.

Every permit we examined, even those that went through PSD, takes advantage of at least some of the Clean Air Act and regulatory loopholes we describe. From the 88 permits we included in the main analysis, the report provides detailed information on the following facilities:

Sierra Pacific, Anderson, CA
DTE Stockton, Stockton, CA
Plainfield Renewable Energy, Plainfield, CT
Montville Power, Uncasville, CT
Gainesville Renewable Energy, Gainesville, FL
Green Energy Partners, Lithonia, GA
North Star Jefferson, Wadley, GA
Piedmont Green Power, Barnesville, GA
Hu Honua, Pepe'ekeo, HI
ecoPower, Hazard, KY

Verso Bucksport, Bucksport, ME
Burgess Biopower, Berlin, NH
Lyonsdale Biomass, Lyons Falls, NY
ReEnergy Black River, Fort Drum, NY
Biogreen Sustainable Energy, La Pine, OR
Evergreen Community Power/United Corrstack, Reading, PA
Nacogdoches Power, Sacul, TX
EDF Allendale, Allendale, SC
Dominion Energy, Southampton, Altavista, and Hopewell, VA
Nippon Paper, Port Angeles, WA
Port Townsend Paper Company, Port Townsend, WA

Introduction: Biomass power, the renewable energy that pollutes

The biomass energy industry has always been highly polluting, as many communities where facilities are located can attest. Inherently high-emitting and poorly regulated, the industry's track record was revealed by a 2012 Wall Street Journal article reporting that nearly 80% of the facilities investigated by the paper had been cited by state or federal regulators for violating air pollution or water pollution standards at some time in the last five years.[1] Despite this history, however, biomass energy receives multiple renewable energy tax credits and subsidies. The availability of these incentives, which are worth millions of dollars per year to an individual facility, has driven a surge in biomass power plant proposals around the country (Figure 1), with more than 70 utility-scale wood-burning power facilities built or underway since 2005, and another 75 proposed and in various stages of development.[2] Some of these are new power plants, and some are old coal-fired power plants that are being re-fired with biomass, such as **Dominion Energy's three 51 MW coal plants in Virginia, the Altavista, Hopewell, and Southampton facilities**, which Dominion has rescued from mothballs to convert into "renewable energy generating assets."[3]

Figure 1. The biomass power industry is growing rapidly

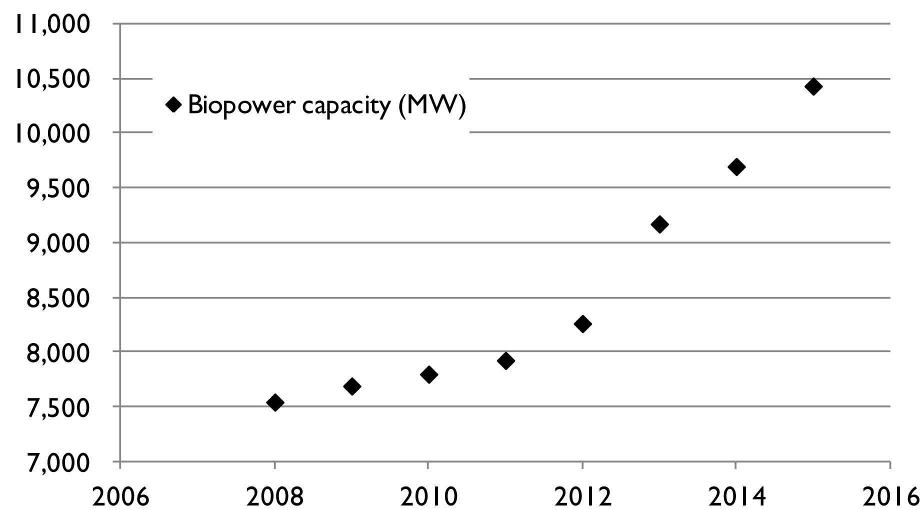


Figure 1. Actual and projected growth in the biopower industry from 2008 (built capacity for the 2008 industry from Energy Information Administration;[4] built capacity and proposed capacity from 2008 onwards from Forisk, Wood Bioenergy US database, December 2013). Not all proposed facilities will be built.

Building a biomass plant and generating electricity by burning wood is costly. According to the EPA, the levelized cost of generating electricity from biomass in 2011 dollars per megawatt-hour is \$97 - \$130, whereas the cost of onshore wind is \$70 - \$97 and the cost of natural gas combined

[1] Justin Schenk and Ianthe Dugan. Wood-fired plants generate violations. Wall Street Journal, July 23, 2012.
[2] Forisk, Wood Bioenergy US database, December, 2013
[3] Our report and letter to the Securities and Exchange Commission on bioenergy "greenwashing" by Dominion, Southern Company, and Covanta can be found at http://www.pfpi.net/investors-to-sec-please-scrutinize-bioenergy-claims
[4] Energy Information Administration. Existing generating units in the United States by State, Company, and Plant, as of December 31, 2008.

cycle technologies is $59 - $86, depending on the cost of gas.[5] Recently built and proposed biomass power plants provide examples of the costliness of biopower – for instance, the Southern Company's **116 MW (gross) Nacogdoches plant in Sacul, Texas**, the sister facility to the equally large **Gainesville Renewable Energy Center in Florida**, raised rates for Austin Power customers, and only operated for a few months before being paid to idle, as the utility was able to purchase cheaper power from wind and natural gas sources. The Gainesville plant raised rates for its regional customers, as well. In Kentucky, testimony from state hearings on the renewable power purchase agreement between Kentucky Power and the proposed **58 MW (net) ecoPower biomass plant in Hazard** indicates that electricity from the plant would raise the average residential electricity bill almost $125 per year in one of the poorest regions of the country, eastern Kentucky.[6]

While a single biomass plants can emit over a million tons of carbon dioxide a year, facilities aren't ever required to demonstrate these emissions are offset.

Additional costs for renewable power aren't necessarily unusual, but in the case of biomass power, developers and proponents justify extra expense by claiming that biomass power provides "clean" and "low carbon" baseload power, as if bioenergy were comparable to wind and solar. That such claims are misleading is increasingly apparent. Of late, the myth of bioenergy as "climate-friendly" is increasingly crumbling as new science and modeling demonstrate that wood-fired power plants increase CO_2 emissions over years to decades, even relative to fossil-fueled power plants.[7] The sheer amount of wood required by these facilities is an indication of their emissions, as forest wood is converted to CO_2 at about a 1:1 rate.[8] For instance, combined demand at the **three converted Dominion coal plants** will be about 2.4 million tons per year, with commensurate CO_2 emissions, and a single facility like the **116 MW Gainesville Renewable Energy plant in Florida** can emit over a million tons of CO_2 per year. The air permit for the **70 MW (gross) Burgess BioPower plant in Berlin, New Hampshire** states it will burn close to a million tons of trees a year, consuming "whole logs" at a rate of 113 tons per hour,[9] the equivalent of clear-cutting more than one acre of New Hampshire's forests every hour. While resequestration of the CO_2 emitted by this and other biomass plants being built around the country will require multiple decades, carbon offsets are never actually required to be obtained or demonstrated by these plants.

When policy-makers are given a chance to review the forest and greenhouse gas impacts from biomass energy, they may conclude that it is not worth the costs. For instance, the Vermont Public Service Board recently denied a certificate of "public good" to the **proposed 35 MW North**

[5] 40 CFR Parts 60, 70, 71, et al. Standards of Performance for Greenhouse Gas Emissions From New Stationary Sources: Electric Utility Generating Units; Proposed Rule. Federal Register Vol. 79, No. 5 Wednesday, January 8, 2014
[6] Commonwealth of Kentucky, before the Public Service Commission: Application of Kentucky Power concerning the renewable energy purchase agreement with ecoPower Generation-Hazard, LLC. Case No. 2013-00144. Volume I of court transcript.
[7] For a review, see PFPI report to the Securities and Exchange Commission on bioenergy "greenwashing," at http://www.pfpi.net/wp-content/uploads/2013/11/PFPI-report-to-SEC-on-bioenergy-Nov-20-2013.pdf
[8] Burning one ton of wood at 45% moisture content, considered an industry standard, emits 1.008 tons of CO_2.
[9] New Hampshire Department of Environmental Services. Final Temporary/NSR/PSD Air permit for Laidlaw Berlin BioPower, July 26, 2010.

Springfield Sustainable Energy wood burning plant in Vermont, stating that the project would interfere with the State's ability to meet statutory goals for reducing greenhouse gases and that "*the evidentiary record supports a finding that the Project would release as much as 448,714 tons of CO2e per year, and that sequestration of those greenhouse gases would not occur until future years, possibly not for decades, and would not occur at all in the case of forest-regeneration failures*."[10] In Massachusetts, new rules eliminate state renewable energy subsidies for low-efficiency utility-scale biomass plants, because their excessive and long-lasting net CO_2 emissions interfere with the state's goals of reducing CO_2 emissions from the power sector.[11]

Major loopholes in the Clean Air Act and its enforcement let biomass power plants emit more pollution than coal.

With the recent intense focus on greenhouse gas emissions from the bioenergy industry, however, less attention has been paid to emissions of conventional air pollutants and impacts on air quality. As for claims of carbon neutrality, which often rely on simply not counting CO_2 emissions from biomass power plants, claims that bioenergy is "clean" are usually not supportable. In fact, even bioenergy facilities employing modern controls like those used at coal plants are disproportionately polluting, primarily because burning wood is inherently polluting and biomass plants are very inefficient, extracting relatively little "useful" energy for the pollution they emit. However, also important to bioenergy pollution impacts is the fact that the preeminent law for protecting air quality in the United States, the Clean Air Act, contains major loopholes allowing biomass power plants to pollute more than fossil-fueled facilities. Compounding this, a pattern of lax enforcement and rollbacks on regulation by EPA and the states has widened these loopholes.

We wanted to develop a picture of the modern biomass power industry, how it is shaped by regulation, and how it is shaping regulation. To explore these questions, we collected recently issued air permits from biomass power plants, tabulating data on pollution controls, fuel use, permitted emissions, and other factors. We focused on recent permits because we assumed they would restrict pollution emissions to lower levels than typical for the bioenergy industry as a whole, which has traditionally been very polluting. Our analysis ultimately included 88 permits, which, when analyzed as a group, revealed systematic patterns that would not be apparent if permits were analyzed individually. What emerges from our analysis is a picture of an industry that despite loudly and continually proclaiming itself clean and green, is in many respects still one of the dirtiest corners of the energy industry, an industry where avoidance of pollution restrictions is tolerated, and even encouraged, by state and federal regulators. This report explains our findings.

---

[10] State of Vermont Public Service Board. Docket No. 7833 Petition of North Springfield Sustainable Energy Project LLC, for itself and as agent for Winstanley Enterprises, LLC, for a certificate of public good, pursuant to 30 V.S.A. Section 248, authorizing the installation and operation of a 25-35 MW wood-fired biomass electric generating facility to be located in the North Springfield Industrial Park in Springfield, Vermont, to be known as the "North Springfield Sustainable Energy Project" Order entered: 2/11/2014. Available at http://www.pfpi.net/wp-content/uploads/2014/02/7833-VT-PSB-on-NSSEP.pdf
[11] State of Massachusetts 225 CMR 14.00 – Renewable Energy Portfolio Standard, Class I. A summary of the regulations is available at http://www.mass.gov/eea/energy-utilities-clean-tech/renewable-energy/biomass/renewable-portfolio-standard-biomass-policy.html.

The physical reasons why bioenergy pollutes more than coal

Any power plant that burns fuel will emit numerous air pollutants, but there are two key factors that make biomass power plants emit as much or more pollution than modern coal or gas-fired power plants. First is the inherent composition of biomass fuels, including their chemical makeup and their energy content. Taking carbon as a main example, biomass power plants emit more CO_2 than fossil fueled plants (Table 1) because wood and other types of biomass are carbon-rich, but not particularly energy-rich, particularly relative to natural gas. This means that burning biomass releases more CO_2 per unit energy inherent in the fuel (pounds of CO_2 released per million Btu energy content, lb/MMBtu) than fossil fuels. Just as important, however, is that biomass power plants are much less efficient than gas and coal-fueled plants, in part because biomass fuels tend to have relatively high moisture content,[12] and it takes significant energy to boil off excess water before "useful" energy can be generated. Lower efficiency means that more fuel is required to generate a given amount of electrical energy from a biomass power plant, and burning more fuel releases more pollution.

Table 1. Biomass power plants emit more CO_2 than coal or gas plants

Technology	Fuel CO_2 emissions (lb/MMBtu heat input)	Facility efficiency	MMBtu required to produce one MWh	Lb CO_2 emitted per MWh
Gas combined cycle	117.1	45%	7.54	883
Gas steam turbine	117.1	33%	10.40	1,218
Coal steam turbine	206	34%	10.15	2,086
Biomass steam turbine	213	24%	14.22	3,029

Table 1: CO_2 emissions from biomass power plants versus fossil-fuel power plants.[13] The relatively low inherent energy density of biomass fuels, combined with the low efficiency of bioenergy plants, mean that per megawatt-hour (MWh), a biomass power plant emits about 145% the CO_2 of a coal plant, and 340% the CO_2 of a combined cycle natural gas plant.

The low efficiency of biopower plants increases their relative conventional pollutant emissions, as well.[14] To illustrate this, Table 2 gives an example of filterable particulate matter[15] emissions from a 500 MMBtu/hr coal boiler, and a biomass boiler of the same size, both with a permitted

[12] Typical moisture content for green wood chips, a very common fuel for bioenergy facilities, is around 45%, meaning by weight, the fuel is almost one-half water.

[13] Fuel CO_2 per heat content data are from EIA, Electric Power Annual, 2009: Carbon Dioxide Uncontrolled Emission Factors. Efficiency for fossil fuel facilities calculated using EIA heat rate data (http://www.eia.gov/cneaf/electricity/epa/epat5p4.html); biomass efficiency value is common average value for utility-scale facilities; however, the smaller the facility, the lower the efficiency.

[14] This fact is often obscured because emissions of conventional pollutants are often expressed on a "heat input" basis (pounds of pollutant per million Btu of heat input to the boiler, lb/MMBtu), rather than on an "output" basis, as is done for CO_2 (pounds of CO_2 per megawatt-hour, lb/MWh). One important exception is emission rates set for coal plants greater than 25 MW in size, which (as discussed below) are regulated under EPA's "Electric Generating Unit" (EGU) rules with rates that are set on a pounds per megawatt-hour basis.

[15] Filterable particulate matter is the portion of particulate matter that can be largely (but not completely) controlled by a fabric filter or an electrostatic precipitator.

emissions level of 0.012 lb/MMBtu,[16] a common value seen in many biomass facility air permits. Both facilities would emit 26 tons of particulate matter per year, calculated on a heat input basis, but because the biomass plant doesn't produce as much energy as the coal plant, it emits 41.6% more particulate matter on an electrical output basis, expressed as pounds of pollution per megawatt-hour (MWh) of energy.

Table 2: Biomass power's lower efficiency increases particulate matter emissions

Fuel	Boiler size (MMBtu/hr)	Efficiency	MMBtu heat input/yr	PM rate (lb/MMBtu)	Tons PM/yr	MWh/yr	lb PM/MWh
Biomass	500	24%	4,380,000	0.012	26	307,999	0.17
Coal	500	33%	4,380,000	0.012	26	423,498	0.12

Table 2: The lower efficiency of biomass power plants increases their emissions per megawatt-hour.

The inherently polluting nature of bioenergy affects how air permits are written, and how much pollution a biomass plant is allowed to emit. Figure 2 shows allowable emissions on an output basis (lb/MWh) from three air permits, a coal plant, a biomass plant, and a natural gas plant.

Figure 2: Even with modern emissions controls, biomass power plants emit more pollution than coal or gas

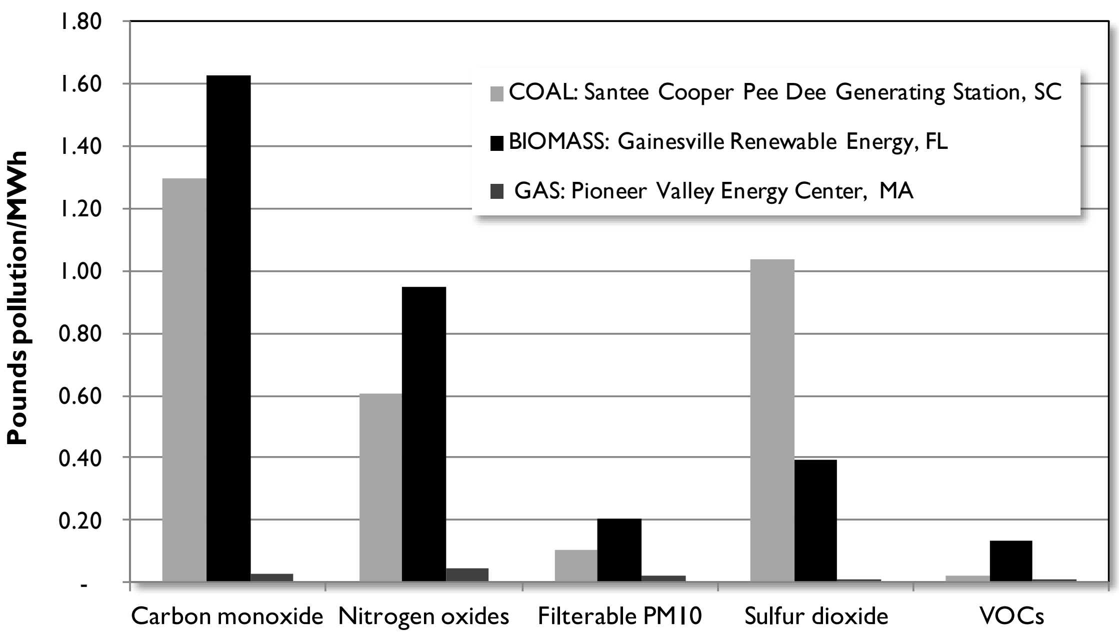


Figure 2. Allowable emission rates (in pounds per megawatt-hour) from three recently issued permits.[17]

[16] Lb/MMBtu = pounds of pollution emitted per unit boiler capacity in million Btu per hour

[17] South Carolina Bureau of Air Quality. December 16, 2008. PSD, NSPS (40CFR60), NESHAP (40CFR63) Construction Permit for Santee Cooper Pee Dee Generating Station (1,320 MW, coal). Florida Department of Environmental Protection. December 28, 2010. Final air construction permit for Gainesville Renewable Energy Center (100 MW, biomass). Massachusetts Department of Environmental Protection. June, 2010. Conditional permit to construct issued to Pioneer Valley Energy Center (431 MW, gas).

All three facilities went through a Best Available Control Technology analysis (BACT, described further below), meaning that their emissions are relatively well-controlled compared to other facilities of their type. However, emissions from the biomass plant exceed those from the fossil fueled plants for all pollutants except sulfur dioxide, for which biomass emissions exceed gas, but not coal. Relative to the coal plant and the gas plant, respectively, allowable emissions at the biomass plant are126% and 5639% for carbon monoxide; 157% and 2015% for nitrogen oxides; 197% and 863% for filterable PM_{10}; 38% and 3514% for sulfur dioxide; and 655% and 1535% for volatile organic compounds.[18]

Even when a biomass plant is using best available control technology, emissions of key pollutants exceed those of modern coal and gas plants.

How the Clean Air Act regulates pollution from power plants

The Clean Air Act is the main federal law regulating emissions from power plants and other stationary source facilities. While the Clean Air Act can regulate any pollutant, the main pollutants it governs are the so-called "criteria" pollutants (particulate matter, carbon monoxide, nitrogen oxides, sulfur dioxide, ozone, and lead); hazardous air pollutants (HAPs), the group of 187+ pollutants that are considered especially toxic by EPA; and greenhouse gases, including CO_2.

A key regulatory tool in the Clean Air Act is the New Source Review (NSR) process, which requires new or modified stationary sources like power plants to obtain a preconstruction permit that sets allowable pollution emission rates and other conditions of operation.[19] The restrictiveness of these permits varies, based on how much pollution a facility is anticipated to emit (larger sources are regulated more tightly than smaller sources) and the existing air quality in the area (facilities located where air pollution already exceeds EPA's health standards are more tightly regulated).

Preconstruction permits can be issued according to one of three permitting subprograms under New Source Review:

- The "Prevention of Significant Deterioration" (PSD) program applies to facilities of a certain size located in areas that meet the National Ambient Air Quality Standards (NAAQS), the health standards that EPA sets for the criteria air pollutants PM, CO, NO_x, SO_2, ozone, and lead. While state air permitting agencies write these permits, they must do so in accordance with EPA regulations, and EPA and the public may provide comments and input on certain permits.

[18] A potential but currently suspended permit revision filed in February 2014 seeks to regulate the facility under the major source boiler rule. If the plant is re-permitted as a major source for HAPs, allowable filterable PM emissions will decrease under the major source MACT for bubbling fluidized bed boilers, from of 0.015 lb/MMBtu to 0.0098 lb/MMBtu (Gainesville Renewable Energy Center. Initial Title V air operation permit application filed with Florida Department of Environmental Protection. February 10, 2014). This change would reduce permitted emissions from 89 tons to 58 tons of filterable PM per year, but filterable PM emissions per MWh would still be 128% those from the coal plant.

[19] New source review permits are "preconstruction permits," and differ from Title V permits, which set out the terms by which facilities are expected to operate and meet the emissions limits specified in the NSR permit.

- The "Nonattainment New Source Review" (NNSR) program applies in areas where pollution exceeds the NAAQS. Permits issued under this program may also receive EPA and public review like the PSD permits above.
- The "Minor Source" program applies to facilities that are anticipated to not emit enough pollution to be included under the PSD or NNSR programs. Unlike PSD and NNSR permits, minor source permits are expected to meet certain minimal Clean Air Act requirements but are otherwise solely administered by local or state-level air permitting agencies with little if any EPA or public oversight.

As we demonstrate below, facilities that go through the PSD and NNSR process tend to have much lower allowable emissions than minor source facilities that simply get a permit from the state.[20] The difference can mean biomass power plants that receive state-issued minor source permits are allowed to emit far more pollution than they would be otherwise if they were held to more rigorous standards. This permitting scheme clearly incentivizes bioenergy facilities to seek "minor source" status in order to avoid more stringent limits.

The commonsense components of a federal air permit

While permits issued under the PSD or NNSR program may sound like they could be quite rigorous, in fact, the requirements of the programs are merely commonsense, including measures to reduce pollution as by using effective emission controls and operating the plant properly, air quality simulation modeling to make sure that a facility's emissions won't increase air pollution above EPA's health thresholds, and provisions to allow citizen involvement and ensure environmental damage is minimized.

BACT Analysis. Under the PSD program, major sources undergo a Best Available Control Technology (BACT) analysis to determine the most effective emissions controls for each pollutant.[21] If a new facility exceeds the threshold for one pollutant, then it required to go through a BACT analysis for *all* criteria pollutants that exceed a specified emissions threshold. The BACT analysis doesn't truly require the "best" control technology, however, because a facility can reject technologies as being too expensive. Nonetheless, facilities that go through BACT analyses tend to have lower allowable emissions than facilities that don't. BACT is a moving target, because as permits are written with lower emission rates, achievable via better and improved controls, these rates in turn become the new BACT standard for subsequent facilities.

Under the NNSR program, when a power plant is being built in a location that already has an acknowledged air quality problem, known as a "non-attainment" region, facilities are

[20] Certain states have strong air permitting requirements that meet and even exceed what would be required under the PSD process. For instance, both Massachusetts and Vermont have fairly rigorous state-level air permitting requirements.
[21] In a BACT analysis, the applicant and state must consider, among other things, clean fuels and environmental impacts of the source permit issuing authorities must consider "alternatives" to the proposed project in addition to a proposed project's air quality and other environmental impacts. BACT permitting does allow cost considerations. LAER does not.

supposed to use the technology that delivers the Lowest Achievable Emission Rate (LAER). Unlike BACT, a LAER analysis is not supposed to consider technology cost. Facilities being built in non-attainment regions are also required to obtain emission offsets for pollutants that exceed the NAAQS.

Air Quality Modeling. Under PSD, major source facilities have to undergo air quality modeling, in which a computer model is used to simulate dispersion of pollution from a facility, adding the facility's emissions to background air pollution levels to ascertain how much the plant will increase local air pollution. Emissions from nearby facilities are also included in this analysis. The modeling usually assesses two emission rates for each pollutant – a "long term" average rate (often calculated over 30 days) to determine whether a facility will cause local air pollution to exceed the annual NAAQS, and a short-term emission rate (the concentration over a one- or three-hour period), to determine whether a plant will cause an exceedance of the short term/hourly NAAQS.[22]

Regulation of $PM_{2.5}$. The PSD program requires permit applicants to model how emissions of both filterable PM and condensable PM will affect ambient $PM_{2.5}$ levels. In contrast, plants that don't go though PSD are typically only held to the New Source Performance Standard (NSPS) for PM emissions, which simply requires that filterable PM_{10} emissions not exceed 0.03 lb/MMBtu, or even less stringent standards for existing facilities. The NSPS standards do not apply during facility startup and shutdown.

Public Involvement. An important aspect of the PSD process is that the state agency issuing the air permit is required to hold public informational meetings about the facility's impacts, not only on air quality, but on other aspects of the environment as well. The permit-issuing authority is required to consider comments submitted during the permit-approval process, which may include arguments that the facility is not needed at all. In contrast, minor sources that don't go through the PSD process simply get a state-issued permit and there is no requirement for public involvement.

EPA Oversight. While EPA will sometimes review and comment on PSD permits, helping to improve them, the Agency generally ignores state-issued minor source permits, unless asked to intervene. However, all permits, whether PSD permits or minor source permits issued by the state, are supposed to comply with federal New Source Performance Standards (NSPS), maximum emissions rates set for certain pollutants, and the National Emission Standards for Hazardous Air Pollutants (NESHAP), discussed below. All permits must be "federally enforceable" to be valid.

[22] Short term standards are generally designed to protect against acute effects of exposure, while longer-term standards are designed to protect against health effects that can result from cumulative, long-term exposure to even lower levels of pollution. Some pollutants have both annual and short-term standards, because they can be both acutely and chronically harmful at different levels. Health-based (or "primary") NAAQS tend to be based on health effects identified in both laboratory and epidemiological studies, and are subject to several rounds of review (including by the Clean Air Science Advisory Committee, comprised of leading scientists in the field).

Going through a BACT or LAER analysis, along with air quality modeling, does not ensure that a facility will not degrade air quality. In most cases, pollution emissions from federally permitted facilities are still large, and often, the provisions of an air permitting program do relatively little to reduce emissions. For instance, the **54 MW (gross) DTE Stockton biomass plant in Stockton, California**, is an old coal plant that has been refurbished to burn biomass. As a coal plant, this facility stopped operation in 2009. It is located in a highly polluted area, designated as being in "extreme" non-attainment for ozone (making the major source threshold that triggers PSD permitting 25 tons, rather than 250 tons) and non-attainment for $PM_{2.5}$.[23] Emissions from the new DTE biomass boiler triggered offset requirements for emissions of NOx, SOx, PM_{10}, and VOCs, but rather than being compelled to obtain new offsets, the facility was allowed to treat the cessation (in 2009) of previous allowable emissions from the coal plant as mostly "offsetting" biopower emissions of 107 tons of NOx, 58 tons of PM_{10}, 70 tons of SO_2, and 25 tons of VOCs – "mostly," because while the plant's emissions of SO_2 decreased with the transition to biomass from coal, emissions of PM and VOCs increased.[24] Offsets math notwithstanding, this biomass power plant thus represents what is essentially a *new* source of pollution in an already polluted region, one that is cheerfully announced by the company in a press release as a "green energy plant."[25]

What 88 air permits say about regulation of the biomass power industry

Due to the subsidies and tax incentives available for bioenergy, a large number of air permits for biomass power plants have been issued in recent years. We collected 88 preconstruction and Title V permits[26] from biomass power plants proposed in recent years and entered key data into a common database, assembling information on each facility's boiler technology, fuel use, pollution control technologies, and allowable emissions. Using this dataset, we were able to examine how much pollution facilities are being allowed to emit under PSD/NNSR permits versus state-level minor source permits, and how the biomass power industry is exploiting loopholes in the Clean Air Act and its enforcement.

We used a subset of 46 permits for new facilities to graphically compare how modern bioenergy facilities propose to control emissions, and how allowable emissions differ at "major" and "minor" source facilities. This subset included the permits we had for "greenfield" facilities that had clearly either gone through PSD permitting with a BACT analysis, or which had received minor source permits. The subset excluded facilities where an old coal plant is being retooled to burn biomass, where in some cases, an existing permit was modified but contains relic provisions from when the plant burned coal. As new facilities, the PSD and non-PSD groups can be assumed to have had equivalent opportunities to optimize facility design and adopt modern pollution controls.

---

[23] EPA listings for county attainment status are at http://www.epa.gov/airquality/greenbook/ancl3.html

[24] San Joaquin Valley Air Pollution Control District. Authority to Construct Application Review, Biomass-Fired Power Plant – for DTE Stockton, LLC. April 28, 2011. The offsets calculations occur in Table 18.

[25] The company's March 13, 2014 press release is available at online.wsj.com/article/PR-CO-20140313-912116.html

[26] Some permits are for facilities that have subsequently been cancelled; some are for facilities still pending; some are for facilities that have been built.

Bioenergy emissions of criteria pollutants and CO_2: Clean Air Act loopholes

Beyond the inherently polluting nature of biomass power, key loopholes in the Clean Air Act allow biomass plants to be less regulated than coal and gas plants. Some of these loopholes are baked in to the Clean Air Act, while others are the result of recent regulatory and policy decisions by EPA. Our overview first examines loopholes affecting emissions of criteria pollutants; in the second part of the report, we discuss loopholes for emissions of hazardous air pollutants (HAPs) and loopholes that allow contaminated wastes to be reclassified as "non-waste fuel products" that can be burned in biomass plants.

Loophole 1: Biomass plants can emit more pollution before triggering federal permitting

One of the most significant loopholes for bioenergy in the Clean Air Act is the triggering threshold for consideration as a "major source" for criteria pollutants. Whereas new fossil fuel plants are considered to be a major source that triggers PSD permitting if they emit more than 100 tons of a criteria pollutant per year, bioenergy plants escape PSD unless they emit at least 250 tons of a criteria pollutant per year.[27] As we demonstrate below, biomass plants that avoid PSD permitting are allowed to emit about twice as much pollution as plants that go through PSD, and lack other protections afforded by the PSD program. Compared to coal plants and natural gas plants that are required to go through PSD if they emit 100 tons of a pollutant, biomass power plants that avoid PSD are very lightly regulated, even though the types of pollution emitted, and consequent health effects, are the same. As all but five of the 88 facilities for which we have permits in our database would emit more than 100 tons of a criteria pollutant, it appears that this single loophole, which is a relic of Clean Air Act implementation decisions made in the 1970's, is responsible for nearly doubling the amount of pollution that the emerging bioenergy industry is allowed to emit. The Clean Air Act allows the EPA Administrator to add new industries to the list of sources where the 100 ton threshold triggers PSD permitting. Given the current growth in the bioenergy industry and its potential to pollute, adding biomass power plants to that list would represent sound public policy.

Under the Clean Air Act, biomass power plants are allowed to emit 250% the pollution of a coal plant before more protective permitting is triggered.

Loophole 2: EPA's free pass for bioenergy CO_2 lets large power plants avoid regulation

The tendency for bioenergy facilities to avoid PSD permitting has been exacerbated and enabled by EPA's decision to exempt bioenergy CO_2 from regulation under the Clean Air Act. Initially, when

[27] PSD is also triggered for both new plants and existing plants undergoing "major modifications," when those modifications would cause emissions to increase by more than a certain amount. The triggering thresholds for existing facilities are the same for biomass and fossil-fueled plants.

EPA began regulating CO_2 under the Tailoring Rule in early 2011,[28] bioenergy facilities were included under the rule along with fossil-fueled plants. At that time, if a wood-burning power plant was a major source for CO_2 (emitting over 100,000 tons of CO_2 per year), *and* it was a major source for a criteria pollutant (emitting over 250 tons per year) then PSD permitting was triggered, and the facility would go through a BACT analysis for CO_2, as well as for other pollutants. However, in July of 2011, when "Step II" of the Tailoring Rule was implemented and facilities could be deemed major sources for PSD on the basis of their CO_2 emissions alone,[29] EPA bowed to pressure from the bioenergy industry and exempted bioenergy facilities from the rule for a period of three years, pending study of how biogenic CO_2 emissions should be regulated. It is important to note that although the EPA exemption of bioenergy CO_2 from counting toward PSD applicability was generally based on the assumption that greenhouse gas emissions would be offset, not one of the permits we reviewed for this report actually required demonstration that emissions be offset.

EPA's exemption for bioenergy CO_2 under the Clean Air Act has allowed many facilities to avoid requirements for more protective emissions controls.

Biomass power companies are applying for air permits at an unprecedented rate, thus the exemption of biogenic CO_2 from regulation prevented pollution restrictions from being placed on the industry just when it most needed oversight. Nearly every plant proposed in recent years is a major source for CO_2, because almost all are larger than 8 MW, which is the size of plant with a potential to emit (PTE)[30] more than 100,000 tons of CO_2. Burning one ton of green wood chips emits about one ton of CO_2, thus CO_2 emissions from fuel burned at a typical plant, such as the 49 MW plant in Figure 3, are many hundreds of thousands of tons per year, far exceeding the major source threshold. Thus, had EPA not granted the exemption, most biomass power plants would be pulled into the PSD permitting program on the basis of their CO_2 emissions alone, and would go through a BACT analysis for both

Figure 3. The massive woodchip fuel pile at a 49-MW bioenergy plant in California. (Photo credit: NREL)

[28] The Tailoring Rule set emission thresholds that trigger a facility being considered a major source for greenhouse gases. Because greenhouse gases are emitted in far larger quantities than criteria pollutants, the 250 ton threshold that applies for criteria pollutants was not a practical limit, thus, the triggering thresholds were "tailored" to adapt the regulations for greenhouse gas emissions. See http://www.epa.gov/nsr/ghgpermitting.html

[29] Under the Step II regulations, CO_2 received the same treatment as other pollutants – if a facility was "major for one," in this case CO_2, it would be "major for all," triggering a BACT analysis for all pollutants.

[30] "*Potential to emit* means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable." 40 C.F.R. § 52.21 (b)(4).

CO_2 and conventional air pollutants, as well as undergoing air quality impacts modeling. Importantly, the group of bioenergy facilities thus affected would include not only the facilities that received preconstruction permits after July 1, 2011, when Step II of the Tailoring Rule came into effect, but also those facilities that had previously received a permit but had not yet started construction by July 1. The CO_2 exemption has thus allowed most facilities with permits issued in recent years to avoid PSD permitting. No coincidence, a flurry of state-level permits were issued just before the July 1 2011 deadline when Step II permitting was to take effect, even though EPA had indicated it would grant the exemption. Of the permits we reviewed that were issued in 2011, 14 were issued before July 1, with 8 of those issued in June. A total of 6 were issued after June.

A federal court found that EPA's exemption for biomass CO_2 was unlawful, and that bioenergy emissions should count under Clean Air Act permitting

Following EPA's exemption for bioenergy CO_2, the Center for Biological Diversity with other environmental groups sued the Agency, challenging the action. In July 2013, the U.S. Court of Appeals for the District of Columbia Circuit ruled in favor of the groups, determining that EPA had unlawfully exempted bioenergy from regulation under the Clean Air Act.[31] However, rather than issuing a mandate to EPA to reverse the exemption, the court granted a long delay to the industry litigants that had joined with EPA to defend the exemption, extending the deadline for filing a petition for reconsideration or rehearing by all of the Court's active judges.[32] The three-year exemption in any case lapses in July 2014, at which point EPA will need to take some action on how biogenic CO_2 will be regulated. In the meantime, it is unclear whether the court will issue a mandate that directs EPA to reverse its policy and officially declare that facilities that are major sources for CO_2 need to go through PSD, although in any case EPA could take action without waiting for the court's mandate. When and if this happens, some bioenergy facility permits that were issued under the exemption could be re-opened and re-permitted through the PSD process. Meanwhile, there are about 60 bioenergy facilities currently planned or under construction in the U.S. [33] that are over 8 MW in capacity, the approximate threshold for a major source for CO_2 emissions. By allowing these facilities to escape PSD permitting, EPA's exemption for bioenergy CO_2 regulation allows the bioenergy capacity "in the pipeline" to be far more polluting than it needs to be.

Loophole 3: State regulators help biomass power plants avoid more protective permitting

Bioenergy developers usually want to avoid going through the PSD process, because conducting a BACT analysis and air quality impacts modeling, determining effective pollution controls, and dealing with public involvement can increase the risk that a high-emitting facility will face more

[31] *Center for Biological Diversity v. EPA*, D.C. Cir. No. 11-1101, July 12, 2013

[32] The D.C. Circuit Court essentially refrained from acting while a number of industry challenges to the Tailoring Rule itself are proceeding in the U.S. Supreme Court. Those challenges—which will determine whether the PSD program applies to greenhouse gases as a whole, not just biogenic CO_2—are being heard by the Supreme Court in February, with a decision expected in mid-2014.

[33] Forisk, Wood Bioenergy US database, December, 2013

scrutiny and questions. State permitting agencies usually help bioenergy developers avoid PSD permitting, and "PSD avoidance" is a common phrase encountered in bioenergy air permits.

A facility's status as a major or minor source is determined by its **potential to emit (PTE).** This is the number of tons of a pollutant that the facility will emit if it is operated year-round, at full boiler capacity. It is calculated as

Equation 1

$$\text{PTE (tons per year)} = \text{boiler capacity}\left(\frac{\text{MMBtu}}{\text{hr}}\right) * \text{emission rate}\left(\frac{\text{lb}}{\text{MMBtu}}\right) * 8{,}760\text{ hrs} \div 2{,}000\left(\frac{\text{lb}}{\text{ton}}\right)$$

To avoid PSD permitting, the biomass industry avails itself of another loophole in the Clean Air Act known as the "synthetic" minor source provision, whereby if facility caps its emissions below 250 tons of each criteria pollutant per year, it can avoid the PSD permitting process and its requirements for a BACT analysis, air quality modeling, and public involvement. States routinely allow and even encourage facilities to avoid PSD permitting by issuing air permits that cap emissions just below 250 tons – even, sometimes, when the facility's potential to emit exceeds 250 tons. Such permits frequently include credulity-straining provisions that limit a facility's emissions to 249 tons of a pollutant, as we discuss below (see Tables 4 and 5).

"Synthetic minor" facilities avoid setting emissions rates, conducting air quality modeling, or using best available control technology.

The 250-ton cap for emissions in a synthetic minor permit is supposed to include *all* annual emissions from the facility, including startup and shutdown emissions from the boiler and emissions from other sources, such as emergency generators. However, it is rare that a synthetic minor permit does a full accounting of all the emissions at a facility, or includes enforceable limits that can truly constrain facility-wide emissions once the plant is operating. As we discuss below, such permits unenforceable and thus illegal under the Clean Air Act, but because the EPA rarely reviews state-issued permits, federal enforcement is rare.

For a number of the synthetic minor permits we reviewed, the biomass boilers alone have a PTE that exceeds 250 tons of a criteria pollutant, given the size of the unit and the ability to control emissions. This would suggest that the 250-ton-per-year caps, which are required by federal law to be "federally and practically enforceable,"[34] for instance by limiting the number of hours in a year that a facility can operate, are in some (or perhaps many) cases unrealistic. In fact, in our review of tens of biomass power plant permits, very few of the synthetic minor sources we found had any limits on hours of operation, or any other limitations. Instead, state air permitting agencies simply require facilities to install continuous emissions monitors (CEMs) that track how much pollution is produced, and to report these emissions, as proof that they are emitting less than 250 tons per year of each pollutant. The presence of a CEMs has been accepted as sufficient assurance that the caps

[34] The Clean Air Act requires that "limitations, controls and requirements in operating permits are quantifiable and otherwise enforceable as a practical matter" 60 Fed. Reg. 45049 (August 30, 1995).

are federally and practically enforceable – even when it is likely that the boiler will have difficulty meeting the 250 ton per year cap, and even though a CEMs on a biomass boiler only measures emissions from that unit, and not the facility-wide emissions that are supposed to be included under the cap.

The frequent use of the synthetic minor source loophole has important implications for how biomass power plants operate, and thus for air quality. While the total tons of pollution that a plant emits annually is obviously one index of its impact on air quality, just as important is the short-term *rate* at which that pollution is emitted – the actual amount per hour. Permits issued under PSD set "short-term" (1 - 3 hrs) and "long-term" emissions limits (often, rolling 30-day averages that represent annual emissions). The PSD process also requires modeling *before* a plant is built to predict whether the plant will cause violations of the short-term and annual NAAQS. Permits that simply cap emissions below 250 tons don't contain these protective measures.

The absence of short-term emissions rates in a synthetic minor source permit threatens air quality

The absence of short-term emission limits in synthetic minor source permits is a threat to air quality. Biomass power plants are notorious for producing large slugs of air pollution over short periods, because the fuels they burn, which include wood, agricultural wastes, and wastes from the paper-making industry, are inconsistent in composition and moisture content, decreasing combustion efficiency and increasing emissions. How a plant is operated – at steady state, or in a "cycling" mode, ramping up and down periodically – also affects emissions. Most PSD air permits and a few state-level permits recognize this, setting different emissions standards for startup and shutdown versus steady-state combustion. For instance, the permit for the proposed **67 MW (gross) Greenville Power plant in Greenville, Texas**[35] states that the electrostatic precipitator for controlling PM, the selective catalytic reduction (SCR) system for controlling NOx, and the catalytic oxidation system for controlling CO and VOCs "*may not be fully operational if the boiler is operating at less than 75% of base load*."[36] The Greenville permit specifies that emission rates from the Greenville facility during startup and shutdown[37] (Table 3) can exceed those during normal operations – for instance, filterable PM emissions increase by more than 700%, compared to steady-state operation. Startup and shutdown events can take 12 - 24 hours, meaning that the total amount of pollution emitted over these periods can be significant.

However, synthetic minor permits generally don't contain limits on startup or shutdown emissions at all – importantly, the only emissions rate requirement that synthetic minor sources do have to meet, the New Source Performance Standard for new facilities that sets filterable PM standard at 0.03 lb/MMBtu, specifically exempts facilities during startup and shutdown.

---

[35] Maximum allowable emission rates for Permit Number 9322. Texas Commission on Environmental Quality, December 31, 2010.
[36] Construction permit source analysis and technical review for Greenville Energy, LLC. Texas Commission on Environmental Quality.
[37] Ibid.

Table 3: Emissions increase significantly during startup/shutdown

Pollutant	Normal Emissions (lb/hr)	Maintenance, Startup and Shutdown Emissions (MSS)	MSS Emissions as % of Normal Emissions
NO_x	54	54	100%
CO	54	96.8	179%
VOC	6.1	16.1	264%
PM_{10}	22.1	168.8	764%
SO_2	7.9	5.6	71%
HCl	1.53	7.65	500%
H_2SO_4	0.2	0.4	200%
NH_3	10.7	--	--

Table 3. Allowable emission for the Greenville bioenergy facility in Texas. Emissions increase significantly during non-steady state operation.

The fact that synthetic minor sources aren't required to do air quality modeling means that the effect of these short-term surges in pollutant emissions on air quality and health can't be known. Rather than requiring facilities to control emissions during these periods, permitting agencies simply rely on facilities to do the right thing to control pollution. For instance, in response to a comment expressing concerns about the absence of controls during startup and shutdown at the proposed **25 MW North Star Jefferson wood-tire burner in Wadley, Georgia,** the Georgia Air Protection Branch staff explained, "*During startup and shutdown phases, the control devices are not able to achieve desired control efficiency due to operational limitations of the systems. The annual PSD Avoidance limits for CO, SO_2, NOx and GHG include emissions during all periods of operation including startup, shutdown and malfunction; thus, there is incentive for facility to begin operation of the control devices as soon as possible to ensure compliance with the emissions limits*."[38]

Carbon monoxide (CO) emissions in "synthetic minor" versus PSD permits

Aside from carbon dioxide (CO_2), carbon monoxide (CO) is the pollutant emitted in greatest quantities by biomass burning. High moisture and variable quality of biomass fuels lead to incomplete combustion, increasing CO emissions above levels typical for fossil fuel-fired facilities. Adding more oxygen to the combustion process can help reduce CO emissions, but doing so increases formation of "thermal" NOx, making it more difficult to remain within NOx emission limits.

[38] Alaa-Eldin A. Afifi, Georgia Environmental Protection Division, Air Protection Branch. Permit narrative for North Star Jefferson Renewable Energy Facility, page 32. May 2, 2012.

Table 4: Biomass power plants with synthetic minor status for carbon monoxide

Plant	State	MMBtu	MW	Boiler	CO control	Cap rate	CO (tons/yr)
Pinal Biomass Power, Maricopa	AZ	410	30	Stoker	none	0.13	240
DTE Stockton, Stockton	CA	699		Stoker	oxid cat	0.08	248
U.S. EcoGen Polk, Fort Meade	FL	740	57	FBB	none	0.08	246
ADAGE, Hamilton Cty	FL	834	56	FBB	none	0.07	245
Green Energy Partners, Lithonia	GA	186	10	Stoker	none	0.30	249
North Star Jefferson, Wadley	GA	321	22	FBB	none	0.18	249
Greenleaf Environmental Solutions, Cumming	GA	372	25	FBB	none	0.15	250
Greenway Renewable Power, LaGrange	GA	719	50		none	0.08	249
Plant Carl, Carnesville	GA	400	25	FBB	oxid cat	0.14	249
Wiregrass, Valdosta	GA	626	45	FBB	none	0.09	247
Lancaster Energy Partners, Thomaston	GA	215	15	Stoker	none	0.26	249
Lancaster Energy Partners, Macon	GA	220	16	Stoker	none	0.26	249
Fitzgerald Renewable Energy, Fitzgerald	GA	808	60		none	0.07	249
Piedmont Green Power, Barnesville	GA	657	55	Stoker	none	0.08	227
Hu Honua, Pepe'keo	HI	407	22	Stoker	none	0.14	246
Liberty Green, Scottsberg	IN	407	32	FBB	none	0.13	225
ecoPower, Hazard	KY	745		FBB	none	0.08	240
Menominee Biomass Energy, Menominee	MI	493		FBB	none	0.11	245
Sawyer Electric Co., Gwinn	MI	560		FBB	none	0.10	245
Perryville Renewable Energy, Perryville	MO	480	33	FBB	none	0.11	225
ReEnergy Black River, Fort Drum	NY	284	19	Stoker	none	0.20	250
Biogreen Sustainable Energy, La Pine	OR	353	25		none	0.16	247
Klamath Bioenergy, Klamath	OR	459		FBB	none	0.11	230
EDF Dorchester, Harleyville	SC	275	18	Stoker	none	0.20	241
EDF Allendale, Allendale	SC	275	18	Stoker	none	0.21	250
Loblolly Green Power, Newberry	SC	675	53	Stoker	oxid cat	0.08	222
Orangeburg County Biomass, Orangeburg	SC	525	35	FBB	none	0.11	250
NOVI Energy, South Boston	VA	629	50	Stoker	none	0.09	236

Table 4. Carbon monoxide limits for some synthetic minor source permits issued in recent years. The "cap rate" is the rate at which the unit would have to operate in order to stay below the specified tons of CO per year. "FBB" is fluidized bed boiler.

This problem is acknowledged in many bioenergy air permits, where it is common to see CO limits set considerably higher than what is achievable when the boiler is operated under ideal conditions. Despite this, however, a great number of bioenergy facilities, claim synthetic minor status for CO in order to avoid having to go through PSD permitting (Table 4).

How realistic is it that relatively large facilities can keep their CO emissions at less than 250 tons per year? The average allowable emission rate for the PSD facilities in our database (i.e., those that had gone through a BACT analysis) was around 0.2 lb/MMBtu. At that emission rate, a relatively small boiler of 285 MMBtu (around18 MW) would have the potential to emit 250 tons of CO per year, suggesting that most facilities, unless they are taking exceptional measures, are likely to be major sources for CO. Of the 88 permits in our database, 53 were capped at 250 tons or below for both CO and NOx – and the majority of these had boilers larger than 285 MMBtu.

In Table 4, the "cap rate" is the emission rate that the boiler would need to achieve in order to stay below its CO limit (assuming that the boiler is the only source of CO at the facility; in fact, the 250 ton cap is supposed to include all emissions at the facility, including emissions from fossil fuels burned at startup, emergency generators, etc). The cap rate is derived by rearranging equation 1, above:

Equation 2

$$\text{cap rate } \left(\frac{lb}{MMBtu}\right) = \text{tons per year } \div \left[\text{boiler capacity } \left(\frac{MMBtu}{hr}\right) * 8{,}760\ hrs\right] * 2{,}000\ \left(\frac{lb}{ton}\right)$$

Only two of the facilities in Table 4 proposed to use oxidation catalysts[39] to reduce CO emissions, with the rest planning to use "good combustion practices." According to the boiler maker Babcock and Wilcox, baseline CO emissions for stoker boilers (without an oxidation catalyst) are in the range of 0.1 - 0.3 lb/MMBtu when the boiler is being operated optimally at steady-state (i.e. not during startup and shutdown).[40] Fluidized bed boilers may have lower CO emissions rates of 0.015 - 0.15 lb/MMBtu at steady state[41] (the lowest permit limit found for an operating biomass boiler in EPA's permit clearinghouse[42] is that for the **50 MW Schiller Station bioenergy facility in Portsmouth, New Hampshire**, which has a limit of 0.1 lb/MMBtu for a circulating fluidized bed boiler).

It seems unlikely that all of the facilities in Table 4 would be capable of meeting the cap rate required to actually stay below 250 tons per year, given that in order to do so, many would have to *consistently* operate at rates even lower than 0.1 lb/MMBtu (including during periods of startup and

---

[39] An oxidation catalyst converts CO to CO_2 and thus reduces CO emissions. The chemical reaction is speeded by a metal catalyst, but this technology has been rarely proposed for use in biomass boilers, because installing and operating CO catalysts is expensive and because the catalyst can be fouled and deactivated by substances contained in the ash. .

[40] Bowman, J., et al. Biomass combustion technologies: A comparison of a biomass 50MW modern stoker fired system and a bubbling fluidized bed system. Presented at POWER-GEN International, December 8-10, 2009. Las Vegas, NV.

[41] Ibid.

[42] EPA's BACT Clearinghouse (http://cfpub.epa.gov/rblc/)contains permit limits for a number of facilities, but it is not comprehensive and does not contain information on recently issued permits.

shutdown, when emissions can increase – see Table 3). Facilities could shut down for part of the year to stay below 250 tons, but only a couple of the permits we reviewed contained limits on hours of operation.

EPA agrees: Synthetic minor emission caps in state-issued permits strain credulity

Our skepticism about whether facilities can meet their required cap rates is shared by the EPA. The agency rarely gets involved in state-issued air permits, but occasionally does weigh in. A letter from EPA Region IX to the Hawaii air permit issuing authority about the **23.8 MW (gross) Hu Honua coal to biomass conversion in Pepe'ekeo, Hawaii** (which has a CO emission factor of 0.17 lb/MMBtu set in the permit, but which would need to keep average emissions below 0.14 lb/MMBtu to stay below 250 tons) stated that the air permit application "*does not provide any documentation or justification of the CO emission factor,"* and that *"we have permitted two biomass facilities with stoker boilers that are approximately half the size of the proposed Hu Honua plant; yet the projected future actual CO emission and CO PTE of both facilities are much higher than Hu Honua's, and well above the 250 tpy PSD major source threshold. In sum, we have not seen any instance of a stoker boiler of the permittee's size being able to achieve the CO emission limits that the Clean Air Branch is proposing for this permit*."[43]

Hu Honua is a 22 MW plant, relatively small compared to a number of other facilities that are also claiming synthetic minor status for CO, making the implications of EPA's statements more far-reaching. When, even after the EPA letter, the Hawaii authorities issued the final permit for Hu Honua with few changes, a citizen group petitioned EPA to formally object to the permit on the grounds that it is illegal and unenforceable. In its response, EPA agreed that the Hu Honua permit limits for both CO and NOx were unenforceable, stating "*To effectively limit Hu Honua's CO and NOx PTE to less than 250 tpy, the CO and NOx emissions limits included in Section C6 of the Final Permit must apply at all times to all actual emissions, and all actual CO and NOx emissions must be considered in determining compliance with the respective limits*."[44] EPA's response makes it clear that not only must normal emissions be included, but startup and shutdown emissions and emissions during malfunctions or "upset" conditions must be counted, as well.

If a facility claims it is going to emit less than 250 tons of each pollutant to avoid PSD permitting, it needs to demonstrate this with testing and monitoring

However, while EPA was involved with the Hu Honua permit, the Agency inexplicably has not reacted to other permits with low implied CO emissions (such as the numerous facilities larger than Hu Honua listed in Table 4), most of which explicitly or implicitly exempt total facility emissions from counting toward the 250 ton total.

[43] Letter from Gerardo C. Rios, Chief, Permits office EPA Region IX, to Wilfred K. Nagamine, Manager, Clean Air Branch, Hawaii Department of Health. June 30, 2011.

[44] United States Environmental Protection Agency. In the matter of Hu Honua Bioenergy Facility, Pepeekeo, Hawaii. Permit No. 0724-01-C. Order responding to petitioner's request that the Administrator object to issuance of state operating permit. Petition No. IX-2011-1. Page 10.

The incongruity of permits that set a 250 ton cap for CO, almost no matter what the facility size, is illustrated graphically in Figure 4. The graph shows allowable CO emissions for new synthetic minor sources versus PSD-permitted sources from our permit database, in tons of CO emitted per year. Almost all the plants in Figure 4 – even the majority of the PSD-permitted plants that went through a BACT analysis – plan to use "good combustion practices" to control CO; only two of the synthetic minor sources and four of the PSD-permitted sources plan to use oxidation catalysts (highlighted). Thus, all other things being equal, as boiler capacity (in MMBtu per hour) increases, a facility's annual potential emissions (tons per year) should increase. This is the case for the permits issued under the PSD program, where achievable CO emissions rates are considered as part of a BACT analysis. However, the graph makes clear, this relationship does not apply for the group of synthetic minor sources, all of which claim they will emit 250 tons or less, no matter what their boiler capacity.

Figure 4: Projected emissions of carbon monoxide

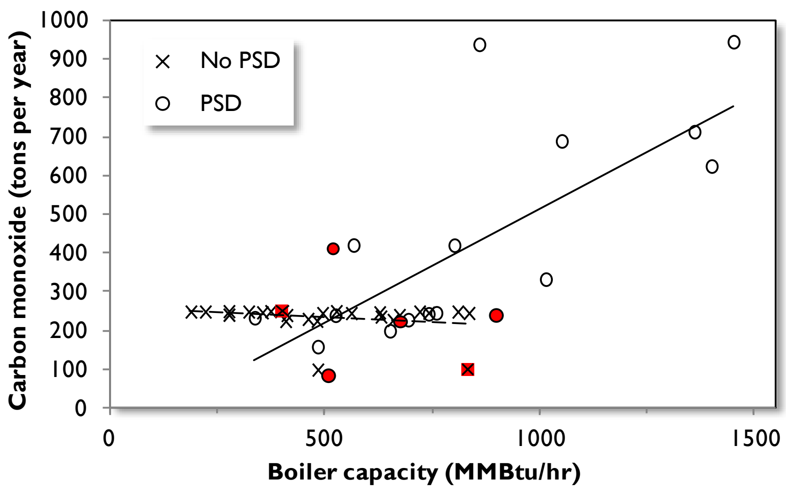


Figure 4. The relationship between permitted CO emissions for some facilities that went through PSD, versus synthetic minor sources that avoid PSD. Shaded markers represent facilities that propose to use oxidation catalysts to reduce CO emissions. Dashed line shows trend for non-PSD facilities; solid line shows trend for PSD facilities.

These data suggest that the 250 tons cap is problematic on both sides of the size spectrum. Small boilers that *could* limit their emissions below 250 tons, but nonetheless have the 250 ton cap as their only enforceable CO limit, are allowed to emit more pollution than they need to, while some large facilities that avoided PSD seem unlikely to be able to stay beneath the 250 ton cap, especially since total facility emissions (and not just boiler emissions) are supposed to be included.

Nitrogen oxide (NOx) emissions

To avoid PSD, a facility must accept a cap not only on CO, but also NOx. Table 5 the NOx limits for some of the synthetic minor source permits in our database.

Table 5: Biomass power plants with synthetic minor status for nitrogen oxides

Plant	State	MMBtu	MW	Boiler	NO_x control	Cap rate	NO_x (tons/yr)
Pinal Biomass Power, Maricopa	AZ	410	30	Stoker	SNCR	0.13	240
DTE Stockton, Stockton	CA	699	48	Stoker	SCR	0.04	108
U.S. EcoGen Polk, Fort Meade	FL	740	57	FBB	SCR	0.08	246
ADAGE, Hamilton Cty	FL	834	56	FBB	SCR	0.06	233
Green Energy Partners, Lithonia	GA	186	10	Stoker	not spec	0.03	25
North Star Jefferson, Wadley	GA	321	22	FBB	SCR	0.18	249
Greenleaf Environmental Solutions, Cumming	GA	372	25	FBB	SCR	0.02	25
Greenway Renewable Power, LaGrange	GA	719	50		SNCR	0.08	249
Plant Carl, Carnesville	GA	400	25	FBB	SNCR	0.14	249
Wiregrass, Valdosta	GA	626	45	FBB	SCR	0.09	247
Lancaster Energy Partners, Thomaston	GA	215	15	Stoker	SNCR	0.26	249
Lancaster Energy Partners, Macon	GA	220	16	Stoker	SNCR	0.26	249
Fitzgerald Renewable Energy, Fitzgerald	GA	808	60		SNCR	0.07	249
Piedmont Green Power, Barnesville	GA	657	55	Stoker	SNCR	0.08	228
Hu Honua, Pepe'keo	HI	407	22	Stoker	SNCR	0.12	210
Liberty Green, Scottsberg	IN	407	32	FBB	SNCR	0.14	245
ecoPower, Hazard	KY	745		FBB	SNCR	0.08	240
Menominee Biomass Energy, Menominee	MI	493		FBB	not spec	0.11	245
Sawyer Electric Co., Gwinn	MI	560		FBB	SNCR	0.10	245
Perryville Renewable Energy, Perryville	MO	480	33	FBB	SNCR	0.11	240
ReEnergy Black River, Fort Drum	NY	284	19	Stoker	SCR	0.20	250
Biogreen Sustainable Energy, La Pine	OR	353	25		SNCR	0.15	232
Klamath Bioenergy, Klamath	OR	459		FBB	SNCR	0.11	230
EDF Dorchester, Harleyville	SC	275	18	Stoker	SNCR	0.20	241
EDF Allendale, Allendale	SC	275	18	Stoker	SNCR	0.20	241
Loblolly Green Power, Newberry	SC	675	53	Stoker	MPCR*	0.07	222
Orangeburg County Biomass, Orangeburg	SC	525	35	FBB	SCR	0.11	250
NOVI Energy, South Boston	VA	629	50	Stoker	SCR	0.09	236

Table 5. Nitrogen dioxide limits for some synthetic minor source permits issued in recent years. "FBB" is fluidized bed boiler. "MPCR" is "multi-pollutant catalytic reactor."

While the majority of biomass permits we examined did not require external emissions controls for CO, nearly all required emissions controls for NOx – usually either Selective Catalytic Reduction (SCR) or Selective Non-Catalytic Reduction (SNCR). These controls force reducing agents (ammonia or urea) to react with the nitrogen oxides formed during combustion, converting the NOx in the flue gas to nitrogen gas (N_2). The stated efficiency of these controls varies tremendously. In our database, facilities planning to use SCR claim NOx conversion efficiencies ranging from 36 – 95%; claims for SNCR efficiency range from 45 – 73%. This wide range of claims is obviously problematic, as it seems unlikely that all claims can be met in reality.

As is the case for the 250 ton cap for CO, the NOx emission rates implied in Table 5 sometimes appear to be unrealistically low if the facility is stay under the emissions cap. For example, permit limits for the **Green Energy Resource Center in Lithonia, Georgia** seem unrealistic. The permit narrative states, "*Dekalb County is a non-attainment-area for ozone (NOx and VOC) and $PM_{2.5}$. The major source thresholds in the non-attainment area for NOx and VOC are 25 tons per year each. The potential VOC emissions are less than 25 tpy. Since the NOx potential to emit exceeds 25 tpy, the facility requests a permit limit to limit the NOx emissions to less than 25 tpy. Based on the projected emissions and control efficiencies, the facility will demonstrate through stack testing and continuous emission monitoring that the facility will be a synthetic minor source with respect to New Source Review.*"[45]

However, to meet this cap, the facility will have to keep average NOx emissions at about 0.03 lb/MMBtu, an extremely low level that is all the more extraordinary given that the company has proposed a novel emissions control system that has never been tried on a biomass energy plant before, a ceramic filter device that apparently incorporates NOx reduction capabilities. Similarly, the proposed **25 MW (net) Greenleaf Environmental Solutions plant in Cumming, Georgia**, which is also in the Atlanta non-attainment area, has an even lower NOx emissions rate it must meet – 0.015 lb/MMBtu – if it is to stay below its cap of 25 tons.

Some synthetic minor facilities are allowed to emit pollution disproportionate to their size

For synthetic minor permits at some facilities, however, the NOx emission rates required for a facility to avoid PSD may not be all that low. For instance, the permit for the **19 MW (net) ReEnergy Lyonsdale Biomass plant in Lyonsdale, New York** (which has a 290 MMBtu boiler) states that NOx emissions from the wood burning boiler are limited to 0.2 lb/MMBtu to avoid PSD.[46] This emission rate is about three times higher than NOx emission rates commonly required at coal plants and biomass plants that have gone through a BACT analysis as part of PSD permitting. This plant's permit allows it to be unnecessarily polluting, but since the facility is permitted to burn pallets and "non-recyclable fibrous material such as wax cardboard," the higher limit may be needed to accommodate surges in emissions that accompany burning waste materials.

---

[45] Renee Browne, Georgia Environmental Protection Division, Air Protection Branch. Permit narrative for Green Energy Resource Center, April 25, 2013.
[46] New York State Department of Environmental Conservation. Air Title V Facility Permit for Lyonsdale Biomass, Permit ID 6-2338-00012/00004. Effective date 08/16/2011.

Figure 5 shows that for facilities that go through PSD and a Best Available Control Technology analysis, annual NOx emissions tend to increase as boiler size increases, as expected. However, for the synthetic minor sources that avoid BACT, emission rates are capped around 250 tons or less.

Figure 5: Projected emissions of nitrogen oxides

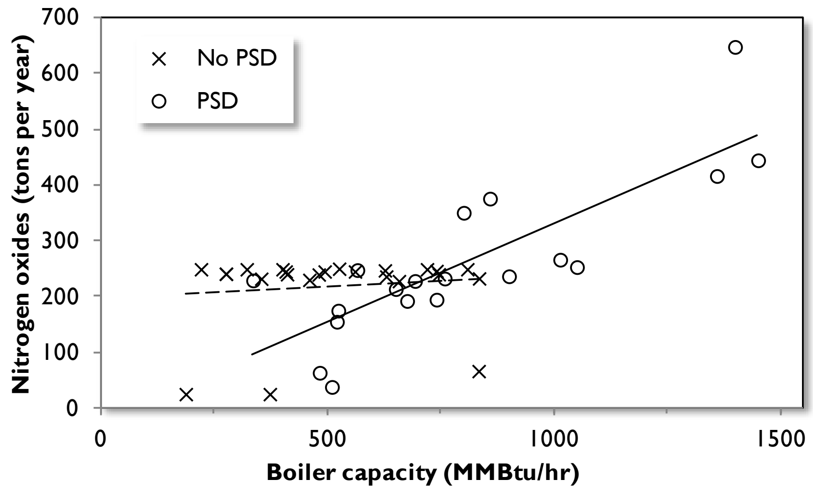


Figure 5. The relationship between permitted NO_x emissions for some facilities that went through PSD, versus synthetic minor sources that avoided PSD. Dashed line shows trend for no-PSD facilities; solid line shows trend for PSD facilities.

Although some larger synthetic minor facilities appear to be promising unrealistically low NOx emission rates, the graph makes it clear that allowable NOx emissions from smaller synthetic minor sources tend to be higher than they would be had the facility gone through a BACT analysis to determine the lowest emission levels that could be achieved.

Particulate matter (PM) emissions

All biomass power plants are large sources of particulate matter emissions; even facilities that have gone through a BACT analysis and have emission rates as low as 0.012 lb/MMBtu emit more particulate matter per MWh than a coal plant (Table 2, Figure 2). Because uncontrolled particulate matter emissions from combustion are large, all utility-scale biomass plants use some kind of particulate matter control, usually either a fabric filter ("baghouse") or an electrostatic precipitator (ESP), often in conjunction with a multiclone, which is a series of devices that use centrifugal force to spin out particles in the larger size classes.[47] Once these controls are in place, they are generally effective enough that almost no typically sized biomass plant is in danger of emitting more than 250 tons PM per year, meaning that PM is not usually a pollutant that triggers PSD for a new biomass power plant.[48] However, crucially, this assumption only holds if the plant is running normally

[47] Only one facility in our database, the Green Energy Partners plant in Lithonia, GA, is proposing to use something other than a fabric filter or ESP to control PM emissions, a ceramic filter from the TriMer corporation.

[48] However, for existing facilities undergoing a "major modification," PSD applicability is triggered when the increase in emissions caused by the modification exceeds certain triggering thresholds. The PSD major significance threshold for $PM_{2.5}$ is 10

during the whole year. Periods of startup, shutdown, and malfunctions can cause significant emissions of PM since certain controls, such as ESPs, are allowed to be non-operational during such time periods.

Even though all biomass plants use baghouses or ESPs, the NSPS emission limit of 0.03 lb/MMBtu that applies at most synthetic minor facilities is at least twice as high as rates of 0.012 lb/MMBtu to 0.015 lb/MMBtu that apply at facilities that have gone through a BACT analysis. When translated to tons of PM emitted per year, the allowable limits are likewise twice as high (Figure 6).

State-issued air permits have no limits on the most harmful forms of particulate matter

Figure 6: Projected emissions of filterable particulate matter

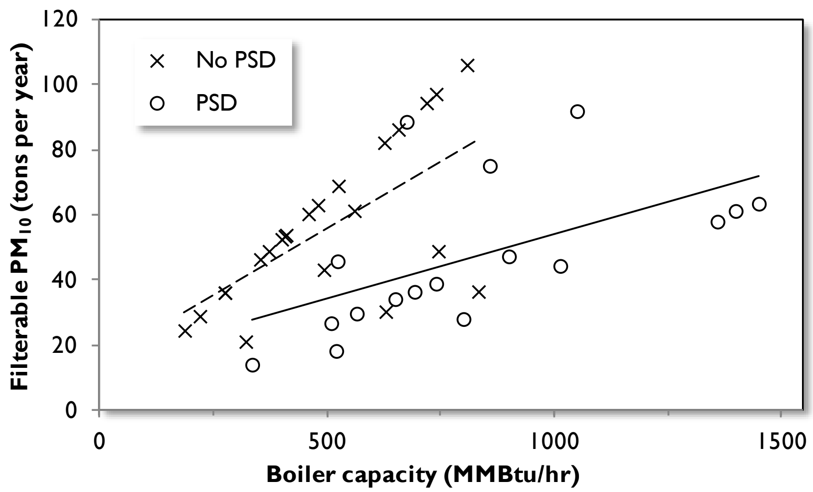


Figure 6. Allowable emissions of filterable PM_{10} for permits in our database. For nearly all the facilities that avoid PSD, the only required emission limit is the 0.03 lb/MMBtu PM_{10} limit set by the New Source Performance Standards. Dashed line shows trend for no-PSD facilities; solid line shows trend for PSD facilities. A couple of minor sources that did not go through PSD nonetheless had lower limits, pulling the dashed trendline down.

Particulate matter is a pollutant with immediate and dramatic health effects, and it is a pollutant where regulation under PSD can really reduce emissions. Particulate matter is regulated in two size classes, PM_{10}, and $PM_{2.5}$,[49] with the subscript referring to particle size or diameter in micrometers. Particulate matter is also regulated in two forms – filterable PM (the portion of PM that can be captured by a baghouse or ESP), and condensable PM (the portion of PM that condenses out of other pollutants into the atmosphere after being emitted from the smokestack). While condensable PM is considered to fall into the $PM_{2.5}$ size class, much of it is actually in the "ultrafine" size class, of 0.1 micron and below. These particles are considered the most dangerous to health, as they are so small, the penetrate deep into the respiratory system. The PSD program requires that emissions of

---

tpy of direct $PM_{2.5}$ emissions; 40 tpy of SO_2 emissions; or 40 tpy of NOx emissions unless demonstrated not to be a $PM_{2.5}$ precursor under paragraph (b)(50) of 40 CFR 52.21.

[49] $PM_{2.5}$ is a subset of PM_{10}.

$PM_{2.5}$, including condensable PM, be evaluated to assess a facility's impact on air quality.[50] In contrast, the only emission rate requirement included in most permits for synthetic minor facilities is the federal New Source Performance Standard (NSPS) for filterable particulate matter, which simply limits filterable PM_{10} emissions to less than 0.03 lb/MMBtu,[51] and specifically exempts facilities during periods of startup and shutdown.

Just because a facility is allowed to emit a certain amount of pollution doesn't mean it will. Fabric filter and electrostatic precipitator technologies should reduce filterable PM_{10} emissions to less than 0.03 lb/MMBtu (though emission rates can spike dramatically during startup and shutdown, when most synthetic minor facilities are specifically exempted from meeting an emissions limit – Table 3). However, because synthetic minor source permits contain no consideration or limits on condensable PM or $PM_{2.5}$, total emissions of PM are likely to greatly exceed emissions of just filterable PM. In fact, permitting agencies don't seem to have a consistent concept of the importance of condensable PM, even though it is an important part of total PM emissions. Regulation of condensable PM is chaotic. In our analysis of 23 permits where condensable PM rates were specified or could be estimated by subtracting filterable PM from total PM emissions, we determined that the ratio of allowable condensable emissions to filterable emissions varied significantly, with condensable PM rates ranging from 50% to 200% of filterable PM emission rates.

Particulate matter emissions from biomass power plants could be reduced considerably by requiring use of one of the many high efficiency filtration products that EPA certifies.[52] Table 6 shows how, for a representative 500 MMBtu/hr wood-burning boiler with an uncontrolled PM emission rate of 0.56 lb/MMBtu,[53] adding just tenths or one-hundredths of a decimal point in the efficiency of a filtration system can significantly decrease the amount of particulate matter emitted. The higher efficiency fabric filters produce a dramatic reduction in emissions even relative to the control efficiencies of 98% or 99% that are often promised in modern permits, and actually represent the "best available" technology for particulate matter control. Unfortunately, because EPA rules are so weak, with synthetic minor source permits only requiring that facilities meet the 0.03 lb/MMBtu NSPS limit for filterable PM, state-level permit writers have little regulatory basis for requiring facilities to use high-efficiency filters, even if they want to.

---

[50] Many permits use PM_{10} emissions as a proxy for $PM_{2.5}$, assuming that treating all PM as if it is in the smaller size class is the most conservative form of the analysis.

[51] U.S. EPA. 40 CFR Part 60. Standards of performance for electric utility steam generating units, industrial –commercial-institutional steam generating units, and small industrial-commercial-institutional steam generating units; final rule. Federal Register Vol. 71, No. 38, Feb. 27, 2006.

[52] EPA lists currently certified products at http://www.epa.gov/etv/vt-apc.html#bfp

[53] Value of 0.56 lb/MMBtu for uncontrolled PM emissions taken from Table 1 of background document to EPA's AP-42 compilation of emission factors (Eastern Research Group. Background document report on revisions to 5th Edition AP-42, Section 1.6, Wood Residue Combustion in Boilers. July, 2001).

Table 6: Synthetic minor sources are allowed to emit hundreds of times more particulate matter than the best-controlled facilities

Technology	Tons/year
Allowable emissions @ NSPS limit of 0.03 lb/MMBtu	65.70
Electrostatic precipitator @ 98%	24.53
Baghouse @ 99%	12.26
Baghouse @ 99.5%	6.13
Baghouse @ 99.9%	1.23
High-efficiency baghouse @ 99.99%	0.12

Table 6. Emissions of filterable PM_{10} from a 500 MMBtu wood-burning boiler employing control technologies with differing removal efficiencies. A biomass power plant operating at the NSPS limit of 0.03 lb/MMBtu would emit more than 500 times the PM of a plant employing a high-efficiency baghouse.

In some cases, when regulators do have the option of requiring stricter emissions controls, they don't. For instance, the **new 25 MW biomass boiler at Verso Paper in Bucksport, Maine**, which did go through a BACT analysis, was nonetheless permitted with a 0.03 lb/MMBtu emissions rate for PM,[54] the same rate it would be required to meet if no BACT analysis had been conducted. This large, high-emissions plant is located immediately adjacent to homes and schools.

Sulfur dioxide (SO_2) emissions

Wood is a relatively low-sulfur fuel, and thus generally emits less sulfur dioxide than coal, although relative to natural gas, its emissions of SO_2 are far higher (Figure 2). While sulfur content of "unadulterated" wood samples in EPA's fuel database[55] averages less than 1%, sulfur content can be much higher if wood chips are sourced from construction and demolition debris, which can be contaminated with gypsum wallboard, a material that contains sulfur. If all sulfur in biomass were converted to SO_2 during combustion, the sulfur in even unadulterated fuels would be sufficient to create more than 250 tons of annual emissions at most large biomass power plants. However, SO_2 is neutralized naturally during combustion by alkaline ash products so that up to 90% of it is incorporated in ash, rather than exiting the stack in the flue gas.[56] Facilities that inject alkaline agents like limestone to neutralize hydrochloric acid emissions can also reduce SO_2 emissions.

---

[54] Maine Department of Environmental Protection. Departmental Findings of fact and order, New Source Review, Amendment #3 for Verso Bucksport, LLC. A-22-77-4-A.

[55] Draft Emissions Database for Boilers and Process Heaters Containing Stack Test, CEM, & Fuel Analysis Data Reported under ICR No. 2286.01 & ICR No. 2286.03 (version 8) May, 2012. Available at http://www.epa.gov/airtoxics/boiler/boilerpg.html (database labeled "Boiler MACT Draft Emissions and Survey Results Databases")

[56] Oglesby, H.S. and Blosser, R.O. 1980. Information on the sulfur content of bark and its contribution to SO2 emissions when burned as a fuel. Journal of the Air Pollution Control Association, 30:7, 769-772.

Synthetic minor facilities tend to have higher allowable SO_2 emission rates than facilities that have gone through PSD permitting. However, in Figure 7, the non-PSD facilities with allowable SO_2 emissions around 250 tons did include sorbent injection in their emissions controls, suggesting that actual emissions would be lower than allowable emissions. Overall, 13 facilities did not appear to plan on using sorbent injection, including a couple of PSD-permitted facilities that plant to rely on "natural" ash sorption of to control SO_2 and HCl emissions.

Figure 7: Projected emissions of sulfur dioxide

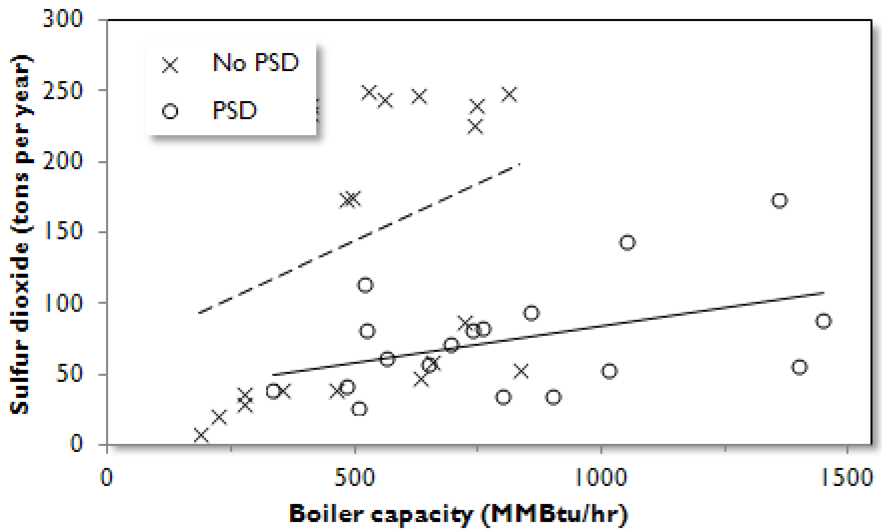


Figure 7. The relationship between permitted SO_2 emissions for some facilities that went through PSD, versus synthetic minor sources that avoid PSD. Dashed line shows trend for no-PSD facilities; solid line shows trend for PSD facilities.

Toxic air pollution from biomass energy

Hazardous air pollutants (HAPs) is the collective name for the group of 187+ compounds that EPA considers especially toxic in air. Although biomass energy is routinely presented as "clean," in fact, biomass burning emits large amounts of HAPs, also known as "air toxics" – including hydrochloric acid, dioxins, "organic" compounds such as benzene and formaldehyde, and heavy metals like arsenic, chromium, cadmium, lead, and mercury. Emissions of metals and other HAPs are likely to be highest when contaminated materials like construction and demolition debris are burned as fuel, but burning just unadulterated forest wood also emits toxic air pollutants. Some of these compounds are contained in the fuel itself while others are created during the combustion process. As we discuss below, the use of contaminated fuels is increasing in the bioenergy industry, thus HAPs emissions from the biomass power industry are likely to increase.

Burning biomass emits a wide variety of air toxics, but the HAP typically thought to be emitted in the greatest quantities is hydrochloric acid (HCl). Other HAPs emitted at relatively high rates include acrolein, acetaldehyde, styrene, benzene, and formaldehyde, which have various respiratory and carcinogenic effects. A co-firing test conducted at the **600 MW Killen coal plant in Wrightsville, Ohio**, where a small amount of biomass was burned at a coal plant, showed the dramatic potential for biomass to increase emissions of air toxics. There, adding just 5% biomass to the coal increased CO emissions by 50%, while increasing the yearly potential to emit for benzene from 1.51 tons to 6.89 tons per year and the PTE for formaldehyde from 0.28 tons to 5.98 tons per year (both these organic HAPs are classified as carcinogens).[57] It is important to note, however, that many HAPs (such as dioxins), while emitted in small quantities as compared to the HAPs discussed above, can pose very significant health risks, due to their high levels of toxicity.

How the Clean Air Act regulates emissions of hazardous air pollutants (HAPs)

Bioenergy plants emit acrolein, styrene, benzene, and formaldehyde, as well as heavy metals like arsenic, chromium, cadmium, lead, and mercury.

The Clean Air Act regulates HAPs by setting National Emissions Standards for Hazardous Air Pollutants (NESHAPS) for different types of emissions sources. The Act requires EPA to set emission standards for each HAP that a source category emits, although the regulations as written do not appear to meet this standard. The allowable emission levels for HAPs, known as the Maximum Achievable Control Technology (MACT) standards, are supposed to be derived by collecting emissions data from existing sources, then setting standards for new facilities based on the best performing (lowest emitting) units of each type.[58]

As EPA currently implements the rules, different types of facilities are held to different MACT standards, with one category being units described as "designed to burn" biomass. Under EPA's current rules, if a boiler burns or co-fires more than 10% biomass, and is greater than 10 MMBtu/hr, it is regulated as a biomass burner under the Industrial/Commercial/Institutional (ICI) rule, known informally as the "boiler rule"[59] or boiler MACT. Amazingly, this rule regulates a facility burning 90% coal and 10% biomass as a biomass burner, which as shown below, has consequences for emissions, as biomass boilers are allowed to emit more pollution than coal boilers.

The "boiler rule" regulates all biomass boilers, no matter how large they are, and sets separate standards for emissions from fossil-fueled boilers up to 25 MW in capacity. However, oil, coal and gas facilities larger than 25 MW are governed not by the boiler rule, but by a separate Electric Generating Unit (EGU) rule, which is more rigorous (discussed below). If a facility burns a

[57] Technical support document, DP&L Killen Electric Generating Station, Boiler #2 coal and renewable fuel co-firing. 2010;
[58] Section 112(d)(2) of the Clean Air Act requires the maximum degree of reduction in emissions that can be achieved, considering cost and other factors, through the full range of potential reduction measures. 42 U.S.C. § 7412(d)(2). In addition, § 112(d)(3) provides that regardless of cost, standards for new and existing facilities must reflect the emission level achieved by the best performing similar sources. 42 U.S.C. § 7412(d)(3).
[59] Whereas coal plants larger than 25 MW are held to a stricter standard for emissions under the Electric Generating Unit MACT standard, all biomass plants, regardless of how large they are, are govern by the more lenient "boiler" MACT

material classified as a commercial or industrial waste[60] it is regulated under the Commercial and Industrial Solid Waste Incinerator rule (CISWI).

Under the boiler rule, a facility is considered a "major" source for HAPs if it has the potential to emit more than 10 tons of any one HAP or more than 25 tons of all HAPs in a year. If potential emissions are anticipated during the permitting process to be less than this, a facility is classified as a minor source, known as an "area" source in MACT parlance. In some cases, the MACT standards set emission limits directly for the HAP in question; in the boiler rule, however, only HCl and mercury are regulated directly, and other HAPs are regulated indirectly by setting limits on emissions of PM and CO, which EPA has claimed can serve as "surrogates" for emissions of various co-emitted HAPs.[61]

While the term "maximum" achievable control technology (MACT) for hazardous air pollutants would imply that HAP emissions are controlled to the greatest degree possible, EPA's approach, and the way data are manipulated to set standards, have not resulted in protective standards. As an area source, the only limit a biomass burner greater than 30 MMBtu[62] must meet under the rule is a filterable PM emissions rate of 0.03 lb/MMBtu, the same rate as required under the NSPS, as described above in the section on PSD avoidance. The biomass area source rule does not set any emissions limits on dioxins, other organic HAPs like benzene and formaldehyde, metals like mercury, arsenic, and lead, or hydrochloric acid (HCl) and other acid gases.

Under the boiler rule, the majority of biomass power plants have almost no restrictions on the amount of toxic pollution they can emit.

Since the area source standard is so weak, it might be expected that emissions standards for major sources of HAPs (those that anticipating exceeding the 10/25 ton limit) would be more rigorous, but in fact, the filterable PM standard for stoker boilers under the major source rule is also 0.03 lb/MMBtu, the <u>same as for area sources</u>, although the filterable PM standard for bubbling fluidized bed boilers is one third the standard for stokers, at 0.0098 lb/MMBtu. In general, the MACT standards are far more lax than what can be routinely achieved using present-day technology. For example, the 0.03 lb/MMBtu filterable PM limit for major source stoker boilers (and area sources) is orders of magnitude higher than filterable PM emissions levels that can be achieved using high-efficiency fabric filters discussed above, as shown in Table 6. The CO standard set by the major source MACT rule is higher than rates commonly set by BACT determinations, as we discuss in more detail below. The major source MACT limit for HCl, which is supposed to serve as a proxy for emissions of other acid gases like hydrogen fluoride, is set at 0.022 lb/MMBtu, about an order of magnitude higher than emissions that can be achieved using sorbent injection. The limit is so high, it allows facilities that have declared themselves major sources for HAPs, like the **31 MW unit being added at the Sierra Pacific Anderson plant in Anderson, California,** to be built *without* HCl controls. That facility projects emitting 45 tons

[60] Municipal waste, medical waste, sewage sludge, and certain other types of waste are regulated separately.
[61] There is considerable debate as to whether these proxies are at all valid, and much evidence that emissions of certain HAPs are decoupled from their proxies.
[62] The rule sets the filterable PM rate at 0.07lb/MMBtu for biomass burners that are 10 – 30 MMBtu in capacity.

of HCl per year. Likewise, the **45 MW (gross) Aspen facility, in Lufkin, Texas**, was permitted as a major source for HAPs with a permit limit of 57 tons of HCl per year, and will not use a sorbent system to control HCl.[63]

Of the permits that we reviewed, the majority were designated as area sources for HAPs, no matter what their boiler size; just 19 (22%) were clearly identified as major sources for HAPs (some simply did not discuss HAPs in their construction permit at all.[64]) As neither the major source rule nor the area source rule is particularly restrictive, the question is what facilities hope to accomplish by being designated as area sources for HAPs. The lack of any emission limits in the area source rule other than the 0.03 lb/MMBtu limit for filterable PM is no doubt attractive for facilities wishing to minimize the requirements they must meet, but as we discuss below, facilities may be challenged to demonstrate that they are truly area sources.

EPA rules let biomass plants emit more toxic air pollutants than coal plants

How do the boiler rule emissions standards for bioenergy compare to standards set for coal plants? We focus here on filterable PM standards, since particulate matter is an important threat to health on its own and is treated by EPA as a proxy for heavy metal emissions under the boiler rule, which does not regulate heavy metal emissions directly. Under the rule, for filterable PM:

- Area source biomass boilers greater than 30 MMBtu/hr are allowed to emit 0.03 lb/MMBtu, the same as an area source coal boiler.
- Major source biomass stoker boilers[65] are allowed to emit more than 27 times the PM of a major source coal boiler (0.03 lb/MMBtu for bioenergy, versus 0.0011 lb/MMBtu for coal).
- Major source fluidized bed biomass boilers are allowed to emit almost 9 times the PM of a major source coal boiler (0.0098 lb/MMBtu for bioenergy, versus 0.0011 lb/MMBtu for coal).

Even under "maximum achievable" standards for air toxics, biomass plants are allowed to be more polluting than coal plants.

Although all biomass energy facilities of any size are regulated under the boiler rule, coal plants larger than 25 MW are regulated under the separate and relatively more rigorous Electric Generating Unit (EGU) MACT rule, which sets the filterable PM emission rate on an output basis,[66] at 0.09 lb/MWh. To do a biomass to coal comparison for two representative 50 MW power plants, where the coal plant is regulated under the EGU rule and the biomass plant

[63] Technical briefing sheet for Aspen Power LLC, Permit No.: 81706 and PDS-TX-1089, and HAP12

[64] In some cases this may be because HAPs are handled by Title V operating permits, which are issued subsequent to construction permits. Most of the permits we reviewed were construction permits, but our database also included a few Title V permits.

[65] For major sources (facilities that exceed the 10/25 ton emissions threshold), the boiler rule sets separate standards for biomass and coal stoker boilers and fluidized bed boilers.

[66] Pollution emissions expressed on an output basis is in units of pounds of pollutant emitted per megawatt-hour of electricity generated; emission expressed on an input basis is in units of pounds of pollutant emitted per million Btu (MMBtu) of boiler capacity, an expression of the heat input to the boiler.

is regulated under the boiler rule, therefore requires converting the bioenergy MACT standard (which is expressed on an input basis, as lb/MMBtu) to an output basis.[67]

Assuming a 24% conversion of energy to electricity for bioenergy, which is a typical value for large-scale bioenergy facilities, for filterable particulate matter:

- The biomass boiler MACT standard of 0.03 lb/MMBtu for a stoker boiler translates to a rate of 0.427 lb/MWh on an output basis, <u>474% the standard for a coal plant regulated under the EGU rule</u>,
- The biomass boiler MACT standard of 0.0098 lb/MMBtu for a fluidized bed boiler translates to a rate of 0.139 lb/MWh on an output basis,[68] <u>154% the standard for a coal plant</u>.

Thus, even subject to the "maximum achievable" control technology standard for hazardous air pollutants, biomass power plants are allowed to emit dramatically more particulate pollution than coal plants.

EPA rules let biomass plants emit more air toxics than waste incinerators

Under the Clean Air Act, how much pollution an industrial boiler is allowed to emit depends in part on whether it is classified as a biomass burner (an ICI unit) or a waste incinerator (a CISWI unit, which burns commercial and industrial waste).[69] Waste incinerators are generally better regulated than biomass burners, as the CISWI standards apply to *all* units regardless of their size, based on potential to emit, and because the rule regulates a larger number of the pollutants likely to be present in waste, and generally regulates them more tightly (Table 7). This seems reasonable, given that burning wastes is likely to emit more toxins than burning wood and other fuels typically thought of as "biomass," but as we explain below, EPA's new rules blur the line between biomass and waste, allowing a greater amount of contaminated fuels to be burned as biomass in area source boilers, which have no emission limits for HAPs.

As shown in Table 7, while the CISWI rule is not especially rigorous, it does recognize the potential for heavy metals and dioxin emissions from burning waste materials, regulating a couple of metals directly (an important exception is that the CISWI rule does not set an emission limit for arsenic, which is one of the main ingredients in the copper-chromium-arsenate (CCA) cocktail that is used to pressure-treat wood). Unlike the incinerator rule, the boiler rule only regulates non-mercury metals indirectly, by setting emission standards for filterable particulate matter, which EPA considers a proxy for metals emissions.

---

[67] To do this, one divides boiler capacity by the efficiency of the conversion from heat input to electricity, and converts units of MMBtu to MWh. The conversion from btu to MWh is made assuming 3,413,000 btu per MWh

[68] These conversions assume 24% efficiency for the biomass boilers.

[69] Municipal waste, medical waste, sewage sludge, and certain other types of waste are regulated separately.

Table 7: EPA barely regulates toxic air pollution from biomass plants

CISWI limit for ERU's burning biomass		ICI Major Source limits Stoker boilers		ICI Major Source limits Fluidized bed boilers		ICI Area Source limits	
PM, filterable (mg/dscm)	**5.1**	PM, filterable (lb/MMBtu)	**0.03**	PM, filterable (lb/MMBtu)	**0.0098**	PM, filterable (lb/MMBtu)	**0.03**
Carbon monoxide (ppm at 7% O_2)	**240**	Carbon monoxide (ppm at 3% O_2)	**620**	Carbon monoxide (ppm)	**230**		
Hydrogen chloride (ppmv)	**0.2**	Hydrogen chloride (lb/MMBtu)	**0.022**	Hydrogen chloride (lb/MMBtu)	**0.022**		
Mercury (mg/dscm)	**0.0022**	Mercury (lb/MMBtu)	**0.0000008**	Mercury (lb/MMBtu)	**0.0000008**		
Lead (mg/dscm)	**0.014**						
Cadmium (mg/dscm)	**0.0014**						
Dioxin, furans, total (ng/dscm)	**0.52**						
Dioxin, furans, Toxic Equivalents (TEQ) (ng/dscm)	**0.076**						
Nitrogen oxides (ppmv)	**290**						
Sulfur Dioxide (ppmv)	**7.3**						

Table 7. Allowable emissions under EPA's incinerator rule and major and area source boiler rules.

A biomass plant is allowed to emit ten times more fine particulate matter than a waste incinerator

Because the incinerator and boiler rules express emission rates for the same pollutants using different units, direct comparisons are difficult. However, the comparisons are possible by making reasonable assumptions regarding boiler capacity and stack flow for a facility regulated as either a biomass burner or an incinerator. Considering a representative 50 MW facility with a 740 MMBtu/hr stoker boiler:[70]

- If classified as an incinerator, it would be allowed to emit 9.5 tons per year of filterable PM. If classified as a biomass burner, it would be allowed to emit more than 10 times as much, 97 tons per year, under both the area source rule and the major source rule for stoker boilers. If filterable PM truly is a proxy for emissions of metals, then this means that ten times more heavy metals would be released at a facility regulated as a biomass burner.

[70] These parameters were taken from the permit for the Russell Biomass plant, a 50 MW wood burner that was proposed in Massachusetts.

- As an incinerator, the facility would be allowed to emit 1,518 tons/yr of CO, but double that amount – 3,045 tons/yr – under the major source boiler rule.[71] Importantly, *both* these limits are so high, they are nearly meaningless, as large biomass plants permitted as synthetic minor sources under PSD routinely claim to keep CO emissions at one-tenth this level– see Table 4 and Figure 4, earlier. In fact, the allowable levels of CO emission under the biomass MACT are so high, it is doubtful whether EPA's treatment of CO as a proxy for hazardous air pollutants like dioxin, benzene and formaldehyde is at all meaningful.
- Allowable HCl emissions under the incinerator rule would be 1.28 tons/yr, whereas the rule for major source biomass facilities would allow 5,546% this amount, 71 tons/yr.
- Allowable emissions of mercury would be higher under the incinerator rule than the major source boiler rule, at 8.2 lb/yr versus 5.2 lb/yr, but unlike emissions of CO and PM, which are products of combustion from all fuels, actual mercury emissions depend on the amount of mercury in the fuel.

Bioenergy emissions of Hazardous Air Pollutants: Clean Air Act loopholes

As is the case for criteria pollutants, the bioenergy industry seeks to avoid EPA regulation of hazardous air pollutants. The industry employs a variety of ploys to downplay toxic emissions.

Loophole 4: Most biomass plants have no restrictions on hazardous emissions

As for PSD permitting, the Clean Air Act allows facilities (other than incinerators) to claim "synthetic" minor source status for emissions of HAPs, stating that the facility will stay under the 10/25 ton per year triggering threshold. Claiming area source status is common – of the bioenergy permits that we reviewed, 52 (59%) were synthetic minor sources for HAPs and just 19 (22%) clearly were identified as major sources for HAPs; the rest simply did not discuss HAPs in their permit at all.[72] Facilities claiming area source status by capping HAPs emissions in their permit below the 10/25 ton threshold ranged in size from the **11.5 MW (gross) Green Energy Resources facility proposed in Lithonia, Georgia**, which is limited by its permit to emitting less than 24.5 tons of all HAPs annually,[73] to the **116 MW (gross) Gainesville Renewable Energy (GREC) facility in Florida**, which was in its initial permit limited to emitting 24.7 tons of all HAPs annually.[74] Interestingly, although the GREC application documents initially stated "*GREC will be a major source of HAPs since the potential facility emissions exceed 10 tpy for any individual*

[71] Converting the CISWI limit for CO to 3% oxygen basis to make it comparable with the limit expressed in the boiler rule, the value is 309 ppm.

[72] Failure to discuss HAPs in a preconstruction permit may indicate that the facility will set HAPs limits in the Title V operating permit; however, if a facility is declaring as a major source for HAPs, it is likely that emissions rates and controls will be referenced in the preconstruction permit.

[73] Georgia Department of Natural Resources, Environmental Protection Division. Permit N. 4911-089-0379-E-01-0, for Green Energy Resource Center. April 26, 2013.

[74] Florida Department of Environmental Protection. Air Permit No. 001031-001-AC for Gainesville Renewable Energy. December 29, 2010.

HAP and 25 tpy for total combined HAPs,"[75] a subsequent evaluation reversed this, stating "*The applicant believes that the proposed GREC project alone (the BFB in particular) will not have a PTE of any single HAP that is equal to or greater than 10 TPY or of all aggregated HAP equal to or greater than 25 TPY*."[76]

Such claims and sudden conversions to area source status for HAPS are not uncommon in the bioenergy world; as we discuss in more detail below, the **58 MW (gross) ecoPower plant being built in Hazard, Kentucky,** also abruptly and inexplicably reduced its projected emissions estimate of HAPs in order to be regulated as a synthetic area source, and a permitting document for the proposed **54.5 MW (net) Piedmont Green Power in Barnesville, Georgia** limits emissions of HAPs to 24.9 tons, stating "*The potential rates exceed this rate. However actual emissions are limited to this rate*."[77] In fact, under federal rules, this constitutes an admission that the facility is a major source, but it was not regulated as such.

How is it that the majority of facilities we reviewed claim to be area sources for HAPs, no matter what their boiler size? There are two main ways that facilities justify this claim. First, because HCl is the HAP that tends to be emitted in the largest quantities by biomass burning, and may easily exceed the annual 10 ton limit, facilities sometimes propose to install an acid-neutralizing sorbent injection system to control emissions. Following a one-time initial emissions test (which may take place sometime in the first 6 months of operation), if a facility is found to be emitting too much HCl to stay below the 10-ton limit per year, it can increase the amount of sorbent until the rate drops to a level where staying below the cap seems feasible. Setting aside the lack of requirements to then maintain this sorbent injection rate at all times, only 51 of the 88 permits we reviewed (58%) clearly required use of sorbents to reduce HCl emissions – in the other cases, facilities claimed area source status for HAPs without promising to control HCl emissions at all.

Loophole 5: The biomass industry lowballs estimates of toxic emissions to avoid regulation

Another way to "reduce" emissions of HAPs, at least on paper, is to simply claim that a biomass plant won't emit much toxic pollution.[78] EPA's published "AP-42" emission factors for HAPs emitted by wood-burning are supposed to be used to calculate total emissions of HAPs during the permitting process. However, the bioenergy industry doesn't like to use EPA's factors, claiming they are too high, and seeks to use lower emissions factors whenever possible. Very often, bioenergy developers use a set of emissions factors from the National Council on Air and Stream Improvement (NCASI), an opaque forestry and bioenergy industry advocacy group (Table 8).

---

[75] Environmental Consulting and Technology, Inc. Gainesville Renewable Energy Center Prevention of Significant Deterioration/Air Construction Permit Application. November, 2009. Section 6, p. 6-1.
[76] Florida Department of Environmental Protection. Technical Evaluation and Preliminary Determination, Gainesville Renewable Energy Center, LLC. July 14, 2010. Page 9.
[77] Alaa-Eldin A. Afifi, Georgia Environmental Protection Division, Air Protection Branch. Permit narrative for Piedmont Green Power. February 2, 2010.
[78] Just as for criteria pollutants, the total amount of HAPs emitted by a plant is estimated as the product of boiler capacity (MMBtu/hr) and the emission factor for each pollutant (in lb/MMBtu), producing an hourly rate (pounds per hour; see Equation 1). This rate is then multiplied by 8,760, the number of hours in a year, to estimate annual emissions. The lower the emission rate assumed, the lower the emissions.

Table 8: Industry data helps biomass plants lowball projected emissions of air toxics

Hazardous Air Pollutant	AP-42 factor (lb/MMBtu)	NCASI factor (lb/MMBtu)	NCASI as % of AP-42	Total lb AP-42	Total lb NCASI
ACETALDEHYDE	8.300E-04	1.90E-04	22.9%	1,352.4	309.6
ACETONE	1.900E-04	2.20E-04	115.8%	309.6	358.5
ACROLEIN	4.000E-03	7.80E-05 *	2.0%	6,517.4	127.1
ANTIMONY	7.900E-06	4.20E-07	5.3%	12.9	0.7
ARSENIC	2.200E-05	1.00E-06	4.5%	35.8	1.6
BARIUM	1.700E-04	1.60E-04	94.1%	277.0	260.7
BENZALDEHYDE	8.500E-07	3.00E-06	352.9%	1.4	4.9
BENZENE	4.200E-03	3.30E-03	78.6%	6,843.3	5,376.9
BERYLLIUM	1.100E-06	1.90E-06	172.7%	1.8	3.1
BIS(2-ETHYLHEXYL)PHTHALATE	4.700E-08	4.70E-08	100.0%	0.1	0.1
CADMIUM	4.100E-06	1.90E-06	46.3%	6.7	3.1
CARBON TETRACHLORIDE	4.500E-05	8.90E-07 *	2.0%	73.3	1.5
CHLOROBENZENE	3.300E-05	1.70E-05	51.5%	53.8	27.7
CHLOROFORM	2.800E-05	3.10E-05	110.7%	45.6	50.5
CHROMIUM	2.100E-05	6.24E-07	3.0%	34.2	1.0
COBALT	6.500E-06	1.90E-07	2.9%	10.6	0.3
COPPER	4.900E-05	5.50E-06	11.2%	79.8	9.0
DICHLOROMETHANE	2.900E-04	5.40E-04	186.2%	472.5	879.9
ETHYL BENZENE	3.100E-05	6.80E-06 *	21.9%	50.5	11.1
FORMALDEHYDE	4.400E-03	1.30E-03	29.5%	7,169.2	2,118.2
HYDROCHLORIC ACID	1.900E-02	6.70E-04	3.5%	30,957.8	1,091.7
LEAD	4.800E-05	5.80E-06	12.1%	78.2	9.5
MANGANESE	1.600E-03	1.50E-04	9.4%	2,607.0	244.4
MERCURY	3.500E-06	9.90E-07	28.3%	5.7	1.6
METHYL ETHYL KETONE	5.400E-06	9.10E-06	168.5%	8.8	14.8
NAPHTHALENE	9.700E-05	1.60E-04	164.9%	158.0	260.7
NICKEL	3.300E-05	2.90E-06	8.8%	53.8	4.7
PENTACHLOROPHENOL	5.100E-08	4.60E-08	90.2%	0.1	0.1
PHENOL	5.100E-05	1.40E-05	27.5%	83.1	22.8
SELENIUM	2.800E-06	3.00E-06	107.1%	4.6	4.9
STYRENE	1.900E-03	6.40E-04	33.7%	3,095.8	1,042.8
TOLUENE	9.200E-04	2.90E-05	3.2%	1,499.0	47.3
VINYL CHLORIDE	1.800E-05	1.80E-05	100.0%	29.3	29.3
				Total tons AP-42	**Total tons NCASI**
				31.0	**6.2**

Table 8. HAPs emissions based on potential to emit for a 186 MMBtu boiler. Shaded rows represent air toxics where the emissions factor from NCASI is lower than the EPA factor (data from EPA's AP-42, and NCASI Bulletin 858; NCASI emissions factors marked with asterisks are median values, for instances when mean is not presented).

Whereas EPA's AP-42 emissions factors are based on data that can be publically reviewed, NCASI's emission factors, and the data upon which they are based, are only available to industry partners who pay thousands of dollars per year for membership in NCASI. However, we gained access to NCASI's emissions factors because the publication that contains the information, NCASI Technical Bulletin #858, has been reproduced in air permit applications that we have reviewed. This publication contains the emission factors but none of the underlying data upon which they are based.

Companies use industry-provided emissions factors to avoid regulation as major sources for air toxics

As shown in Table 8, NCASI's industry-supplied emission factors tend to be much lower than EPA's AP-42 factors (shaded rows represent air toxics where the emissions factor from NCASI is lower than the EPA factor). There are only ten instances out of the 33 HAPs shown in the table where NCASI factors are the same or greater than the EPA factors, and for the HAPs with the highest AP-42 factors (acrolein, benzene, formaldehyde, hydrochloric acid, manganese, and styrene, dark shading) the NCASI factors are consistently and significantly lower – for instance, NCASI's emissions factor for acrolein is just 2% of the EPA emission factor.

The fact that NCASI emissions factors are so much lower than EPA's makes a real difference when calculating total HAPs emissions from a bioenergy facility. For example, applying the EPA and NCASI emission factors to the 186 MMBtu boiler at the proposed **11.5 MW Green Energy Resource Center in Lithonia, Georgia** produces dramatically different estimates of total tons of annual HAPs emissions. Estimating HAPs emissions using the EPA-sanctioned factors, the plant would emit 31tons of HAPs a year, making it a major source and subject to regulation under the major source boiler rule, whereas under the NCASI factors, the total is 6.2 tons. Because the air permitting branch of the Georgia Environmental Protection Division uncritically accepts and uses NCASI emissions factors with no independent evaluation, the plant in Lithonia was permitted as an area source and is subject to no emission limits for air toxics. This was the case for every biomass power plant permit in Georgia that we have reviewed, with the exception of two facilities.[79]

While EPA has mostly avoided getting drawn into questions about whether facilities should be using non-EPA sanctioned emissions factors for HAPs, the agency has occasionally commented. In their letter to the Hawaii air permitting authority on the **23.8 MW (gross) Hu Honua coal to biomass conversion in Pepe'ekeo, Hawaii**,[80] EPA Region 9 stated that it was *not* acceptable to use non-AP-42 emission factors without justifying why these factors were better than the EPA factors. However, the use of these non-EPA sanctioned factors is widely accepted by state

---

[79] The Georgia biomass plants we reviewed that have been given area source status for HAPs are: 40 MW Graphic Packaging, Macon; 10 MW Green Energy Partners. Lithonia; 22 MW North Star Jefferson, Wadley ; 25 MW Greenleaf Environmental Solutions, Cumming; 49.8 MW Greenway Renewable Power, LaGrange; 45 MW Wiregrass, Valdosta; 100 MW Warren County Biomass, Warrenton; 15 MW Lancaster Energy Partners, Thomaston; 16 MW Lancaster Energy Partners, Macon; 60 MW Fitzgerald Renewable Energy, Fitzgerald; 54.5 MW Piedmont Green Power, Barnesville. The two plants permitted as major sources were: 110 MW Yellow Pine Energy, Fort Gaines; 25 MW Plant Carl, Carnesville (poultry-waste burner).

[80] Letter from Gerardo C. Rios, Chief, Permits office EPA Region IX, to Wilfred K. Nagamine, Manager, Clean Air Branch, Hawaii Department of Health. June 30, 2011.

permitting authorities, especially in states like Georgia that tend to look favorably on forestry-related industries. Since EPA as a whole does not review many of the permits where these NCASI factors are being used, the Agency appears to be turning a blind eye to the variety of methods being used to lowball HAPs emissions. One of the most egregious examples is the proposed **50 MW (net) ecoPower facility in Hazard, Kentucky**, which invented their own emissions factors using selected emissions data, thus estimating less than ten tons of HAPs *overall* for a 745 MMBtu boiler. Even calculated using the suspect NCASI factors, the total HAPs emissions for the facility would have been more than twice that amount.

The industry-supplied emission factor for HCl likely underestimates actual emissions

Are the NCASI emission factors credible? To evaluate this question, we analyzed actual emissions of hydrochloric acid (HCl) from currently operating plants.[81] We focused on HCl because it is emitted by biomass burning in large quantities, and can thus push a facility over the threshold from being an area source to a major source of HAPs. The AP-42 emission factor for HCl is 0.019 lb/MMBtu (1.9E-02 using scientific notation). Using EPA's emissions factor, a 121 MMBtu boiler (approximately, an 8 MW facility) would have the potential to emit ten tons of HCl per year, and would thus be a major source for HAPs. In contrast, the NCASI emission factor for HCl is 0.00067 lb/MMBtu (6.7E-04), just 3.5% the EPA's AP-42 value. A boiler would have to be 2,840 MMBtu (199 MW) to have a PTE of ten tons per year using the NCASI factor. This is far larger than any facility in our database.

Analysis of actual HCl emissions data suggests the industry-supplied emissions factor under-represents emissions at typical biomass plants

To determine which emissions factor is more representative of HCl emissions from currently operating facilities, we averaged data for the 46 facilties for which EPA has collected recent test data on HCl emissions, grouping data by the year in which the data were collected,[82] and arranged the averages by percentiles (Table 9). Our analysis suggests that the NCASI emissions factor significantly underrepresents typical HCl emissions at most biomass plants. The median and average emission rates of HCl for the EPA dataset are 1.00E-03 and 8.00E-03 lb/MMBtu, respectively 200% the value of NCASI's reported median of 5.0E-04 lb/MMBtu, and 1,194% of the NCASI average of 6.7E-04 lb/MMBtu. In fact, the NCASI median and average emission factors for HCl are both lower than the 30th percentile of the recent EPA test data, as seen from the actual distribution of HCl emissions from the EPA dataset.[83] This strongly suggests that the NCASI factor under-represents HCl emissions at currently operating plants.

---

[81] EPA called for information on actual emissions to assist in formulating the boiler rule. The database is, Draft Emissions Database for Boilers and Process Heaters Containing Stack Test, CEM, & Fuel Analysis Data Reported under ICR No. 2286.01 & ICR No. 2286.03 (version 8) May, 2012. Available at http://www.epa.gov/airtoxics/boiler/boilerpg.html (database labeled "Boiler MACT Draft Emissions and Survey Results Databases")

[82] Three of the facilities were represented by three years of data; eight were represented by two years of data.

[83] It is interesting to note that since EPA published its new dataset, NCASI has updated its set of emissions factors. The group claims that the new data were integrated with existing data using an "elaborate statistical procedure".

Table 9. The NCASI emission factor for HCl under-represents emissions at operating plants

Percentile	HCl EF (lb/MMBtu)
10th Percentile	1.60E-04
20th Percentile	2.89E-04
30th Percentile	**1.00E-03**
40th Percentile	1.00E-03
50th Percentile	1.00E-03
60th Percentile	3.00E-03
70th Percentile	7.00E-03
80th Percentile	1.30E-02
90th Percentile	2.30E-02
95th Percentile	3.70E-02
99th Percentile	8.20E-02
Average	**8.00E-03**

Table 9. Percentile distribution of HCl emission rates for 46 bioenergy facilities in EPA's emissions database. [84] The median and average values reported for the NCASI dataset are both lower than the 30th percentile value.

Is the NCASI emissions factor so low because it is based on emissions data from plants are using a sorbent system to neutralize HCl? We examined the EPA's data to see if using a sorbent system made a difference. While it is likely that a number of facilities in the EPA's HCl emissions dataset use sorbent to neutralize HCl emissions, there is no clear way to determine all that do. However, even facilities that are clearly marked in the EPA dataset as using an acid gas sorbent system can still have emissions that exceed the NCASI emissions factor. For instance, two wood-burning biomass plants, **Covanta's Medota and Delano facilities in California**, both use acid gas sorbent systems. The average HCl emissions rate reported to EPA for the Delano plant was 7.14E-03,which is <u>1,065% the NCASI average</u>. The average rate for the Mendota plant was 2.65E-02, which is <u>3,950% the NCASI average</u>.[85] This indicates that even when plants use sorbent systems, their emissions can exceed the NCASI estimate.

Our permits database contains permits for facilities that claim to be area sources for HCl, yet do not propose to use any acid control at all, suggesting their emissions could be elevated and that if they used the NCASI emissions factors to estimate future emissions, they have probably under-estimated. For instance, the proposed **24.9 MW (net) Biogreen Sustainable Energy plant in**

---

[84] Draft Emissions Database for Boilers and Process Heaters Containing Stack Test, CEM, & Fuel Analysis Data Reported under ICR No. 2286.01 & ICR No. 2286.03 (version 8) May, 2012. Available at http://www.epa.gov/airtoxics/boiler/boilerpg.html (database labeled "Boiler MACT Draft Emissions and Survey Results Databases")

[85] The data for these two plants are notated as "new test data submitted by Biomass Power Association."

La Pine, Oregon, used the NCASI factor to estimate its HCl emissions, claiming to be an area source for HAPs. The plant is not going to use any sorbent system for HCl, even though up to 20% of its fuel will be construction and demolition wood.[86] This suggests this facility should acutally be regulated as a major source for HAPs.

The AP-42 HCl emissions factor of 0.019 lb/MMBtu (1.9E-02), which is based on the average of older data collected by the Agency, falls between the 80th and 90th percentiles of the new set of EPA emissions data that we analyzed, suggesting that it is a relatively protective factor that adequately characterizes emissions of many new facilities. Since so many facilities are being permitted without a sorbent system to reduce HCl emissions, the need to estimate emissions using properly conservative factors is even greater.

Overall, the evidence suggest that the NCASI emission factor for HCl significantly underestimates HCl emissions at most facilities. Of the 88 facilties in our permit database, all but three had boilers that were greater than 121 MMBtu in capacity, meaning that if their emissions had all been calculated using the EPA's AP-42 factor, <u>all these facilities would have been regulated as major sources for hazardous air pollutants on the basis of their potential to emit HCl emissions alone</u>. When states issue permits and allow permit applicants to pick and choose what emissions factors to use for air toxics, including the low-ball NCASI factor for HCl, the result is that facilities are erroneously permitted as "area" sources under the boiler rule.

Loophole 6: Weak testing requirements mean air toxics limits aren't enforceable

Once a facility that has been permitted as an area source for HAPs is operating, lax to non-existent testing requirements for air toxics mean it may be able to exceed allowable emissions thresholds and pollute with impunity. While facilities that avoid PSD by declaring themselves minor sources for criteria pollutants are required to at install continuous emissions monitors (CEMs) for a few criteria pollutants such as NOx and CO, there is almost no monitoring required for emissions of hazardous air pollutants, and thus no way to ensure that permit limits are or can be enforced. Some permits require facilities to perform one-time stack tests for certain air toxics 180 days after startup, then possibly once every few years thereafter, although this is not always enforced. For example, although the **wood- and garbage-burning 33 MW(gross) Evergreen Community Power facility in Reading, Pennsylvania** started operation on August 17, 2009, the plant still had not conducted required stack testing for dioxins, metals, HCl, PM, NOx, SOx, and other pollutants[87] as of September 2011, more than two years later, due to

Facilities are supposed to estimate all emissions of air toxics when claiming minor source status, but few do

[86] Oregon Department of Environmental Quality, Eastern Region. Standard air contaminant discharge permit review report for Biogreen Sustainable Energy Co., LLC. Permit No. 09-9557-ST-01.
[87] Required pollutant tests from letter to Mr. Cliff Heistrand, Evergreen Community Power, from George N. Liddick, Pennsylvania Department of Environmental Protection, June 1, 2009.

malfunctions.[88] The facility had also not been keeping track of emissions of criteria pollutants,[89] as required by federal law. Nonetheless, the plant was allowed to keep operating (see below for more details on malfunctions and violations at the Evergreen facility).

In the biomass power plant permits we reviewed, a lack of accountability for HAPs emissions was the norm. The lax nature of biomass air permitting has been rarely challenged in a formal way before EPA, but petitioners to EPA on the **23.8 MW (gross) Hu Honua coal to biomass conversion in Pepe'ekeo, Hawaii,** did receive some satisfaction from the Agency. In the EPA's response to the citizen petition protesting the lax nature of the Hu Honua air permit, EPA states *"To effectively limit Hu Honua's individual HAP and total HAP PTE to less than 10 and 25 tpy, respectively, as specified, the individual and total HAP emission limits in Section C.7 of the Final Permit must apply at all times to all actual emissions,* ***and all actual individual and total HAP emissions must be considered in determining compliance with the respective limits****"*[90] (emphasis added). EPA is saying here that the permit must contain requirements for the facility to examine actual HAPs emissions in a comprehensive way – meaning testing – for the permit to be enforceable.

The EPA Hu Honua decision is significant, because it appears that a number of the permits we reviewed do not include enforceable limits for HAPs. For instance, the permit for the **54.5 MW (net) Piedmont Green Power in Barnesville, Georgia,** requires a one-time stack test for HCl to estimate monthly emissions, but for HAPs other than HCl, emissions are calculated based on emission factors for HAPs "as approved by the Division" (i.e., the Georgia Environmental Protection Division). No stack testing is required. The Piedmont plant was awarded a $49.5 million cash grant from the federal government in "clean energy" funding, but the program apparently does not check whether permits are legal and enforceable before awarding funding.[91]

Many of the biomass plant permits we reviewed do not appear to contain enforceable limits for air toxics, potentially rendering them invalid

The permit for the **42 MW (net) conversion of an oil/gas boiler at the Montville Power plant in Uncasville, Connecticut** allowing the plant to burn biomass provides another example of apparently unenforceable permit limitations on hazardous air pollutants. The plant will be allowed to burn a variety of waste wood, increasing the likelihood it will be a significant source of metals and other HAPs. While the permit states that the Permittee "*shall not cause or allow emission from this equipment to exceed the maximum allowable stack concentration (MASC) for any pollutant listed in RCSA §22a-174-29*," thus referencing a long list of allowable emissions for air toxics regulated in

---

[88] Pennsylvania Department of Environmental Protection Air Quality Program. Inspection report for United Corrstack, LLC, conducted September 29, 2011.
[89] Ibid.
[90] United States Environmental Protection Agency. In the matter of Hu Honua Bioenergy Facility, Pepeekeo, Hawaii. Permit No. 0724-01-C. Order responding to petitioner's request that the Administrator object to issuance of state operating permit. Petition No. IX-2011-1. Page 17.
[91] The Piedmont facility has received a "Section 1603b" grant, which converts the incentive tax credit, worth 30% of construction costs, to a cash award. Grantees are listed at
http://www.treasury.gov/initiatives/recovery/Documents/Section%201603%20Awards.xlsx

Connecticut, the permit only requires stack testing for HCl and ammonia.[92] In contrast, the permit for the **37.5 MW (net) Plainfield Renewable Energy plant in Plainfield, Connecticut**, which will burn "sorted" construction and demolition wood, states "*The Permittee shall demonstrate compliance for each and every hazardous air pollutant emitted from this unit*" that is listed in three tables of the RCSA document, and that emission rates will be calculated using continuous emissions monitoring for certain pollutants and "*initial and annual stack testing (or fuel testing) for all other pollutants*."[93] However, that permit also states that the only stack tests for HAPs that are *really* required are tests for a small handful of HAPs that are listed directly in the permit.[94] In this case, although the permit does at least require testing, its provisions still appear to be contradictory and unenforceable.

Neither of the Title V permits for two biomass energy plants in New York, the **19 MW (net) ReEnergy Lyonsdale Biomass plant in Lyonsdale,** and the **50 MW(net) ReEnergy Black River plant at Fort Drum,** include firm testing and compliance requirements for HAPs. Both simply state, *"For the purpose of ascertaining compliance or non-compliance with any air pollution control code, rule or regulation, the commissioner may require the person who owns such air contamination source to submit an acceptable report of measured emissions within a stated time."*[95] Yet both facilities claim synthetic minor status for HAPs.

Representative of the woefully inadequate state of air permitting for bioenergy is the permit for the **58 MW (gross) ecoPower plant proposed in Hazard, Kentucky**. An early summary of the permit[96] declared that the facility would emit 35 tons of HAPs, putting it over the 25-ton annual threshold and thus making it a major source subject to the major source MACT standard. Evidently, the company objected, because the summary of the final permit[97] states that the *total* emissions of all HAPs from this large 745 MMBtu/hr boiler will now be less than ten tons annually. Further, even the minimal requirement for one-time stack testing for emissions of the main HAPs emitted by biomass burning, including benzene and formaldehyde, [98] was stripped from the final permit. This company cherrypicked their own emissions factors to estimate total HAPs emissions,

---

[92] Connecticut Department of Energy and Environmental Protection. Bureau of Air Management. New Source Review Permit for Montville Power, LLC. Modification issue date May 20, 2013; Prior issue date April 6, 2010.

[93] Connecticut Department of Energy and Environmental Protection. Bureau of Air Management. New Source Review Permit for Plainfield Renewable Energy LLC. Permit modification date December 8, 2011.

[94] Connecticut Department of Energy and Environmental Protection. Hazardous Air Pollutants, RCSA §22a-174-29. Available at http://www.ct.gov/deep/cwp/view.asp?a=2684&Q=322184&deepNav_GID=1619

[95] New York State Department of Environmental Conservation. Air Title V Facility Permit for Lyonsdale Biomass, Permit ID 6-2338-00012/00004. Effective date 08/16/2011; and, New York State Department of Environmental Conservation. Air Title V Facility permit for ReEnergy Black River, LLC. Permit ID: 6-2240-00009/00007. Effective date 5/20/2013.

[96] Commonwealth of Kentucky Division of Air Quality Permit Application Summary Form, for ecoPower Generation, LLC. Version marked "Application received 1/7/2010".

[97] Commonwealth of Kentucky Division of Air Quality Permit Application Summary Form, for ecoPower Generation, LLC. Version marked "Application received December 21, 2012".

[98] This provision, found in the draft of the permit dated 6/26/09, stated "During the initial stack testing, the permittee shall determine emission factors for hydrogen chloride, benzene, chlorine, and formaldehyde. The emission factors from stack testing shall be used to demonstrate that emissions of any single HAP do not exceed 9 tons per 12 consecutive months, and that total potential emissions of HAPs do not exceed 22.5 tons per 12 consecutive months. These emission factors shall be valid for the life of the permit unless directed otherwise by the Division [401 KAR 52:020, Section 26]."

not using the NCASI factors, but inventing their own. Nonetheless, typically for bioenergy company rhetoric, the company's website states, "ecoPower is creating a new, clean and renewable source of electricity known as 'bioenergy.'[99]

It is likely that if the requirements imposed by the EPA decision on the Hu Honua facility were applied to other plants – i.e., that once operating, facilities should use *actual* emissions of HAPs, including during startup and shutdown, to determine whether they are complying with the requirement to stay below the 10/25 ton threshold – <u>almost none of the biomass power plants now claiming "synthetic minor" status for HAPs would be able to comply</u>. What saves these facilities from having to comply with air quality laws, however, is that EPA is ignoring the majority of state-level bioenergy permits currently being issued.

Fuel contaminant testing requirements are even more rare

Testing fuels before they are burned to determine whether their combustion will emit toxic air pollution is one way to increase compliance with permitted emissions limits. However, in our review of tens of permits, we rarely found requirements that fuel be tested, and when there was a requirement, it was so lax as to be almost meaningless. For instance, the permit for the proposed **60 MW (gross) Loblolly Green Power plant in Newberry, South Carolina** states that the plant will burn "*clean, untreated wood waste*," and that "*an initial fuel analysis or stack testing will be conducted. No additional analysis will be required, unless the clean, untreated wood becomes inconsistent in composition or is received from another source*."[100] However, the document does not explain how a determination that fuel has become "inconsistent in composition" is to be made if testing is not required.

Fuel testing requirements at the **50 MW(net) ReEnergy Black River plant at Fort Drum, NY**, highlight the difficulty of characterizing fuel contamination in a statistically meaningful way. The facility's permit states that it can burn "*clean wood, unadulterated wood from C+D debris, glued wood creosote treated wood (sic), tire derived fuel and non-recyclable fibrous material (waste paper)*." To determine the amount of contaminated wood burned, the permit states, "*ReEnergy shall employ the "grid test" which consists of a 10 by 10 grid placed over the wood stream and checked to determine the percentage of glued wood, treated/painted wood, and non-wood materials. If it is determined that the percentage of glued wood is between 0 and 1.0% by volume, then the percentage of glued wood for that load is 1%. If it is determined that the percentage of glued wood is between 1% and 20% by volume, the percentage of glued wood for that load is 20%. If it is determined that the percentage of glued wood is greater than 20% by volume,*

Although many biomass facilities are permitted to burn waste-derived fuels, few actually test to determine contamination levels

[99] http://www.ecopg.com/

[100] Loblolly Green Power Statement of Basis, Permit number 1780-0051CA. South Carolina Department of Health and Environmental Control, September 3, 2009.

then the load is considered to 100% glued wood. This method shall be employed once every 5 loads per supplier." [101]

As tractor-trailer loads of wood are typically 20 – 22 tons, this method of checking the "wood stream" (presumably the material being fed to the plant on the conveyor belt) is likely to characterize only a tiny fraction of the material burned. Even done properly, such tests are unlikely to be representative; and it seems unlikely that adequate oversight will occur. As we discuss below, new rules proposed by EPA are likely to increase burning of construction and demolition (C&D) waste while removing any requirement for testing at all.

Contaminated wastes burned as biomass: EPA declines to regulate

The bioenergy industry is growing fast, and looking for new sources of fuel. Construction and demolition debris, as well as municipal and industrial wastes, are especially attractive fuels given their disposal often generates "tipping fees" that can constitute a significant portion of a biomass power plant's income. For instance, the **25 MW (net) Taylor Biomass plant, a wood and garbage-fueled power plant proposed in Montgomery, New York**, estimates that tipping fees for wastes range from $50/ton to over $80/ton, and a 2008 IRS evaluation of the facility's eligibility for tax credits[102] reports that Taylor anticipated receiving $50 for each ton of MSW it received. The Taylor project was permitted under rules governing municipal waste incinerators, though their name suggests they are a biomass plant. [103]

For the purposes of distinguishing "waste" from "biomass," EPA relies on a part of the Resource Conservation and Recovery Act (RCRA) known informally as the "waste rule."[104] As part of determining whether a material is a waste, EPA compares contaminant levels in the material to those in "traditional" fuels. An early draft of EPA's waste rule, from March 2011, explains: "*non-hazardous secondary materials (NHSM) that contain contaminants that are not comparable in concentration to those contained in traditional fuel products or ingredients would suggest that these contaminants are being combusted as a means of discarding them, and thus the non-hazardous secondary material should be classified as a solid waste*."[105]

This definition is problematic for the expanding bioenergy industry. Under the Clean Air Act and court precedent, any facility that burns any solid waste at all is an incinerator and must meet incinerator emission standards, which are, as discussed previously, somewhat more restrictive than those applicable to conventional biomass boilers (Table 7). Further, "waste incineration" doesn't

---

[101] New York State Department of Environmental Conservation. Air Title V Facility permit for ReEnergy Black River, LLC. Permit ID: 6-2240-00009/00007. Effective date 5/20/2013.

[102] Internal Revenue Service. Letter ruling on qualification of Montgomery LLC for federal for tax credit. June 11, 2008.

[103] Our report on the Taylor facility, which evaluates claims made by the company in its application for a $100 million "clean energy" loan guarantee from the US Department of Energy, is available at http://www.pfpi.net/wp-content/uploads/2013/05/PFPI-Gasification-and-DOE-loan-guarantees.pdf.

[104] The current version of the rule, and amendments, are available at http://www.epa.gov/epawaste/nonhaz/define/index.htm

[105] 40 CFR Part 241. Identification of non-hazardous secondary materials that are solid waste; proposed rule. Federal Register Vol. 75, NO. 107. Friday, June 4, 2010. p. 31871

sound green and renewable, whereas "biomass power" does. A letter from **Michigan Biomass, an advocacy group working on behalf of six biopower plants[106] in Michigan,** filed in EPA's waste rule docket, explains the bioenergy industry's problem:

"*Waste wood from the pulp and paper and forest products industries is the major source of biomass fuel for these facilities. However, for nearly a decade, these industries have been in decline, drastically reducing the wood available for fuel. Because of this, alternative fuels have played a significant role in offsetting the constrained wood fuel supply. This will only grow tighter as the state's new energy policy promoting biofuels production and incentivizing new biomass-fueled power production puts increasing demand on this limited resource. The ability to fire alternative fuels with our main forest-based wood fuel is imperative to the survival of these projects in this new energy landscape.*

Biomass industry to EPA: "There is a stigma attached to being classified as an incinerator that plants will want to avoid"

Being regulated as incinerators would represent a regulatory burden to power plants that utilize wood as a fuel and could kill the legitimate reuse of materials that work well as fuel in traditional power plant boilers. Additionally, there is a stigma attached to being classified as an incinerator that plants will want to avoid. It is likely a facility will cease using a material as a fuel if it means they will be classified as an incinerator. Limiting the use of such fuel will jeopardize the viability of these plants and more material will be sent to landfills or open burned."[107]

Because biomass burners are usually eligible for renewable energy subsidies and tax breaks, whereas incinerators may not be, it's clear that the stigma of being classified as an incinerator may have actual financial consequences.

Many biomass plants plan to burn contaminated waste materials as fuel

Many of the biomass power plants currently being developed plan to burn waste wood as fuel. An industry database of operating and proposed bioenergy plants lists 54 facilities that burn, or plan to burn, "urban wood," which often includes construction and demolition wood and other potentially contaminated waste wood, such as railroad ties.[108] Of the permits in our database, the majority (61 permits, 69%) allowed burning of some kind of waste wood besides forest and mill residues, with many explicitly stating that construction and demolition debris would be burned. While some of these permits are for plants that have subsequently been cancelled, and some plants won't be built, the high percentage of total permits that allow waste wood burning indicates how widespread this practice has become. Of those 60 permits that allow burning waste wood, 38 (63%) are clearly claiming area source status under the boiler rule, meaning they will only be required to meet the

---

[106] The six plants represented by Michigan Biomass are Cadillac Renewable Energy, in Cadillac; Genesee Power Station, in Flint; Grayling Generating Station, in Grayling; Hillman Power Company, in Hillman; Lincoln Power Station, in Lincoln; and McBain Power Station, in McBain.

[107] Letter from Tamra S. Van Til, representing Michigan Biomass, to EPA: Comments on advanced notice for rulemaking, docket ID# EPA-HQ-RCRA-2008-0329, Identification of non-hazardous materials that are solid waste. February 2, 2009.

[108] Forisk, Wood Bioenergy US database, December, 2013

relatively high filterable PM standard of 0.03 lb/MMBtu, with no limits on HCl, dioxins, mercury, or other heavy metals, even as they burn potentially contaminated fuels.

Some plants will be fueled almost exclusively by waste wood. The **37.5 MW (net) Plainfield Renewable Energy plant in Plainfield, Connecticut** is permitted to burn up to 495,305 tons per year of wood, including "waste wood from industries" and construction and demolition waste. The wood is supposed to be sorted to remove materials like plastics, gypsum wallboard, and "*wood which contains creosote or to which pesticides have been applied or which contains substances that have been defined as hazardous*,"[109] but it is not clear how effective such sorting can be, given that the sorting facilities rely on visual inspection to remove contaminated materials from a fast-traveling conveyor belt loaded with tons of debris. Any testing program to check for contamination is bound to be statistically invalid, given that on average the Plainfield plant will burn more than 60 tractor-trailer loads of wood chips per day. In Massachusetts, the state commissioned a health risk assessment for burning "sorted" construction waste after a construction and demolition debris burner was proposed for the city of Springfield, citing concerns about emissions of heavy metals and other hazardous air pollutants,[110] but Connecticut has commissioned no equivalent study.

The majority of "area" source permits, which lack any emissions limits for air toxics, allow potentially contaminated waste wood as fuel.

Many other facilities will depend on at least some waste wood, even when forestry wood is apparently available. Two biomass cogeneration expansion projects associated with paper mills on the Olympic Peninsula in Washington, the **20 MW (net) Nippon Paper facility at Port Angeles**,[111] and the **24 MW (net) boiler at the Port Townsend Paper Company plant**,[112] will both burn waste wood as fuel, along with forestry wood (the Nippon facility also burns wastewater-treatment sludge from the paper-making process).

Why would biomass facilities want to burn contaminated fuels? There are a number of reasons. Pass-through of tipping fees for waste disposal to biomass power plants can produce a lucrative revenue stream for a facility. In some cases, facilities may fear that "clean" wood sources are limited, or might become more distant over time , increasing transportation costs. Finally, certain waste fuels burn hotter and produce more energy than green forestry chips. Construction and demolition-derived wood tends to be drier, which increases its heating value per unit mass, and paper-based and especially plastic-based fuels can have significantly higher heating values than wood – for instance, the proposed **25 MW (net) Taylor Biomass plant, a wood and garbage-**

[109] Connecticut Department of Energy and Environmental Protection. Bureau of Air Management. New Source Review Permit for Plainfield Renewable Energy LLC. Permit modification date December 8, 2011.

[110] This study was not completed because the developer of the Palmer Renewable Energy plant in Springfield elected to reapply as a facility that would only burn "clean" wood derived directly from trees, rather waste wood.

[111] Olympic Region Clean Air Agency. Order of Approval – Notice of Construction 10NOC763, Issued to Nippon Paper Industries USA Co. Ltd. June 21, 2011.

[112] Washington Department of Ecology. Notice of Construction for Port Townsend Paper Corporation, NOC Order No. 7850. October 22, 2010.

fueled power plant proposed in Montgomery, New York depends on plastics in fuel to generate sufficient energy for the gasification process they plan to use.[113]

Shredded tires are another attractive fuel that is seen as integral to the success of the proposed **25 MW North Star Jefferson wood-tire burner proposed in Wadley, Georgia,** where the developer states that "*TDF is important to the financial viability of the project given its high caloric content as evidenced by its use in various industries such as pulp and paper production, cement plants in addition to electricity generation*."[114] The North Star plant avoided PSD and thus did no pre-construction air quality modeling. It will be a significant new source of air pollution in a community that already includes several large polluters, including a lumber mill that is a large source of emissions from burning wood. Developers of the North Star plant include the U.S. Endowment for Forestry and Communities, a non-profit organization that is setting up the for-profit wood and tire-burner to generate revenue and, they say, to revitalize the economy around Wadley.[115]

Loophole 7: EPA rules blur the line between biomass facilities and incinerators

The bioenergy industry needed EPA to redefine wastes as legitimate fuels, because for biomass plants where the "traditional fuel" is unadulterated forest wood, the waste rule's requirement that "non hazardous secondary materials" (NHSM) contain no more contamination than traditional fuels[116] might be assumed to exclude most contaminated materials. EPA's response, which has been to define "traditional fuel" as any fuel a facility *might* burn, even a very dirty coal, has been more than satisfying to the bioenergy industry and other facilities that burn contaminated fuels. The EPA's latest waste rule is explicit – a facility can burn contaminated fuels, including construction and demolition wood, as long as concentration levels of contaminants are "*comparable to or less than the levels in the traditional fuel the unit is designed to burn, whether wood or another traditional fuel*,"[117] and that "*Designed to burn*" means, "*can burn or does burn, and not necessarily permitted to burn*."[118] This includes coal. The rule clarifies further: "*The agency has also determined that restricting comparisons to traditional fuels the unit is permitted to burn is unnecessary. The fact that a facility is not currently permitted to burn a particular traditional fuel does not mean it could not be permitted to burn that traditional fuel in the future. For this reason, we do not believe it is reasonable to limit the comparison to permitted traditional fuels*."[119]

EPA's waste rule classifies contaminated materials as "non-hazardous," allowing them to be burned as biomass

[113] Our report on Taylor Biomass is available at http://www.pfpi.net/wp-content/uploads/2013/05/PFPI-Gasification-and-DOE-loan-guarantees.pdf.
[114] http://northstarrenewable.com/index.php/projects/north-star-jefferson/faqs
[115] http://usendowmentblog.blogspot.com/2011/12/working-not-where-light-is-best-rather.html
[116] Because the rule requires comparing contamination on a material weight basis, not a material energy content basis, a biomass facility can burn a "less contaminated" material and still emit more air toxics than a same-sized coal plant, because the low efficiency of bioenergy requires burning more fuel to produce the same amount of energy.
[117] 40 CFR Parts 60 and 241. Commercial and industrial solid waste incineration units: reconsideration and final amendments; non-hazardous secondary materials that are solid waste. Federal Register Vol. 78, No. 26, Thurs. February 7, 2013. p. 9139.
[118] Ibid, p. 9136
[119] Ibid, p. 9149

EPA rules compare contaminant concentrations in biomass to the dirtiest coal
What if the biomass a company wants to burn is so contaminated, they can't find a coal dirty enough to compare to? The waste rule can accommodate that situation, stating: "*Persons who would otherwise burn coal may use any as-burned coal available in coal markets in making a comparison in their NHSM and the contaminants in coal – they are not limited to coal from a specific coal supplier they have used in the past or currently use*." And, while "*national surveys of traditional fuel contaminant levels are one example of another acceptable data source*,"[120] it's also fine to compare to dirty coals internationally: "*a statement that national surveys can be used does not preclude the use of appropriate international data*."[121]

Incredibly, the EPA seems quite sanguine about the implications of these provisions, stating, "*The EPA acknowledges that the revisions adopted as final in today's rule would allow C&D wood contaminant levels to be compared to the highest contaminant levels for coal*."[122]

EPA explicitly acknowledges that rule revisions "allow C&D wood contaminant levels to be compared to the highest contaminant levels for coal"

We found a large number of facilities in our permits database that list potentially contaminated materials as fuel. One permit stands out for having cited the new rule allowing use of fuels that are as contaminated as coal – the **proposed 25 MW wood and tire-burning North Star Biomass project, in Wadley, Georgia.** In its application for an air permit, the company proposed to burn agricultural waste, animal waste, construction and demolition waste, wood, and tire-derived fuel, stating stated that their fuels would be no more contaminated than coal. The Georgia air permitting branch of the Environmental Protection Division (EPD) did ultimately restrict the facility to burning "clean" wood and tire-derived fuel after the community protested, but cited the new EPA rule allowing fuels to be as contaminated as coal as justification for inclusion of tires in the fuel stream: "*Although the permitted fuels for the boiler are wood biomass and TDF, the traditional fuel with which TDF is compared (coal) can be burned in the fluidized bed boiler. This has been confirmed by the boiler vendor - Premier Energy. The 'designed to burn' provision of the legitimacy criteria is based on what the respective boiler is capable of burning, not what it is permitted to burn or intended to burn. Because the boiler is capable of burning coal, the "designed to burn" provision of the legitimacy criteria is met*."[123]

During the permitting process, the company and the Georgia EPD dismissed comments pointing out that burning tires emits a large number of extremely toxic substances, and chose to calculate toxic emissions based on just a subset of the hazardous air pollutants known to be emitted. The company claimed that air toxics emitted by open burning of tires would *not* be emitted when tires were burned in a boiler, but presented no evidence to that effect.[124] Overall, considering the way

[120] Ibid, p. 9144
[121] Ibid, p. 9153
[122] Ibid, p. 9152
[123] Alaa-Eldin A. Afifi, Georgia Environmental Protection Division, Air Protection Branch. Permit narrative for North Star Jefferson Renewable Energy Facility, page 22. May 2, 2012.
[124] Response to public comments on draft permit and permit application no. 20770, North Star Jefferson Renewable Energy. Letter to Eric Cornwell, Manager, Stationary Source Permitting Program, Air Protection Branch, Georgia Environmental Protection Division, from North Star Jefferson. April 17, 2012.

the Georgia EPD invoked the comparison to coal, the North Star permit demonstrates how little protection communities can expect to receive from EPA and state-level permitting agencies when a biomass facility decides it is going to burn contaminated fuels. Communities should consider themselves lucky to even know what materials the facility will burn, since the EPA's rules open the door to so many potentially contaminated materials.

EPA takes industry's word that biomass fuels are "clean" – testing not required

Processing waste materials to reduce contamination is one way to meet EPA's "legitimacy criteria" for classifying a material as a non-hazardous fuel, rather than a waste. The first step for processing is generally visual inspection – waste is tipped out onto a sorting room floor and workers manually sort through it to remove household hazardous waste, e-waste, and other contaminated materials such as PVC pipe that can emit high levels of toxics when burned.[125] With construction and demolition debris, visual sorting is the means of removing pressure treated and otherwise contaminated wood.

Removal of contaminated materials from the fuel stream relies primarily on visual inspection

Although such sorting is prone to a high error rate, EPA nonetheless states that "*In general, contaminated C&D wood that has been processed to remove contaminants, such as lead-painted wood, treated wood containing contaminants, such as arsenic and chromium, metals and other non-wood materials, prior to burning, likely meets the processing and legitimacy criteria for contaminants, and thus can be combusted as a non-waste fuel*."[126]

The line of reasoning that once it is processed, "waste is not waste" was employed by a court in Washington as a reason for denying an effort to require an environmental impact report for the **24 MW Port Townsend Paper biomass expansion project in Washington**. Citizen groups wanted the state to require an environmental impact assessment of the project, which will burn waste materials, emit large amounts of greenhouse gases, and potentially impact forests where logging occurs to provide fuel for the plant. The court responded that a Washington law requiring that "*No solid waste incineration or energy recovery facility shall be operated prior to the completion of an environmental impact statement*" didn't actually apply to the facility, in part because it will not be an "energy recovery facility" for solid waste. Solid waste is defined as "*all putrescible and nonputrescible solid and semisolid wastes including, but not limited to, garbage, rubbish, ashes, industrial wastes, swill, sewage sludge, demolition and construction wastes, abandoned vehicles or parts thereof, and recyclable materials*". However, the court determined that hog fuel, urban wood, and burnable rejects from the mill and container recycling facility are *not* solid waste, because they have "become a

[125] The EPA comfort letters sent to companies manufacturing fuel cubes from garbage and other wastes describe the processing steps as the waste is "transformed" into a non-hazardous secondary material. These letters are available at http://www.epa.gov/epawaste/nonhaz/define/

[126] 40 CFR Parts 60 and 241. Commercial and industrial solid waste incineration units: reconsideration and final amendments; non-hazardous secondary materials that are solid waste. Federal Register Vol. 78, No. 26, Thurs. February 7, 2013. p. 9138

commodity" – therefore, the facility is not actually an energy recovery facility, because it won't actually burn solid waste.[127]

EPA rules allow potentially contaminated biomass fuels to escape testing

The waste rule and its implementation are seen as a disaster by many who are concerned about toxic emissions. In its response to comments on the rule, EPA acknowledges concerns that fuel testing should be required, given the potential for contaminated materials to slip through the sorting process. The rule states that "*there will be instances where testing is conducted and comparisons will have to account for the variability of contaminant levels in NHSMs, including lead concentrations in C&D wood,*"[128] implying one-time testing for initial fuel characterization, rather than ongoing testing. However, "*contaminant testing is not required in all situations. Requiring testing in some situations is unnecessary*."[129] Instead, "expert opinion" is sufficient: "*contaminant legitimacy criterion determinations do not require testing contaminant levels, in either the NHSM or an appropriate traditional fuel. Persons can use expert or process knowledge to justify decisions to either rule out certain constituents or determine that the NHSM meets the contaminant legitimacy criterion.*"[130] EPA adds, "*The agency wishes to emphasize, that determinations that the cellulosic biomass used as a fuel or ingredient is clean, do not presuppose any testing of contaminant levels. Persons can use expert or process knowledge of the material to justify decisions regarding presence of contaminants*."[131]

EPA: construction and demolition-derived wood too clean to monitor?

That construction and demolition wood (CDD) can contain lead-painted wood, copper-chromium-arsenate (CCA)-treated wood, glued woods, asbestos, mercury waste, and other materials that result in toxic emission when burned is well known. Contaminated wood constitutes around 20% of the growing supply of construction and demolition wood generated by housing tear-downs and by storms.[132] This material can contain large amounts of heavy metals – for instance, one study estimated that wood debris generated after Hurricane Katrina contained 1,890 tons of arsenic.[133]

Initially, the draft waste rule included pressure-treated wood as a material where contaminant levels are high enough that combustion may be occurring as a means of disposal, stating "…*non-hazardous secondary materials that may not contain comparable concentrations of contaminants include*

[127] Pollution Control Hearings Board, State of Washington. PCHB No. 10-160 Order on Summary Judgment. PT Air Watchers, No Biomass Burn, World Temperate Rainforest Network, Olympic Environmental Council, and Olympic Forest Coalition, Appellants, v. State of Washington Department of Ecology and Port Townsend Paper Corporation, Respondents. May 10, 2011.
[128] 40 CFR Parts 60 and 241. Commercial and industrial solid waste incineration units: reconsideration and final amendments; non-hazardous secondary materials that are solid waste. Federal Register Vol. 78, No. 26, Thurs. February 7, 2013. p. 9152
[129] Ibid, p. 9152
[130] Ibid, p. 9144
[131] Ibid, p. 9139
[132] Dubey, B., et al. 2007. Quantities of arsenic-treated wood in demolition debris generated by Hurricane Katrina. Environmental Science and Technology, 41:5, 1533 – 1536.
[133] Ibid.

chromium-,copper-, and arsenic (CCA)-treated lumber, polyvinyl chloride (PVC) plastics which can contain up to 60 percent halogens (chlorine), lead-based painted wood, and fluorinated plastics."[134]

However, EPA apparently has such confidence in the data submitted by industry on contamination levels in materials that the Agency has announced it is nearly ready to grant a categorical classification of processed CDD wood as "biomass," and remove testing requirements altogether: "*In the March 2011 final rule, we determined that C&D wood that is sufficiently processed can be a non- waste fuel. The Agency has received additional information since the issuance of that rule on specific best management practices used by suppliers/processors of C&D wood. Such practices include processing to remove contaminants. EPA believes the information received to date would tend to support a listing of these materials as a categorical non-waste fuel and expects to propose that listing in a subsequent rulemaking*."[135] As of mid-March 2014, the EPA's proposed rule granting the reclassification is due to be published in the Federal Register.

An "Inside EPA" article additionally states that that the EPA has also been evaluating industry petitions to list preservative-treated wood as categorical non-waste, including one from the American Forest & Paper Association and the American Wood Council seeking a categorical listing for creosote-treated railroad ties, and one from the Treated Wood Council recommending that "treated wood biomass,"' including wood treated with borate-based preservatives, copper-based preservatives, pentachlorophenol, oilborned copper naphthenate and creosote, be considered a non-hazardous secondary material.[136]

Figure 8. A 50 MW bioenergy plant burns the equivalent of a truckload of chips approximately every 20 minutes. Photo credit: NREL.

EPA did acknowledge in the final waste rule that "*chromated copper arsenate-treated wood (CCA wood) would likely have contaminant levels not comparable to traditional fuels*,"[137] suggesting that this material, by itself, should continue to be treated as a waste and require disposal in incineration units with more protective emissions controls. However, in practice EPA leaves the door wide open to burning this material in area source biomass boilers and thus increasing emissions of metals and other air toxics. Even when visually sorted to

[134] 40 CFR Part 241. Identification of non-hazardous secondary materials that are solid waste; proposed rule. Federal Register Vol. 75, NO. 107. Friday, June 4, 2010. p. 31871

[135] 40 CFR Parts 60 and 241. Commercial and industrial solid waste incineration unites: reconsideration and final amendments; non-hazardous secondary materials that are solid waste. Federal Register Vol. 78, No. 26, Thurs. February 7, 2013. p. 9173

[136] "OMB clears EPA's proposed expansion of 'non-waste' fuel list. Inside EPA.com: The Inside Story. Posted March 13, 2014.

[137] 40 CFR Parts 60 and 241. Commercial and industrial solid waste incineration unites: reconsideration and final amendments; non-hazardous secondary materials that are solid waste. Federal Register Vol. 78, No. 26, Thurs. February 7, 2013, p. 9152

remove obviously contaminated materials, the extraordinarily high volume of C&D that is processed for fuel and the dependence on visual inspection to remove contaminated materials means it is inevitable that pressure-treated, painted, and glued woods get into the fuel stream. Once chipped, and delivered in high volume to a bioenergy facility (Figure 8), as a practical matter, there is little chance of detecting contamination before wood is burned.

Further, since unadulterated wood in the waste stream can be recycled for mulch, wood pellets, animal bedding, and particleboard, the most contaminated materials are what is left over for burning – although, in EPA's view, these are the very materials that are ostensibly sorted out of the bioenergy fuel stream and are *not* used for fuel. It seems inevitable that the EPA's proposal to grant a blanket exemption from testing of C&D wood will mean that more of this contaminated material is burned in biomass power plants that have no restrictions on emissions of air toxics. Importantly, this includes many small "thermal only" wood boilers being installed for heat at municipal buildings, schools, campuses, and hospitals – i.e., in close proximity to sensitive individuals including children, the elderly, and the sick. Many of these boilers are too small to even be covered by the area source rule, which only regulates boilers greater than 10 MMBtu/hr. Once contaminated wood is in circulation as fuel, it is likely to end up being burned at these small facilities, which have almost no emissions controls.

Garbage-derived fuels are EPA's new "non-waste fuel products"

Another category of materials newly classified as fuels under the waste rule is municipal and industrial wastes that have been processed into fuel products. EPA's "legitimacy criteria," the requirements that a waste must meet in order to be reclassified as a non-hazardous secondary material (NHSM), include processing of the material to reduce contaminants or improve energy content. Seizing on the opportunities provided by the waste rule, a number of companies are now processing municipal garbage and industrial wastes into compressed fuel cubes (Figure 9 shows a product from International Paper.[138]) Once EPA issues a "comfort letter" approving these materials as non-hazardous, they can be used as a coal or biomass substitute, and burned in units that are regulated as biomass boilers, rather than the more strictly regulated incinerators. EPA's classification of "biomass" burners as including any boiler that burns just 10% biomass means that even if these fuels contain substantial fossil fuel-derived content, for purposes of regulation, units burning them are subject to the very lax boiler rule standards for biomass boilers.

Figure 9. International Paper fuel cubes, made from compressed waste.

EPA's administrative process to "transform" wastes to non-hazardous fuels is quite hands-off. In accordance with the Agency's legitimacy criteria, a company wishing to get a non-waste

[138] Photo from http://www.globalventurelabels.com/the-environment/

determination for a particular material must describe how the materials are processed, and submit its own supporting data on contaminant levels in its product to the EPA. The EPA then reviews these data, comparing data on contaminant levels in the material to a standard set of contamination levels in wood and coal that ranges from the lowest to the highest levels observed, an extraordinary range. If EPA deems contamination levels in the waste-derived fuel are comparable to those in coal (and sometimes even if they are not), the EPA issues a comfort letter to the company approving the reclassification of the material from "waste" to "fuel."

We reviewed several recently issued comfort letters, and concluded that the EPA review process is sloppy.[139] For example, we found that the EPA trusts companies to test and provide data on contaminants they expect to be present, and does not require similar materials to be tested for similar contaminants. Given the high contaminant concentrations presented by EPA as being present in wood, against which the fuel products are supposed to be compared, it seems likely that the Agency has included contaminated wood as the baseline for measurement. However, this represents circular reasoning, as it assumes that contaminated wood is already acceptable as fuel. We also noted that the ranges of values for contaminant concentrations in fuel vary wildly, and that the EPA's estimate for formaldehyde content in wood, against which prospective fuels are compared, is derived from a single unpublished memo from a single industry source.[140]

EPA signs off on a contaminated fuel product: phthalates and fluorine in SpecFUEL

It seems likely that EPA's process for transforming wastes to fuel, carried out far from public view, can easily lead to approval of contaminated materials as fuel. For instance, the waste disposal company **Waste Management makes a product called "SpecFUEL**," which consists of mostly paper and plastic compressed into cubes. The EPA comfort letter[141] to the company states that according to company-submitted data, "*All contaminants in SpecFUEL are comparable to or lower than those contaminants in both coal and wood/biomass with the exceptions of antimony, fluorine, and bis(2-ethylhexl)phthalate. The latter is a synthetic chemical commonly referred to as DEHP and is used as a plasticizer in plastics, resins, consumer products, and building materials*."

EPA has approved waste-derived fuels that contain phthalates, which are known endocrine disruptors

The DEHP that EPA refers to here is commonly known as phthalate, one of a recognized endocrine disrupting class of chemicals that are being phased out in the European Union due to potential health effects, including potential effects on development of reproductive organs in children. EPA's own reference page on DEHP states, "*Animal studies have reported increased lung weights and increased liver weights from chronic inhalation exposure to DEHP. Oral exposure has resulted in*

[139] Available at http://www.epa.gov/epawaste/nonhaz/define/

[140] EPA's memo titled "Contaminant concentrations in traditional fuels: Tables for comparison," dates November 29, 2011 and available at http://www.epa.gov/osw/nonhaz/define/pdfs/nhsm_cont_tf.pdf, cites "Written communication from Tim Hunt of American Forest & Paper Association to Jim Berlow of EPA, July 14, 2011" as the sole source for data on formaldehyde levels in wood.

[141] Letter to Ms. Kerry Kelly, Waste Management, from US EPA Office of Solid Waste and Emergency Response, August 22, 2013. Available at http://www.epa.gov/epawaste/nonhaz/define/

developmental and reproductive effects in rats and mice. A study by the National Toxicology Program (NTP) showed that DEHP administered orally increased the incidence of liver tumors in rats and mice. EPA has classified DEHP as a Group B2, probable human carcinogen."[142]

Although a variety of the waste-derived fuels approved by EPA contain plastics, of the comfort letters we reviewed, the letter about SpecFUEL was the only one that referenced phthalate content. One large source of DEHP is the blue nitrile gloves used for medical exams and other purposes, suggesting that Waste Management may be using medical waste for making its SpecFUEL product. Waste Management reported to EPA that the concentration of DEHP in SpecFUEL cubes is 240 – 1,410 parts per million, but because there are no data on levels of this contaminant in coal or wood to which the SpecFUEL levels could be compared, EPA simply declared that the fuel met the legitimacy criterion for DEHP.

Waste Management also reported the SpecFUEL concentration of fluorine, a toxic substance emitted as hydrogen fluoride gas when burned, as 585 – 1,070 parts per million, significantly exceeding the reported level in coal, which according to EPA's data can reach 178 parts per million (Table 10). However, EPA glossed over the excessive fluorine content when it approved the SpecFUEL product, arguing that because *combined*, concentrations of fluorine and chlorine together were within the ranges found for the most contaminated coals, the high fluorine content in SpecFUEL did not cause it to fail the legitimacy test.

Table 10: Levels of fluorine in SpecFUEL exceed levels in coal

Halogen	Units	Average			Range		
		SpecFUEL[1]	Coal[1]	Wood[1]	SpecFUEL[2]	Coal[2]	Wood[2]
Chlorine	ppm	2033	992	259	1840 - 2250	ND - 9080	ND - 5400
Fluorine	ppm	892	64	32.4	585 - 1070	ND - 178	ND - 300
Total Halogens[3]	ppm	2925	1056	291	2425 - 3320	ND - 9080	ND - 5497

Notes:
l. SpecFUEL data represents five samples taken on different days in January 2012, provided by Waste Management on March 16, 2012..
2. Data for coal and wood (i.e., clean wood and biomass materials) from a combination of EPA data and literature sources, as presented in EPA document *Contaminant Concentrations in Traditional Fuels: Tables for Comparison,* November 29,2011, available at www.epa.gov/epawaste/nonhaz/define/index.htm.
3 The high and low ends of each individual halogen's range do not necessarily add up to total halogens range. This is because maximum and minimum concentrations for individual halogens do not always come from the same sample.

Table 10. Re-creation of Table 3 ("Contaminant Comparison, Total Halogens Group") from EPA comfort letter to Waste Management, approving use of SpecFUEL as a "non-waste fuel product."

[142] http://www.epa.gov/ttnatw01/hlthef/eth-phth.html

Another concern about burning plastic-based fuels like SpecFUEL is their dioxin emissions. While the incinerator rule sets limits for dioxins, the boiler rule does not regulate dioxins directly (an initial draft of the boiler rule did include direct limits on dioxins, but EPA removed these in the final rule, presumably due to objections from the bioenergy industry). Instead, the major source boiler rule regulates CO emissions as a proxy indicator of incomplete combustion, which can lead to dioxin formation. The CO limits in the major source boiler rule are extremely lax, and in any case, almost irrelevant to the facilities we reviewed, since so few plants admitted to being major sources for HAPs. The area source rule, which regulates the majority of the facilities we reviewed, contains no limit on dioxins *or* CO. The result of EPA's new waste rule is that if waste-derived fuels like SpecFUEL are burned in biomass units, there are no restrictions or accountability for dioxin emissions, or indeed for any HAPs other than HCl. According to the letter from EPA, Waste Management plants to build SpecFUEL plants all over the United States.[143]

Case study of a biomass power plant burning waste: Evergreen Community Power

The **33 MW (gross) Evergreen Community Power/United Corrstack facility in Reading, Pennsylvania** is an example of the kinds of waste-burning biomass projects that EPA rules encourage and the bioenergy industry wishes to promote. This combined heat and power plant associated with United Corrstack, a paper product manufacturing company, cost $140 million to build. It received a $39 million "clean" energy grant from the federal government at startup.[144] An evaluation by the Department of Energy states that the fuel burned at the plant includes mostly wood, but that there are "*significant amounts of paper, plastic and other foreign debris*"[145] (Figure 10[146]). This fuel mix suggests that the facility is actually an incinerator, although for reasons that are unclear, it was not permitted as one. The DOE reported that the facility receives 41 – 55 tractor trailer loads a day of fuel and burns 300,000 – 350,000 tons per year. It generates ~70,000 tons of toxic ash a year, which costs $2.45 million a year for disposal.

Figure 10. The fuel burned at the Evergreen Community Power facility in Reading, Pennsylvania.

[143] Letter to Ms. Kerry Kelly, Waste Management, from US EPA Office of Solid Waste and Emergency Response, August 22, 2013. Available at http://www.epa.gov/epawaste/nonhaz/define/

[144] The guidance for the Department of Treasury's 1603(b) program, which converts the Incentive Tax Credit worth 30% of construction costs to a cash grant, states that the program provides a long-term benefit of expanding the use of clean and renewable energy and decreasing our dependency on non-renewable energy sources." http://www.treasury.gov/initiatives/recovery/Documents/GUIDANCE.pdf

[145] U.S. Department of Energy, Mid-Atlantic Clean Energy Application Center. Evergreen Community Power Plant Case Study: 33 MW Facility Using Biomass. November 16, 2011.

[146] U.S. Department of Energy, Mid-Atlantic Clean Energy Application Center. Evergreen Community Power Plant Case Study: 33 MW Facility Using Biomass. November 16, 2011.

The Evergreen plant is located in the Ozone Transport Region, and federal air permitting applicability thresholds were 100 tons when it was permitted, not 250 tons, but the plant projected emitting no more than 98.7 tons of any pollutant, and thus avoided nonattainment New Source Review permitting. [147] Evergreen was also permitted as an area source for HAPs, even though it was permitted to burn municipal waste, demolition debris, railroad ties, and tire-derived fuel. Projected emissions of HAPs included 9.6 tons of HCl per year (just below the 10 tons per year major source threshold) and a variety of heavy metals, including cadmium, cobalt, chromium, nickel, lead (over a ton per year), manganese, mercury (almost seven pounds per year), arsenic, and selenium. Total HAPs emissions were projected to be 23.9 tons per year, perilously close to the 25-ton triggering threshold that facilities so wish to avoid. [148] The facility started operations in 2009, and by 2010 had seen failure of its ash handling system, its sorbent injection system for controlling HCl, which had to be fully replaced, and its SCR system for controlling NOx. [149] An inspection in 2010 found that the facility had failed to record continuous emissions data for some pollutants, and that the 30-day rolling average emissions rate for HCl, which was supposed to be 0.005 lb/MMBtu to ensure the plant didn't emit more than 10 tons, was actually 30 times higher, at 0.149 lb/MMBtu. [150] This rate, maintained over a year, would lead to emissions of over 300 tons of HCl annually. As of 2010 and 2011, the facility was losing $15 million per year, even though the plant does not pay for fuel, but just its transportation. [151]

Needless to say, this was not how the company had represented its future operations. A write-up about the plant from 2009 looks to the future, quoting David Stauffer, a vice-president of United Corrstack. "*Thanks to reduced emissions, the new plant will improve air quality. 'For every megawatt of electricity we make, that electricity will be displacing a fossil fuel unit somewhere,' Stauffer says. 'When we fire up our 25 megawatts, 25 megawatts of coal fire goes down, which helps clean up the air.*'"[152]

Conclusion: Seven recommendations for seven loopholes

The biomass energy industry is growing rapidly in the United States, but regulation has not kept pace – EPA and the states still treat bioenergy as a boutique industry, requiring special treatment, when in fact the industry is an increasingly large and bullying presence. As we found, bioenergy is disproportionately polluting, both due to physical reasons, and due to loopholes and lax enforcement of the Clean Air Act by localities, states, and the EPA.

---

[147] Plan approval application for the United Corrstack LLC Evergreen Community Power Project. Submitted to the Pennsylvania Department of Environmental Protection, October, 2006.
[148] Ibid.
[149] Letter from Art McLaughlin, Site Manager for Evergreen Community Power, to Kenneth Hartzler, Pennsylvania Department of Environmental Protection, December 28, 2010.
[150] Annual inspection verification report for minor facilities – United Corrstack, LLC. Date of inspection September 29, 2010. Submitted by William Borst, AQDS, to Pennsylvania Department of Environmental Protection.
[151] The facility anticipated receiving $500,000 in tipping fees in its first year of operation, but only collected $10,000.
[152] Ben Franklin Technology Partners website: "United Corrstack: Developing a co-generation plant to provide steam and electricity to its manufacturing facility." May 10, 2009. Accessed January 2014 at http://nep.benfranklin.org/united-corrstack-developing-a-co-generation-plant-to-provide-steam-and-electricity-to-its-manufacturing-facility/

What can be done to reduce the threat of pollution from biomass power? Our analysis identified seven loopholes in clean air laws and their enforcement; here, we suggest how these loopholes can be closed.

<u>Loophole 1: Biomass plants can emit more pollution before triggering federal permitting</u>
The Clean Air Act requires a coal plant to go through federal Prevention of Significant Deterioration permitting, including a best available control technology analysis and air quality modeling, if a facility emits 100 tons of a criteria pollutant per year. Biomass plants get to emit two and a half times as much of each pollutant – 250 tons per year – before PSD permitting applies.

The fix: Burning biomass for electricity produces as much or more of key pollutants as coal – so biomass should be regulated like coal. EPA has the authority to require that biomass plants be added to the list of pollution sources where PSD permitting is triggered at 100 tons. Biomass power plants are big, polluting facilities that emit hundreds to thousands of tons of pollution each year. They should be regulated accordingly.

<u>Loophole 2: EPA's free pass for bioenergy CO_2 lets large power plants avoid regulation</u>
The EPA's decision to not regulate bioenergy CO_2 under the Clean Air Act was deemed unlawful by the U.S. Court of Appeals in 2013. The exemption has allowed a large number of plants to escape PSD permitting, thus doubling allowable pollution from this industry.

The fix: EPA should regulate bioenergy CO_2 now. Once in the PSD program, facilities can discuss how to reduce their net emissions of CO_2 during the consideration of best available control technology.

<u>Loophole 3: State regulators help biomass power plants avoid more protective permitting</u>
Regulators routinely accept even far-fetched permit limits for biomass facilities that claim they can meet "synthetic minor" permit limits of 250 tons of each criteria pollutant per year. Avoiding PSD doubles the pollution a plant is allowed to emit, and avoids air quality modeling that could determine whether a facility will cause EPA health standards to be exceeded.

The fix: If Loophole 1 were fixed, and PSD permitting was triggered at 100 tons of emissions, most biomass plants would have to go through PSD. Likewise, if EPA implemented the Court's decision and regulated bioenergy CO_2, most plants emit more than 100,000 tons of CO_2, also triggering PSD. Beyond those fixes, EPA should subject every power plant permit to federal oversight – especially those from states like Georgia, where regulators routinely issue synthetic minor source permits with the most minimal of conditions. It is going to take meaningful federal oversight to ensure these facilities set emissions limits that are federally enforceable, as the Clean Air Act requires.

Loophole 4: Most biomass plants have no restrictions on hazardous air emissions
The boiler rule, the part of the Clean Air Act that regulates emissions of hazardous air pollutants, is extremely weak. Area source plants, which constitute the majority of biomass facilities, have no limits on emissions of hazardous air pollutants, and the MACT standard for PM (0.03 lb/MMBtu) is double the rate issuing from most BACT determinations. Major source facilities face only lax emissions standards on PM, CO, HCl, and mercury, standards that usually don't require facilities to reduce their emissions at all.

The fix: EPA should make the so-called Maximum Available Control Technology standard meaningful, by setting standards as the Clean Air Act requires – standards that require the maximum degree of reduction of each HAP that is "achievable," considering cost and other statutory factors. At a minimum, without regard to cost, they must reflect the emission level that the cleanest sources have achieved – sources that are using emission control technologies that are effective and available, such as high-efficiency fabric filters that dramatically reduce particulate matter emissions. The biomass MACT should be made at least as protective as the standards for waste incinerators and coal boilers – especially given that facility can be classified as biomass boilers even when burning up to 90% coal, and when burning highly contaminated wastes.

Loophole 5: The biomass industry lowballs estimates of toxic emissions to avoid regulation
There is an epidemic of biomass facilities claiming to be synthetic minor sources for hazardous air pollutants. Almost no matter what their boiler size, facilities claim they should be regulated as area sources of HAPs that emit less than 25 tons of HAPs per year, and less than 10 tons of any individual HAP. Our analysis determined that the commonly used emission factor provided by the secretive industry group NCASI significantly under-represents typical emissions of hydrochloric acid, an important HAP. Using these industry emissions factors appears to lowball HAPs at the permitting stage, under-representing actual emissions.

The fix: EPA and the states should require that HAPs emissions are estimated at the permitting stage based on emissions factors that are transparently derived, with a generous margin for error that assumes emissions are likely to spike at the very times (such as startup and shutdown) when they are least likely to be measured. Most facilities are probably major sources for HAPs, and should be regulated as such.

Loophole 6: Weak testing requirements mean air toxics limits aren't enforceable
Facilities have been able to claim minor source status for HAPs with impunity because their permits contain so few requirements for actual testing and ongoing monitoring of emissions, once the plant is operating.

The fix: EPA's recent decision on the Hu Honua permit states that if a facility wants to be regulated as a synthetic minor source (for criteria pollutants or HAPs) it must conduct testing that represents its true emissions, including during startup and shutdown. The permit must be written to require such testing, otherwise it is not federally enforceable, and is thus invalid. For limits to be truly enforceable, there should be ongoing monitoring with results revealed in real time, so that states and citizens can know when and if a facility is violating its permit.

<u>Loophole 7: EPA rules blur the line between biomass facilities and incinerators</u>

EPA's rules allow materials that are just as contaminated as coal – and in some cases, more contaminated, as in the case of phthalate-containing "fuel cubes" – to be burned in biomass plants as "non-hazardous secondary materials," instead of waste incinerators, where emissions are more tightly regulated. EPA is proposing to grant a blanket designation as non-hazardous for construction and demolition waste wood, which contains heavy metals like arsenic, lead, and mercury, and emits carcinogens like benzene, formaldehyde, and dioxins when burned.

The fix: EPA needs to put people first – not the bioenergy industry, which has an inexhaustible appetite for contaminated fuels, particularly materials they are paid to dispose of by burning. The EPA should ensure that it does not create a loophole for unregulated waste incineration and that it protects public health by ensuring that all waste burners – including those that label themselves biomass units – meet the protective standards that Congress enacted for waste burning.

All around the country, communities are being faced with large biomass plants that are promoted as "clean and green" renewable energy. When people find out how much pollution these facilities emit, however, and the special treatment the bioenergy industry receives, they wonder why their scarce renewable energy dollars are supporting an industry that can, literally, kill people with its emissions. The data from the 88 permits we reviewed tells the story – again and again, biomass plants are allowed to emit more criteria pollutants and hazardous air pollutants, as well as greenhouse gases, than fossil fueled plants or even waste burners. The majority of the biomass plants currently being built will burn some kind of waste materials, and it is increasingly difficult for communities to protect themselves from toxic air pollution in light of the rollback on regulation at EPA now underway. It is time to take a clear-eyed look at what this bioenergy industry actually represents – the liquidation of pollution-emitting and often toxic materials into the atmosphere, where they are dispersed into the environment and the air we breathe. Across the board, it is time for states and the federal government to stop promoting and supporting biomass power as "clean" energy, and recognize its real impacts.

Summary case studies: the emerging bioenergy industry

The following are some representative examples of biomass power plants being proposed and built around the country. Information on facilities and the loopholes from which they benefit is taken from permits and permit application documents. Unlike the set of permits for new, "greenfield" facilities that we used for graphically demonstrating the differences between PSD facilities and synthetic minor facilities (Figures 4 through 7), this list includes some biomass facilities that previously burned fossil fuels.

Sierra Pacific, Anderson, CA

What: An existing facility that is increasing biomass-burning capacity. 468 MMBtu/hr stoker boiler; 31 MW (gross)

Estimated CO_2 emissions (tons per year): 401,890

Permitted emissions (tons per year): NOx: 267 CO: 472 $PM_{10\ total}$: 41 SO_2: no limit set

Status for NOx, PM, and CO: Major source (PSD)

Status for HAPs: Major source

Fuel: 25 bone dry tons/hour of: "a. Untreated wood pallets, crates, dunnage, untreated manufacturing and construction wood debris from urban areas; b. All agricultural crops or residues; c. Wood and wood wastes identified to follow all of the following practices; i. Harvested pursuant-to an approved timber management plan prepared in accordance with the Z'berg-Nejedly Forest practice Act of 1973 or other locally or nationally approved plan; ii. Harvested for the purpose of forest fire fuel reduction or forest stand improvement."

Construction and demolition wood or other waste allowed as fuel? Yes

Use of NCASI or other non-EPA factors to estimate HAPs? Unknown

Notes: This air permit does not set a limit for SO_2 at all, and does not specify any means of controlling emissions of HCl, as apparently, the major source limit of 0.022 lb/MMBtu for HCl under the boiler rule is so easily met, no controls are needed. The plant can emit up to 45 tons of HCl under the major source limit. This permit is also notable in that it actually specifies an emission rate for CO_2, unusual for a bioenergy plant permit.

DTE Stockton, Stockton, CA

What: Refire of old coal plant to biomass. 699 MMBtu/hr stoker boiler; 54 MW (gross).

Estimated CO_2 emissions (tons per year): 600,259

Permitted emissions (tons per year): NOx: 108 CO: 248 $PM_{10\ total}$: 58 SO_2: 70

Status for NOx, PM, and CO: Synthetic minor source (avoided PSD)

Status for HAPs: Synthetic minor source

Fuel: "Biomass is defined as any organic material originating from plants, not chemically treated and not derived from fossil fuels, including but not limited to products, by-products, and residues from agriculture, forestry, aquatic and related industries, such as agricultural, energy or feed crops and residues, orchard and vineyard prunings and removal, stone fruit pits, nut shells, cotton gin trash, corn stalks and stover, straw, seedhulls, sugarcane leavings and bagasse, aquatic plants and algae, cull logs, eucalyptus logs, poplars, willows, switchgrass, alfalfa, bark, lawn, yard and garden clippings, paper (unprinted), leaves, silvicultural residue, tree and brush pruning, sawdust, timber slash, mill scrap, wood and wood chips, and wood residue. Biomass does not include tires, material containing sewage sludge, or industrial, hazardous, radioactive, or municipal solid waste."

Construction and demolition wood or other waste allowed as fuel? Yes

Use of NCASI or other non-EPA factors to estimate HAPs? Yes

Notes: As a coal plant, this facility stopped operation in 2009. It is located in a highly polluted area, with "extreme" non-attainment status for ozone. Emissions from the new biomass boiler triggered offset requirements for emissions of NOx, SOx, PM_{10}, and VOCs, but rather than being compelled to obtain new offsets, the facility was allowed to treat the cessation of previous allowable emissions from the coal plant as mostly offsetting biopower emissions. Although the DTE Stockton boiler is about 50% larger than the boiler at the PSD-permitted Sierra Pacific Anderson plant described in this report, the DTE plant claimed synthetic minor status to avoid PSD permitting.

Plainfield Renewable Energy, Plainfield, CT

What: 523 MMBtu/hr fluidized bed boiler; 37.5 MW (net)

Estimated CO_2 emissions (tons per year): 449,207

Permitted emissions (tons per year): NOx: 175 CO: 239 $PM_{10\ fil}$: 84.8 SO_2: 81.3

Status for NOx, PM, and CO: Major source (PSD)

Status for HAPs: Synthetic minor source

Fuel: 56.54 tons per hour of chipped trees, stumps, branches or brush as defined in RCSA 22a-208a-1; Recycled wood or clean wood, meaning any wood or wood fuel which is derived from such products or processes as pallets skids, spools, packaging materials, bulky wood waste or scraps from newly built wood products, provided such wood is not treated wood. [CGS 22a-209a][RCSA 22a-208a-1]; Processed Construction and Demolition wood, meaning processed wood from construction and demolition activities which has been sorted to remove plastics, plaster, gypsum wallboard, asbestos, asphalt shingles and wood which contains creosote or to which pesticides have been applied or which contains substances defined as hazardous under section CGS 22a-115. [CGS 22a-209a]; Other types if properly sized, clean, uncontaminated wood materials, such as sawdust, chips, bark, tree trimmings or other similar materials. The plant is also allowed to burn up to 781 gal of biodiesel per hour, with no restrictions on number of hours that biodiesel can be burned.

Construction and demolition wood or other waste allowed as fuel? Yes

Use of NCASI or other non-EPA factors to estimate HAPs? Unknown

Notes: This permit requires the plant to burn "sorted" waste wood that has had contaminated materials removed, but does not specify what level of contamination is acceptable, a problem given that no sorting program can remove 100% of contaminated materials. The permit contains a requirement for *initial* testing for emissions of sulfuric acid, ammonia, arsenic, beryllium, cadmium, chromium, nickel, copper, benzene, titanium, formaldehyde, lead, manganese, mercury, dioxins (2,3,7,8-TCDD equivalents), selenium, hydrogen chloride, styrene, silver, and zinc. The permit also calls for the facility to meet certain emission limits for HAPs, but does not specify how those emission limits should be met, or whether testing for all HAPs is required. The HAPs provisions in this permit therefore appear to be unenforceable, although subsequent issuance of a Title V operating permit may rectify this.

Montville Power, Uncasville, CT

What: 600 MMBtu/hr stoker boiler when firing biomass; 42 MW (net). Can convert to distillate oil or gas for up to 995 MMBtu/hr and 82 MW (net).

Estimated CO_2 emissions (tons per year): 515,244 (when firing biomass)

Permitted emissions (tons per year): NOx: 158 CO: 263 $PM_{10\ fil}$: 31.5 SO_2: 65.7

Status for NOx, PM, and CO: Major source (PSD)

Status for HAPs: Presumably major

Fuel: Chipped trees, stumps, branches or brush. Recycled wood or clean wood, meaning any wood or wood fuel which is derived from such products or processes as pallets skids, spools, packaging materials, bulky wood waste or scraps from newly built wood products, provided such wood is not treated wood. Other Clean Wood, if properly sized, clean, uncontaminated wood materials, such as sawdust, chips, bark, tree trimmings or other organic based materials.

Construction and demolition wood or other waste allowed as fuel? Yes

Use of NCASI or other non-EPA factors to estimate HAPs? Unknown

Notes: This permit requires the facility to meet emissions standards for a long list of air toxics outlined in Connecticut regulations, but only specifies testing for HCl and ammonia, which while toxic, is not considered to be a hazardous air pollutant. The permit therefore appears to be unenforceable, although subsequent issuance of a Title V operating permit may rectify this.

Gainesville Renewable Energy, Gainesville, FL

What: 1,359 MMBtu/hr fluidized bed boiler; 116 MW (gross), 100 MW (net)

Estimated CO_2 emissions (tons per year): 1,167,000

Permitted emissions (tons per year): NOx: 416 CO: 714 $PM_{10\ fil}$: 58 SO_2: 172.6

Status for NOx, PM, and CO: Major source (PSD)

Status for HAPs: Initially permitted as area source; may be re-permitted as major source

Fuel: "Tops, limbs, whole tree material and other residues from soft and hardwoods that result from traditional silvicultural harvests; Saw dust, bark, shavings and kerf waste from cutting/milling whole green trees; fines from planning kiln-dried lumber; wood waste material generated by primary wood products industries such as round-offs, end cuts, sticks, pole ends; and reject lumber as well as residue material from the construction of wood trusses and pallets. Tops, limbs, whole tree material and other residues that result from the cutting or removal of certain, smaller trees from a stand to regulate the number, quality and distribution of the remaining commercial trees; and forest understory which includes smaller trees, bushes and saplings. Tops, limbs, whole tree material and other residues that are damaged due to storms, fires or infectious diseases. Tree parts and/or branches generated by landscaping contractors and power line/roadway clearance contractors that have been cut down for land development or right-ofway clearing purposes. Wood derived from used pallets packing crates; and dunnage disposed by commercial or industrial users. Herbaceous plant matter; clean agricultural residues (i.e., rice hulls, straw, etc.; no animal wastes or manure); and whole tree chips and pulpwood chips."

Construction and demolition wood or other waste allowed as fuel? No

Use of NCASI or other non-EPA factors to estimate HAPs? Yes

Notes: Early in the permit application process, this massive plant applied as a major source for HAPs, but subsequent revisions claimed it would emit less than 25 tons of HAPs, and the facility was ultimately permitted as an area source. Now, a pending and potential permit revision filed in February 2014 seeks to regulate the facility under the major source boiler rule,[153] after all, although this re-permitting process is currently suspended. If the plant is re-permitted as a major source for HAPs, its allowable filterable PM emissions will decrease under the major source MACT for bubbling fluidized bed boilers, from 0.015 lb/MMBtu to 0.0098 lb/MMBtu. This change would reduce permitted emissions of filterable PM from 89 tons to 58 tons per year.

Green Energy Partners, Lithonia, GA

What: Two stoker boilers of 93.22 MMBtu/hr; 11.5 MW (net).

Estimated CO_2 emissions (tons per year): 160,103

Permitted emissions (tons per year): NOx: 25 CO: 249 $PM_{10\ fil}$: 24 SO_2:8.1

Status for NOx, PM, and CO: Synthetic minor source (avoided PSD)

Status for HAPs: Synthetic minor source

Fuel: "Biomass shall consist of wood wastes in chip or in shredded form from timber harvesting, pre-commercial thinning of forest plantation stands, harvesting non-commercial, dead or deformed species for fuel purposes and land clearing activities (limbs, tops, stumps and non-commercial trees), and may also include peanut hulls, pecan shells, cotton stalks, lumber and pallet wood wastes (unpainted/untreated only) and similar woody biomass. "

Construction and demolition wood or other waste allowed as fuel? Yes

Use of NCASI or other non-EPA factors to estimate HAPs? Yes

Notes: This plant is being built in the Atlanta metro area, which is out of attainment with EPA's air quality standard for PM and ozone. It is proposing to use a ceramic filter system for control of NOx and PM, a technology unique to this facility. Permitted as a synthetic minor source, the company has avoided measures that could be taken to reduce emissions. Like almost all the biomass plants that have received air permits in Georgia in recent years, the

[153] Gainesville Renewable Energy Center. Initial Title V air operation permit application filed with Florida Department of Environmental Protection. February 10, 2014.

company was permitted to use non-EPA emissions factors for HAPs, which dramatically underestimate emissions compared to the EPA-sanctioned emissions factors.

North Star Jefferson, Wadley, GA

What: 312 MMBtu/hr fluidized bed boiler; 25 MW (gross).

Estimated CO_2 emissions (tons per year): 275,000

Permitted emissions (tons per year): NOx: 249 CO: 249 $PM_{10\ fil}$: 21 SO_2: 249

Status for NOx, PM, and CO: Synthetic minor source (avoided PSD)

Status for HAPs: Synthetic minor source

Fuel: wood, shredded tires

Construction and demolition wood or other waste allowed as fuel? Initially yes; as permitted, no.

Use of NCASI or other non-EPA factors to estimate HAPs? Yes

Notes: The facility is located in an area with large existing pollution sources, including wood-burners. No pre-construction air quality modeling has been conducted. It is being developed by a pro-forestry non-profit organization, the U.S. Endowment for Forestry and Communities, but the developer has stated that burning tires is important to the success of the facility. As for other biomass facilities permitted in Georgia, this facility used non-EPA sanctioned emissions factors to come to the conclusion that it is a minor source for HAPs. Initial stack tests are required to establish emissions rates for certain HAPs.

Piedmont Green Power, Barnesville, GA

What: 657 MMBtu/hr stoker boiler; 54.5 MW (net).

Estimated CO_2 emissions (tons per year): 564,192

Permitted emissions (tons per year): NOx: 228 CO: 227 $PM_{10\ fil}$: 86 SO_2: not spec

Status for NOx, PM, and CO: Synthetic minor source (avoided PSD)

Status for HAPs: Synthetic minor source

Fuel: "Biomass shall consist of wood wastes in chip or in shredded form from timber harvesting, pre-commercial thinning of forest plantation stands, harvesting non-commercial, dead or deformed species for fuel purposes and land clearing activities (limbs, tops, stumps and non-commercial trees), and may also include peanut hulls, pecan shells, cotton stalks, lumber and pallet wood wastes (unpainted/untreated only) and similar woody biomass."

Construction and demolition wood or other waste allowed as fuel? Yes

Use of NCASI or other non-EPA factors to estimate HAPs? Yes

Notes: While this facility claims to be a synthetic minor source for HAPs, and the permit states that potential emissions of HAPs are greater than 25 tons, the permit contains no testing requirements other than a one-time test for HCl. The permit would thus likely be deemed unenforceable under Clean Air Act requirements, although the omission might be rectified when the Title V operating permit is issued. This facility was awarded $49.5 million in "clean" energy funding from the federal government, as a 1603b award that converts the federal renewable energy incentive tax credit to a cash grant.

Hu Honua, Pepe'ekeo, HI

What: Refire of old coal plant. 407 MMBtu/hr stoker boiler; 23.8 MW gross, 21.5 MW net

Estimated CO_2 emissions (tons per year): 349,507

Permitted emissions (tons per year): NOx: 210 CO: 246 $PM_{10\ fil}$: 21.4 SO_2: 39.2

Status for NOx, PM, and CO: Synthetic minor source (avoided PSD)

Status for HAPs: Synthetic minor source

Fuel: wood, biodiesel

Construction and demolition wood or other waste allowed as fuel? No

Use of NCASI or other non-EPA factors to estimate HAPs? Yes

Notes: This facility took synthetic minor status for criteria pollutants and HAPs. EPA commented on this permit, observing that it was unlikely that a facility this size could stay below its CO cap, and observing that the use of non-EPA sanctioned emission factors for calculating HAPs emissions needed to be justified. As allowed by the Clean Air Act, a citizen group petitioned the EPA to formally object to the permit, and EPA has responded, agreeing that as written, the pollution limits are not enforceable. This decision is significant because EPA has made it clear that actual emissions testing for both criteria air pollutants and HAPs must be conducted under a variety of operating conditions for a facility to be able to claim and maintain synthetic minor source status. Many permits for bioenergy facilities being issued around the country do not contain these requirements, particularly for HAPs, and are therefore likely unenforceable under the terms of the Clean Air Act.

ecoPower, Hazard, KY

What: 745 MMBtu/hr fluidized bed boiler; 58 MW

Estimated CO_2 emissions (tons per year): 577,073

Permitted emissions (tons per year): NOx: 240 CO: 240 $PM_{10\ fil}$: 240 SO_2: 240

Status for NOx, PM, and CO: Synthetic minor source (avoided PSD)

Status for HAPs: Synthetic minor source

Fuel: Hardwood tree stems removed during pre-commercial thinning operations. Storm and fire damaged hardwood trees and tree parts. Low quality hardwood logs and hardwood blocks that are trimmed in the production of sawlogs. Hardwood wood industry byproducts such as shavings, saw dust, bark, and similar materials that do not contain preservatives, resins, or other additives. Low quality hardwood logs and hardwood wood chips produced during right-of-way operations and urban forestry operations. Unrecyclable untreated hardwood pallets, untreated lumber, and dunnage.

Construction and demolition wood or other waste allowed as fuel? Yes

Use of NCASI or other non-EPA factors to estimate HAPs? Yes

Notes: An early draft of the air permit classified the facility as a major source for HAPs that would emit over 35 tons per year. The final version of the permit reduced the amount of HAPs to 7.71 tons. The applicant achieved the reduction in estimated HAPs by making up their own HAPs emissions factors, and only counting certain HAPs toward total emissions. Provisions requiring stack testing were removed in the final version of the permit, so the HAPs limits are unenforceable at this point.

Verso Bucksport, Bucksport, ME

What: 814 MMBtu/hr stoker boiler; 25 MW (gross)

Estimated CO_2 emissions (tons per year): 699,014

Permitted emissions (tons per year): NOx: 476.3 CO: 952.7 $PM_{10\ fil}$: 95.3 SO_2: 243.9

Status for NOx, PM, and CO: Major source

Status for HAPs: Presumably a major source; permit makes no mention of HAPs.

Fuel: "Fuel oil (including fuel oil, off-specification waste oil, and specification waste oil), natural gas, and biomass (including wood waste, wood chips, bark, mill waste treatment sludge, paper roll core ends, and waste papers)."

Construction and demolition wood or other waste allowed as fuel? Yes

Use of NCASI or other non-EPA factors to estimate HAPs? Unknown

Notes: Located immediately adjacent to homes and schools, the Verso Bucksport paper mill expanded its biomass-burning capabilities to 25 MW to take advantage of renewable energy credits available in the Northeast. Although the facility went through a BACT analysis, its emission rate for PM (at 0.03 lb/MMBtu) is highly permissive, double what other BACT-permitted plants and coal plants achieve. At 0.3 lb/MMBtu, the 24-hr allowable NOx emissions rate is also more than triple the limit at other PSD- permitted plants. The facility does not use any sorbent system to reduce hydrochloric acid emissions.

Burgess Biopower, Berlin, NH

What: 1,013 MMBtu/hr bubbling fluidized bed boiler; 70 MW (gross)

Estimated CO_2 emissions (tons per year): 869,903

Permitted emissions (tons per year): NOx: 244.5 CO: 307.3 $PM_{10\ fil}$: 40.9 SO_2: 48.7

Status for NOx, PM, and CO: Major source

Status for HAPs: Major source

Fuel: "Whole tree wood chips and other low-grade clean wood"

Construction and demolition wood or other waste allowed as fuel? No

Use of NCASI or other non-EPA factors to estimate HAPs? Unknown

Notes: Located at the site of an old pulp mill, this facility is immediately adjacent to homes and schools. It is the largest wood-burning plant in the Northeast. The permit specifies that the plant will burn about 113 tons of wood chips per hour, which will be sourced primarily from whole trees. This facility admitted to being a major source for HAPs, in contrast to another all "clean" wood plant, the 100 MW (net) Gainesville Renewable Energy Center, which claimed to be an area source.

ReEnergy Lyonsdale Biomass, Lyons Falls, NY

What: 290 MMBtu/hr stoker boiler; 19 MW (net)

Estimated CO_2 emissions (tons per year): 243,882

Permitted emissions (tons per year): NOx: 249 CO: 249 $PM_{10\ fil}$: ~124 SO_2: "Less than 10 tons"

Status for NOx, PM, and CO: Synthetic minor source (avoided PSD)

Status for HAPs: Synthetic minor source

Fuel: Unadulterated wood, up to 30% pallets; also non-recyclable fibrous material such as wax cardboard in combination with other fuels in quantities up to and equal to 30% by weight of the boiler's fuel feed. Non-recyclable fibrous material may be in the form of pellets, extrusions, chips, shreds, or other shapes that provide suitable fuel management capability.

Construction and demolition wood or other waste allowed as fuel? Yes

Use of NCASI or other non-EPA factors to estimate HAPs? Unknown

Notes: While the permit clearly authorizes the facility to burn waste materials, the company's website states that the plant "*provides sustainable electricity from responsibly harvested green forest residue biomass, and unadulterated wood.* This permit exploits an obscure loophole in the law that allows it to specify a filterable particulate matter emission rate of 0.1 lb/MMBtu. The facility is required to do one stack test for PM every five years to demonstrate compliance. The permitted NOx emission rate of 0.2 lb/MMBtu is about three times higher than the rate at plants that go through a BACT analysis. The permit contains no limits on HCl emissions and no sorbent system is specified in the permit. This is a Title V permit with no firm testing requirements to establish and maintain its synthetic minor source status for HAPs, suggesting that it is unenforceable.

ReEnergy Black River, Fort Drum, NY

What: Refire of existing old coal plant. Three circulating fluidized bed boilers, 284 MMBtu/hr each; 60 MW (gross)

Estimated CO_2 emissions (tons per year): 658,274

Permitted emissions (tons per year): NOx: 538.5 CO:234.1 $PM_{10\ fil}$: 52 SO_2: 696.3

Status for NOx, PM, and CO: Major source

Status for HAPs: Synthetic minor source

Fuel: "The proposed fuels to be combusted are clean wood, unadulterated wood from C+D debris, glued wood creosote treated wood, tire derived fuel and non-recyclable fibrous material (waste paper)."

Construction and demolition wood or other waste allowed as fuel? Yes

Use of NCASI or other non-EPA factors to estimate HAPs? Unknown

Notes: This facility is allowed to burn a number of waste-derived fuels. Its testing requirements for fuel state "*ReEnergy shall employ the "grid test" which consists of a 10 by 10 grid placed over the wood stream and checked to determine the percentage of glued wood, treated/painted wood, and non-wood materials. If it is determined that the percentage of glued wood is between 0 and 1.0% by volume, then the percentage of glued wood for that load is 1%. If it is determined that the percentage of glued wood is between 1% and 20% by volume, the percentage of glued wood for that load is 20%. If it is determined that the percentage of glued wood is greater than 20% by volume, then the load is considered to 100% glued wood. This method shall be employed once every 5 loads per supplier."* This is a Title V permit with no firm testing requirements to establish and maintain its synthetic minor source status for HAPs, suggesting that it is unenforceable.

Biogreen Sustainable Energy, La Pine, OR

What: 353 MMBtu stoker boiler, 24.9 MW (net)
Estimated CO_2 emissions (tons per year): 303,135
Permitted emissions (tons per year): NOx: 232 CO:247 $PM_{10\ fil}$: 46 SO_2: 39
Status for NOx, PM, and CO: Synthetic minor source (avoided PSD)
Status for HAPs: Synthetic minor source
Fuel: "Wood in the form of hog fuel, bark, and chips, forest management residue (slash), wood from yard debris , and construction and demolition wood materials will be used as fuel for the boiler. The facility will not bum wood by-products that contain plywood or resin materials. Less than 20% of the heat input to the boiler on an annual basis will come from yard debris and construction and demolition materials"
Construction and demolition wood or other waste allowed as fuel? Yes
Use of NCASI or other non-EPA factors to estimate HAPs? Yes
Notes: The facility's website[154] states, "Creating clean energy from local forests," but a significant portion of the plant's fuel will come from construction and demolition waste. This permit contains a requirement to test HCl emissions to ensure its emission factor is valid, but does not contain any requirement to test for other HAPs, suggesting it is unenforceable.

Evergreen Community Power/United Corrstack, Reading, PA

What: 482 MMBtu/hr stoker boiler; 33 MW (gross)
Estimated CO_2 emissions (tons per year): 414,000
Permitted emissions (tons per year): NOx: 96 CO: 99 $PM_{10\ fil}$: 96 SO_2: 92
Status for NOx, PM, and CO: Synthetic minor source (avoided PSD)
Status for HAPs: Synthetic minor source
Fuel: Wood, construction waste, municipal waste
Construction and demolition wood or other waste allowed as fuel? Yes
Use of NCASI or other non-EPA factors to estimate HAPs? Yes
Notes: See section above for details on this plant.

Nacogdoches Power, Sacul, TX

What: 1,374 MMBtu bubbling fluidized bed boiler, 116 MW (gross).
Estimated CO_2 emissions (tons per year): 1,179,908
Permitted emissions[155] (tons per year): NOx: 602 CO: 903 $PM_{10\ total}$: 192.6 SO_2: 274
Status for NOx, PM, and CO: Major source (PSD)
Status for HAPs: Major source
Fuel: 1.4 million tons a year of "biomass materials in the form of forest residue (primarily residual tops and limbs of trees, unutilized cull trees, and slash), and mill residue (including sawdust). Whole tree wood chips may also be used as fuel."

[154] http://biogreenenergyco.com/
[155] Calculated from permitted rates, as no limits for total tons are specified in permit.

Construction and demolition wood or other waste allowed as fuel? Yes – “clean municipal wood waste”
Use of NCASI or other non-EPA factors to estimate HAPs? Unknown
Notes: This is the sister plant to the Gainesville Renewable Energy Center in Florida, which claims to be a minor source for HAPs although it was permitted as a major source. The Nacogdoches plant was permitted as a major source, with permitted emissions of 126 tons of HCl per year.

EDF Allendale, Allendale, SC

What: New facility; 275 MMBtu/hr stoker; 21 MW gross, 17.5 MW net
Estimated CO_2 emissions (tons per year): 236,153
Permitted emissions (tons per year): NOx: 241 CO: 250 $PM_{10\,fil}$: 36 SO_2: 30.1
Status for NOx, PM, and CO: Synthetic minor source (avoided PSD)
Status for HAPs: Synthetic minor source
Fuel: The boiler is permitted to burn only clean, untreated wood waste as fuel. Clean wood is defined in SC Regulation 61-62.1 as untreated wood or untreated wood products including clean untreated lumber, tree stumps (whole or chipped), and tree limbs (whole or chipped). Clean wood does not include yard waste, or construction, renovation, and demolition waste (including but not limited to railroad ties and telephone poles). The use of any other substances, including yard waste and construction, renovation and demolition waste, as fuel is prohibited without prior issuance of a construction permit revision from the Bureau of Air Quality.
Construction and demolition wood or other waste allowed as fuel? No
Use of NCASI or other non-EPA factors to estimate HAPs? Yes
Notes: This permit would be a major source for HAPs if AP-42 emission factors had been used to calculate emissions instead of a combination of NCASI and other factors. This facility has a twin which has also recently come online, the EDF Dorchester plant in Harleyville, SC.

Dominion Energy, Southampton, Altavista, and Hopewell, VA

What: Three 63-MW coal plants being converted to 51 MW biomass plants: Altavista (Altavista, VA), Hopewell (Hopewell, VA) and Southampton (Franklin, VA)
Estimated CO_2 emissions (tons per year): 2,030,060 (three facilities)
Permitted emissions (tons per year): NOx: 412 (x 3) = 1,236 CO: 916 (x 3) = 2,748
$PM_{10\,fil}$: 59.6(x 3) = 178.7 SO_2: 38.2 (x 3) = 114.6
Status for NOx, PM, and CO: Major sources (PSD)
Status for HAPs: Unknown.
Fuel: Three permits; two specify use of 785,480 tons of wood a year and no contaminated wood; one permit (Southampton) allows use of 5,879,518 gal/yr distillate fuel oil. “Biomass means those residuals that are akin to traditional cellulosic biomass including forest-derived biomass (e.g., green wood, forest thinnings, clean and unadulterated bark, sawdust, trim, and tree harvesting residuals from logging and sawmill materials) wood collected from forest fire clearance activities, trees and clean wood found in disaster debris, and clean

biomass from land clearing operations, each as specified in the definition of Clean Cellulosic Biomass in 40 CFR 241.2, excluding any wood which contains chemical treatments or has affixed thereto paint and/or finishing materials or paper or plastic laminates. Approved biomass is biomass that does not contain contaminants at concentrations not normally associated with virgin biomass materials."

Construction and demolition wood or other waste allowed as fuel? No

Use of NCASI or other non-EPA factors to estimate HAPs? Yes

Notes: While initial stack testing is required to determine emissions of SO_2, NOx, CO, VOCs, sulfuric acid mist, and hydrogen fluoride, there is no stack testing required for HCl or other HAPs. Requirements for HAPs testing may be included when Title V operating permits for the plants are issued.

Nippon Paper, Port Angeles, WA

What: Facility expansion; 420 MMBtu/hr stoker; ~20 MW net (cogen, uses some thermal energy)

Estimated CO_2 emissions (tons per year): 360,670

Permitted emissions (tons per year): NOx: 184 CO: 644 $PM_{10\text{ fil}}$: 2 SO_2: 152

Status for NOx, PM, and CO: Major source

Status for HAPs: Major source (PSD)

Fuel: "Approved Cogeneration Plant Fuels: The Permittee shall burn only clean woody biomass, recycled wood-derived fuel, dewatered wastewater treatment sludge, natural gas, and ultra low sulfur diesel fuel in the cogeneration plant. For the purpose of this order: a. Clean woody biomass, also known as hog fuel or hogged fuel, is defined is any woody material that meets the definition of clean cellulosic biomass in §241.2. b. Recycled wood-derived fuel is defined as any woody, non-hazardous secondary material that has been declared non-waste by the standards and procedures outlined in §241.3. c. Dewatered wastewater treatment sludge is defined as clarifier sludge consisting largely of pulp and paper fibers and produced on site that has been declared non-waste by the standards and procedures outlined in §241.3. d. Natural gas means any fuel defined as natural gas in §63.7575, including propane and LPG. e. Ultra low sulfur diesel fuel means fuel oils containing less than 0.05 weight percent nitrogen and less than 0.0015 weight percent sulfur that comply with the specifications for fuel oils numbers 1 and 2 as defined by ASTM D396 or diesel fuel numbers 1 and 2 as defined by ASTM D975. Ultra low sulfur fuel oil may contain any percentage of biodiesel that complies with the specifications in ASTM 6751, provided the nitrogen and sulfur limits are met by the liquid fuel mixture."

Construction and demolition wood or other waste allowed as fuel? Yes

Use of NCASI or other non-EPA factors to estimate HAPs? Yes

Notes: Located on the Olympic Peninsula, about 31 miles from the Port Townsend Paper Company, this facility was required to reduce emissions of air toxics more than most other facilities we reviewed, but as it burns a variety of contaminated fuels, including paper-making sludge, its emissions of air toxics are likely to be high. The company is required by its permit to develop a fuel monitoring plan and test fuel analyze for chlorine and mercury content. It is supposed to ensure that "recycled wood derived fuel" meets a quality assurance plan. The plant was permitted as a major source of HAPs before the significantly weakened version of the boiler rule that exists today, and was required to meet a filterable PM emission limit of 0.0011 lb/MMBtu (the current MACT standard for major source boilers is 0.03 lb/MMBtu, which is 27 times higher). The filterable PM limit explains the relatively low estimated emissions of 2 tons per year from the plant. The permit also sets limits for emissions of acrolein, ammonia, benzene, formaldehyde, hydrogen chloride (HCl) mercury, and dioxins/furans. Initial and "intermittent" stack tests are required to ensure compliance (once per permit term, or every five years). The plant is also required to install a continuous emissions monitoring system for PM, which is unusual for the permits we reviewed.

Port Townsend Paper Company, Port Townsend, WA

What: Facility expansion; 414 MMBtu/hr stoker; ~24 MW net (cogen, uses some thermal energy)
Estimated CO_2 emissions (tons per year): 355,518
Permitted emissions (tons per year): NOx: 262 CO: 635 $PM_{10\ fil}$: 36.4 SO_2: 96
Status for NOx, PM, and CO: Major source (PSD)
Status for HAPs: Synthetic minor source
Fuel: "Wood fuels including hog fuel, forest biomass, and urban wood. Ecology does not currently classify these wood fuels as solid waste. Wood fuels do not include wood treated with creosote, pentachlorophenol, or copper-chrome-arsenic; or municipal waste. Forest biomass means the by-products of current forest management activities, current forest protection treatments authorized by the agency, or the by-products of forest health treatment prescribed or permitted under Washington's forest health law. Forest biomass does not include municipal solid waste. Urban wood is purchased wood fuel meeting an acceptance program which prohibits wood treated with creosote, pentachlorophenol, or copper-chrome-arsenic; municipal waste, hazardous material contaminants (asbestos, lead, mercury), lead painted items, and plastic coatings." (Urban wood is demolition waste. Port Townsend Paper's fuel also includes reprocessed fuel oil (about 15% of total fuel) and corrugated cardboard recycling rejects ("OCC rejects"), meaning corrugated boxes that are too contaminated with labels, fasteners, etc., to recycle. PTPC uses approximately one-third of Washington's recycled cardboard.
Construction and demolition wood or other waste allowed as fuel? Yes
Use of NCASI or other non-EPA factors to estimate HAPs? Yes
Notes: Unlike the Nippon Paper plant at Port Angeles, which was issued by the Olympic Region Clean Air Agency in Washington, the permit for this facility was issued by the Washington Department of Ecology and contains relatively few protective measures, even though it is a larger facility than the Nippon plant. Emissions calculations that were used to justify the expansion of biomass burning at the facility include reductions from installing future emissions control equipment that will be required by law regardless of whether the biomass project is built or not. The proposed expansion will increase fuel throughput to 2.9 times the present amounts.

Attachment B

New Hampshire Department of Environmental Services
Air Resources Division
P.O. Box 95, 29 Hazen Drive
Concord, NH 03302-0095
Phone: 603-271-1370 Fax: 603-271-7053

PERMIT APPLICATION REVIEW SUMMARY

Facility:	DG Whitefield LLC			**Engineer:**	Barbara Georgitsis	
Location:	260 Airport Road, Whitefield, NH 03598					
AFS #:	3300700010	**Application #:**	17-0004	**Date:**	1/22/2018	

DATE APPLICATION RECEIVED

Title V Operating Permit renewal application #17-0004 was received timely on January 6, 2017, and therefore, the facility is operating under an application shield.

PROJECT DESCRIPTION

The purpose of this permit action is the renewal of the facility's Title V Operating Permit TV-0007 which expired on July 31, 2017.

CHANGES FROM THE PREVIOUS PERMIT

- The parent corporation has changed and is now EWP Renewable Corporation of Mount Laurel, NJ as of September 30, 2010. The Responsible Official remains at DG Whitefield LLC per ARD-1 form.
- Updates to current Title V template permit language.
- Removed state-only opacity exemptions (Table 5, Items 10, 11 and 13 of the previous permit) since they are less stringent than USEPA's.
- Addition of footnote to Table 3 PCE3: "Installed by the facility to control NOx and to optionally control CO. The device was once a Regenerative SCR using two duct burners for NOx control under the "fired" mode. The facility has been able to operate the device without the duct burners and continue to meet permit limits and requirements. The duct burners have been removed and the RSCR operates as a traditional SCR system for controlling NOx emissions and CO.
- The one-time energy assessment pursuant to 40 CFR 63 Subpart JJJJJJ was performed for the boiler, EU01, in January 2014 in conjunction with the tune-up. It was reviewed and accepted by the department; therefore, this item in Table 6, Item 21 was removed.
- The boiler, EU01, has an oxygen trim system and requires tune-ups every 5 years and not biennially so this condition was changed in Table 6, Item 20.
- Updated SO_2 to 0.5% sulfur by weight from 0.4% by weight for diesel fuel due to the fact that diesel is not a regulated fuel under Env-A 1600, and the updated limit is based on the ASTM standards. The facility's emergency engine & fire pump engine is not subject to 40 CFR 63, Subpart IIII or 40 CFR 63, Subpart ZZZZ fuel restrictions on sulfur content in diesel since they are emergency and below 500 hp. Therefore, the emission factor was changed (1.01* %S) and the SO_2 potential and permitted emissions were recalculated.

FACILITY DESCRIPTION

DG Whitefield LLC (the facility) owns and operates an 18.8 MW gross output power generation facility located in Whitefield, New Hampshire. The primary sources of emissions at the facility are a wood-fired boiler, an emergency generator diesel engine, a fire pump diesel engine and a cooling tower. The facility is a major source of NOx and CO and therefore requires a Title V Operating Permit.

Air pollution control at the facility includes a NOx reduction system, a combustion control system and a CO catalyst to minimize CO emissions, and monitors to continuously record CO, CO2, NOx, opacity and certain operational parameters. The following emission units are covered by the permit:

Table 1 – Significant Activities

Emission Unit #	Description of Emission Unit	Install Date	Emission Unit Maximum Design Capacity
EU01	Babcock and Wilcox Wood-fired Boiler Model No: Towerpak CCZ Serial No. 757801	1987	Maximum Firing Rate: 1. 220 MMBTU/hr for wood equivalent to: a. 185,000 lb/hr of steam averaged over 24-hour period at 900° F and 920 psig; and b. 252,000 tpy for wood chips at 55% moisture
EU02	Cummins Diesel Emergency Generator Engine Model # NTTA855G2 Serial No. P 3711/2	1987	1. Maximum Firing Rate-3.5 MMBTU/hr 2. Rated Output-470 HP
EU03	Cummins Diesel Fire Pump Engine Model # V-5-4-F2 Serial No. 20245711	1987	1. Maximum Firing Rate-2.4 MMBTU/hr 2. Rated output-187 HP
EU04	Lillie-Hoffman Cooling Towers, Inc. Model # S14M-2432-3-22 Serial No. N/A 3-Cell Cooling Tower	1987	1. Drift Factor= 0.00088 % 2. Circulation Rate=11,473 gpm

PERMIT HISTORY

1. On January 11, 1999, Title V Permit TV-OP-007 was issued to Thermo Ecotek Corporation for Whitefield Power and Light facility for the following devices:
    a. Wood-fired Boiler; and
    b. Emergency diesel generator.
2. On November 15, 1999, the Title V permit was amended to correct typographical errors in the designation of authority for conditions 6, 7, and 8 in Sec. VIII.C. The three conditions (Env-A 2003.04, 2003.04(e)(2) and 2003.04(f)) were moved to State-Only Section.
3. On April 12, 2000, the Title V permit was amended to correct typographical errors in the numbering scheme on pg 11, Sec. VIII.C. and the General Title V Operating Conditions.
4. On June 26, 2001, the Title V permit was amended to reflect the change in the name of the owner/operator and technical contact on pg. 1.
5. On November 15, 2001, the Title V permit was amended to reflect the change in the parent company from Thermo Ecotek Corporation to AES Ecotec Holdings LLC.
6. On September 10, 2004 a Temporary Permit, TP-B-0500, was issued for a Regenerative Selective Catalytic Reduction System (RSCR) for NOx control for wood-fired Boiler.
7. On June 6, 2005 a minor modification was done to TP-B-0500 for the installation of CO catalyst in the RSCR.
8. Title V operating Permit TV-OP-007 was issued on September 30, 2005.
9. On July 23, 2007, a minor modification was done to TV-OP-007 to include an alternative operating scenario for RSCR. The facility requested to operate RSCR in two temperature modes, high and low.
10. Temporary Permit TP-B-0547 issued on June 2, 2008. TP-B-0547 authorized the permittee to make physical modifications to the wood-fired boiler that increased the amount of steam provided to the steam turbine generator, which increased the power output of the facility from 16 MWe to approximately 18 MWe gross output. The boiler's steam generating capacity was increased from 160,000 pounds per hour (lb/hr) to 170,000 lb/hr. To avoid the requirements of New Source Review (NSR), the facility accepted a new NOx limit of 111.12 tons per consecutive 12-month period for the wood-fired boiler.

11. Minor modifications were made to the Title V permit on November 10, 2009, including a correction in the steam flow to 180,000 lb/hr.

12. Title V Operating Permit, TV-0007, renewal was issued on July 20, 2012, and the application number is 10-0038 which includes a request for a higher steam flow from 180,000 lb/hr to 185,000 lb/hr which was approved and is in the permit.

LIST OF INSIGNIFICANT ACTIVITIES – emissions are less than 1000 lbs/yr and not subject to any permit requirements (Env-A 609.04). The facility submitted worksheets using EPA Tanks' software to quantify emissions and the parts washer is insignificant. Following are the insignificant activities[1]:

ID	Unit	General Description/Comments
1.	Waste Oil Furnace - installed 1997	Below the applicability threshold (see Recycled Oil Burners letter): Heat Input-0.14 mmBtu/hr Fuel Flow Rate-1.0 gal/hr Fuel Consumption-1,000 gal/yr Exhaust stack - 8" diameter, 25'above ground level, vertical discharge
2.	Parts Washer – installed 2000	1 fluid change annually at 20 gallons per change
3.	Emerg. generator diesel storage tank - 1987	200 gals low sulfur diesel – 1 fill annually
4.	Fire Pump diesel storage tank – 1987	250 gals low sulfur diesel – 3 fills annually
5.	Waste oil storage tank – 1995	1000 gals used machinery oil
6.	Waste oil furnace storage tank - 1997	340 gals used machinery oil
7.	Waste oil storage tank – 1998	300 gals used machinery oil
8.	Bulk diesel fuel storage tank – 2004[2]	12,000 gals low sulfur diesel – for fuel needs of the front-end loaders that deliver wood fuel
9.	Spare parts building heater fuel tank - 1995	275 gals low sulfur diesel – 2 fills annually
10.	Portable fuel tank – 1997	150 gals low sulfur diesel

POLLUTION CONTROL EQUIPMENT

Pollution Control Equipment #	Description of Equipment	Activity	Emission Unit #
PCE01	Multicyclone (Multiclone)	Primary particulate matter control	EU01
PCE02	Electrostatic Precipitator (ESP)	Secondary particulate matter control	EU01
PCE03	Selective Catalytic Reduction System (SCR) with NOx and CO catalysts	NOx and CO control	EU01

[1] Emissions from the insignificant activities shall not be included in the total facility emissions for the annual emission-based fee calculation (update to Env-A 609.04). They will be reviewed at every five year renewal.
[2] This diesel fuel storage tank was originally used to provide fuel to the RSCR burners, but the RSCR was modified to an SCR and the burners dismantled.

EMISSION CALCULATIONS

Boiler (EU01)

Pollutant	Emission Factor or Regulatory Limit	Basis	Emission Rates	
	lb/MMBtu		Lb/hr	tons/yr
TSP/PM_{10}	0.32	AP-42, Chapter 1.6	70.4	308.35
	0.10	NSPS Subpart Db	22.0	96.36
	0.043	**Stack test (6/15/16-Avg TSP) x 1.1**[b]	**9.44**	**41.34**
SO_2	.025	AP-42, Chapter 1.6[c]	5.5	24.1
	.001	**Stack test (Sept 2009)**[a] **x 1.1**[b]	**0.22**	**0.96**
NOx	0.22	AP-42, Chapter 1.6[c]	48.4	212
	-	PSD avoidance	57	< 250
	-	permit limit[d]	25.3	< 111.12
	0.064	**Stack test (6/15/16) x 1.1**[b]	**14.08**	**61.67**
CO	**.112**	**Stack test (6/15/16) x 1.1**[b]	**24.64**	**107.92**
	-	Permit Limit (TP-B-0500)	57	< 250
VOC	**0.0045**	**Stack test (6/15/16) x 1.1**[b]	**0.99**	**4.34**
Ammonia (RTAP)	20 ppmdv@6%O2	Permit limit (TP-B-0500)	2.52	11.04
	3.26 ppmdv@6%O2	**Stack test (6/15/16 is .0019 lb/MMBtu) x 1.1**[b]	**0.46**	**2.01**
HCl (HAP)	**0.00011**	**2004 Compliance Test**	**0.0242**	**0.11**

a – Stack test results from the facility performed on 6/15/16. Tested emission rates (PM, VOC, Ammonia, CO) **all passed** the permit limits for the respective pollutant).

b - Stack test results in lb/MMBtu and lb/hr adjusted by a factor of 1.1 (ten percent margin) to account for normal variation in results; lb/hr values are measured/actual data and associated annual emissions in tons/yr assume 8760 hours of operation; data are in **bold** above.

c – USEPA AP-42, Section 1.6 Wood Residue Combustion in Boilers (3/02)

d - Permit limit for attainment area (Coos County) New Source Review avoidance in the Ozone Transport Region (OTR)

e - Ammonia emission rate = from 6/15/16 RATA (CEM stack test) using the most conservative run out of three samples.

f - HCl emissions were reported at the detection limit during the 2004 compliance test. The emission factor listed above includes a 10% safety factor of the reported emissions. The reported HCL emissions (at the detection limit) were 0.5% of the AP-42 emission factor.

Emergency Engines (EU02 & EU03)

The emergency engine (EU02) and fire pump (EU03) engine are limited to 500 hours per year of operation to qualify as emergency generators as defined under Env-A 101.671. Maximum annual permitted emissions for the noted number of operating hours were developed using EPA's AP-42 emission factors [Chapter 3.3 Gasoline and Diesel Industrial Engines (updated 10/96)] and the NOx factor from the department (DES) memo dated April 1996:

Emergency Generator (EU02)

	Emission Factor	Emission Rate	Maximum Permitted Emission Rate
Pollutant	**lb/MMBtu**	**lb/hr**	**tons/yr**
TSP/PM_{10}	0.31	1.09	0.27
SO_2	0.29	1.02	0.25
NOx	3.56	12.46	3.12
CO	0.95	3.33	0.83
VOC	0.35	1.23	0.31

Fire Pump (EU03)

	Emission Factor	Emission Rate	Maximum Permitted Emission Rate
Pollutant	**lb/MMBtu**	**lb/hr**	**tons/yr**
TSP/PM_{10}	0.31	0.74	0.19
SO_2	0.29	0.70	0.17
NOx	3.56	8.54	2.14
CO	0.95	2.28	0.57
VOC	0.35	0.84	0.21

Combined Emergency Engine (EU02) and Fire Pump Engine (EU03)

	Fire Pump	Emergency Generator	Engines Total
Pollutant	**tpy**	**tpy**	**tpy**
TSP/PM_{10}	0.19	0.27	**0.46**
SO_2	0.17	0.25	**0.42**
NOx	2.14	3.12	**5.25**
CO	0.57	0.83	**1.40**
VOC	0.21	0.31	**0.52**

Cooling Tower (EU04)

Steam that has passed through the steam turbine is cooled by water in the condenser. The cooling water is then circulated through the cooling tower to release thermal energy to the ambient air before being cycled back through the condenser. Cooling tower drift is limited to 0.00088% of the circulating water flow rate.

Cooling Tower Emissions:

Particulate Emissions

Conductivity=20,000 micro-ohms
Circulation rate=11,473 gpm
Total liquid drift=0.00088% or 0.073 lb drift/kgal

(Eq 1) Conductivity x 2/3 is essentially TDS in ppm

20,000 micro-ohms * 2/3 =13.333 ppm TDS = 0.013 fraction of TDS in water

(Eq 2) Annual Drift= Circulation rate* Drift factor =

11,473 gpm*60 min/hr*8760 hrs/yr* 7.3×10^{-5} lb drift/gal = 440,190 lb drift/yr

(Eq 3) TSP emissions =Annual Drift * TDS =

440,190 lb drift/yr * 0.013 = 5722.47 lb/yr = 2.86 tpy

Facility-wide Emissions

Pollutant	Boiler (EU01)	Boiler (EU01)	Emergency Generator (EU02)	Fire Pump Engine (EU03)	Cooling Tower (EU04)	Facility-wide Emissions	Permit Limits	Permit Limits
	lb/hr	tpy	tpy	tpy	tpy	tpy	lb/hr	tpy
TSP	9.438	41.34	0.27	0.19	2.86	44.66	--	--
PM_{10}	9.438	41.34	0.27	0.19	2.86	44.66		--
SO_2	0.22	0.96	0.25	0.17	--	1.39	--	--
NO_x	14.08	61.7	3.12	2.14	--	66.95	< 25.3	< 111.12
CO	24.64	107.90	0.83	0.57	--	109.30	< 57	< 250
Non-MethaneVOCs	0.99	4.30	0.31	0.21	--	4.82	--	--

HAPs

HCl emissions were reported at the detection limit during the 2004 compliance test. See EU01, wood fired boiler, emission's table above.

RTAPs - Env-A 1400

1. As a result of the use of ammonia in SCR system (PCE03), ammonia which does not completely react with the NO_x during the reaction process is emitted to the air (called ammonia slip). Adjusted in-stack concentration method was used to show compliance with Env-A 1400. Ammonia was tested at the facility in 6/2016 and 6/2017 and passed both compliance tests for ammonia drift.

2. Small quantities of sulfuric acid (drift loss) are emitted from the cooling tower (due to the usage of additives in the cooling tower). Emissions are below the de minimis levels specified in Env-A 1400. Additives used have changed since the previous permit and no longer include sodium hydroxide. Small quantities of potassium hydroxide (drift loss) are emitted from the cooling tower and are below the annual deminimis emission level. See table below:

CAS #	Compound	Emissions lb/day	Emissions lb/yr	24-hr Deminimus lb/day	Annual Deminimus lb/yr
7664-93-9	Sulfuric Acid	2.8×10^{-4}	0.100	0.0084	3.1
1310-58-3	Potassium Hydroxide	3.15×10^{-5}	0.011	0.13	48

Reference – the Env-A 1400, RTAP, review received by the department February 21, 2017.

MODELING

The facility is in compliance with NAAQS based on modeling conducted in 1993. The cooling tower is in compliance with Env-A 1400 (see Env-A-1400 entry under State Regulations below). Boiler stack in compliance with Env-A-1400 for ammonia based on 20 ppm slip using RATA test results.

COMPLIANCE STATUS

Emission Testing – RATA stack testing is required for the wood-fired boiler-EU01, for particulate matter (once every 5 years) and Ammonia (annually). See emission calculations' table above for RATA test data.

1. Permit deviations for PM Opacity exceedances caused by poor fuel quality, equipment & process problems were reported by the facility, and they failed the PM Compliance stack test conducted on May 20, 2015. The stack test performed on May 20, 2015 yielded the failing result of 0.16 lb/MMBtu for particulate matter (the PM limit is 0.10 lb/MMBtu). Subsequently, repairs were performed on the ESP, and the test was repeated on June 30, 2015 yielding a passing result. A consent decree between the department and the facility was reached in August 2016, and the facility was fined. Refer to www.doj.nh.gov/media-center /press-releases/2016/20160831-whitefield-fine.htm for more information.
2. The last RATA test for ammonia slip was completed in June 15, 2017 which yielded a passing result (1.5 ppm @6% O2) and is in compliance. The formal report for 2017 is in the file and dated 9/15/2017. The 2016 RATA test data was used for this renewal review.
3. PM, NOx & CO – were stack tested on 6/9/2017 and are all in compliance. The PM limit of 0.10 lb/MMBtu was not exceeded. The PM average during testing was 0.02 lb/MMBtu.

MONITORING REQUIREMENTS

1. NOx - Continuous emissions monitoring (CEM) system is required to verify compliance with the PSD avoidance limit of 111.12 tpy of NOx for the boiler.
2. CO – CEM system is required to verify compliance with PSD avoidance limits for CO.
3. CO_2 - Monitor continuously.
4. Volumetric flow - Monitor continuously.
5. Opacity – The facility operates a continuous opacity monitoring (COM) system for the wood-fired boiler – The last test was in 4/5/2017 and in compliance.
6. Conduct quarterly audits and annual RATA for the CEM in accordance with Env-A 808 and 40 CFR 60.
7. The latest CEM QA/QC plan (Monitoring plan) was submitted to the department on 4/11/2013.
8. NH3 – Annual stack testing to verify compliance with ammonia slip limit
9. PM - Stack testing is required once every five years to verify compliance with the limit.
10. All monitoring reports and stack tests are available in the departments' electronic and paper files.

Reports

- For boiler EU01 - CEM, RAA, Emissions and other required reports (annual, semi-annual or quarterly) including permit deviation reports were submitted to the department over the past 5 years. A cursory review of the reports was done, and the reports were received by the department in a timely manner.
- For boiler EU01 - Pursuant to 40 CFR 63 Subpart JJJJJJ, the initial notification was submitted timely to the USEPA in 2011, and the notification of compliance status was submitted timely to the USEPA on June 17, 2014.
- For boiler EU01 - Pursuant to 40 CFR 63 Subpart JJJJJJ, the required energy assessment was performed on Jan. 24, 2014.
- Annual emissions report for 2016 for was submitted timely on March 13, 2017.

Fees

Annual emission fees for the facility are current through calendar year 2016.

Site Visits/Inspections

<u>**Date**</u>	<u>**Description**</u>
April 22, 2016	Onsite full compliance evaluation was conducted by the department. The On-Site Full Compliance Evaluation Report dated June 21, 2016 noted the PM Opacity exceedances as described above under "Emission Testing". All other permit requirements were in compliance during the inspection period 2014-2016.

REVIEW OF REGULATIONS

<u>**State Regulations**</u>

Env-A 300 – *National Ambient Air Quality Standards* - Applicable; Facility is in compliance with NAAQS

Env-A 600 – *Permitting*

- 607.01(c) – Applicable – The wood-fired boiler has a designed heat input rating greater than 2.0 MMBtu/hr.
- 607.01(d)(1) – Applicable - The emergency generator and fire pump are subject.

- 607.01(q) – Applicable – The wood-fired boiler is subject to NSPS Subpart Db.
- 609, *Title V Operating Permits* – Applicable – The facility is a major source for NOx and CO
- Env-A 618 *Additional Requirements in Non-Attainment Areas and the New Hampshire Portion of the Northeast Transport Region* – Not Applicable - The facility (in Coos county-attainment county for NOx) is considered an existing major source of NOx under the New Source Review (NSR) program, as historical NOx emissions were greater than 100 tons per year. Temporary Permit TP-B-0547 established a new NOx limit on EU1 to 111.12 tons per consecutive 12-month period to avoid NSR. This NOx limit was incorporated into Title V Permit TV-0007 as part of a permit modification.
- Env-A 619 *Prevention of Significant Deterioration* – Not applicable; facility is a synthetic minor source for carbon monoxide and NOx. Current Title V Permit TV-0007 limits CO and NOx emissions below the PSD major source threshold of 250 tons per consecutive 12-month period.

Env-A 700 - *Permit Fee System* - Applicable. Source is subject to annual emission-based fees.

Env-A 800 - *Testing & Monitoring Procedures* – Applicable.

Env-A 900 - *Owner/Operator Recordkeeping Obligations* –Applicable.

Env-A 1204, *VOC RACT* - Not applicable;

Env-A 1300, *NO_x RACT* – Applicable to EU01; the wood-fired boiler is subject to Env-A 1303.07(c)(1). NO_x RACT limit is 0.33 lb/MMBtu (24-hr calendar day average).

Env-A 1400, *Regulated Toxic Air Pollutants* - Applicable; Facility is in compliance.

Env-A 1604, *Maximum Sulfur Content Allowable in Liquid Fuels* -Applicable

Env-A 2000, *Fuel Burning Devices* - Applicable

Env-A 3200, *NO_x Budget Trading Program* - This rule is not applicable to wood-fired boilers.

Env-A 3700, *NO_x Emissions Reduction Fund* - Not applicable

Env-A 4200, *CO_2 Budget Trading Program*[3] - Not applicable

<u>Federal Regulations</u>

<u>40 CFR 60, New Source Performance Standards (NSPS)</u>

- *Subpart Db Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units (> 100 MMBtu/hr)* – Applicable to EU1 – Design heat input rating of wood-fired boiler is greater than 100 MMBtu/hr.
- Part 60.44b *Standards for NOx* – Not applicable -facility is not subject to this part in accordance with 60.44b(k).
- Part 60.42b *Standards for SO_2* – Not applicable.
- Part 60.43b *Standards for PM.* The facility is subject to this part and shall limit the emissions from PM to 0.10 lb/mmBTU heat input in accordance with Part 60.43b(c)(1).

<u>40 CFR 63, National Emission Standards for Hazardous Air Pollutants (NESHAP)</u>

- *Subpart JJJJJJ* – Applicable. Facility is not a major source of HAP (<10 tpy for any single HAP, < 25 tpy for all HAPs combined), but it is an area source; therefore, the wood-fired boiler is subject to the following requirements:
    1. Conduct a tune-up of the boiler every five years as specified in 40 CFR 63.11223 (the boiler is equipped with an oxygen trim system); and
    2. The facility conducted a one-time energy assessment performed by a qualified energy assessor in January 2014. See the Monitoring Requirements Section (Reports) above for the notification reports that have been submitted.
- *Subpart ZZZZ* – Applicable. Facility's emergency generator and fire pump engines installed before 2006. Engines will be subject to certain work practices, operating standards and operating hour limits.

<u>40 CFR 64, Compliance Assurance Monitoring (CAM)</u> – Applicable. No changes to CAM as part of this permitting action. Current CAM requirements for PM are listed in Tables 6A and 6B of the Title V Permit TV-0007.

---

[3] This rule is applicable to <u>fossil fuel-fired</u> electricity generating units having a nameplate rated capacity ≥ 25 MW.

- The CAM rule applies to Title V sources that operate emission units with pre-controlled potential emissions at or above the major source thresholds that rely on control devices to comply with applicable requirements. The purpose of CAM is to provide a reasonable assurance of compliance with the applicable requirements and emission standards. CAM rule establishes criteria for monitoring, recordkeeping and reporting that should be conducted by the facility to provide a reasonable assurance of compliance with the emission limits and standards.

- This facility has pre-controlled PM emissions of greater than 100 TPY. A multiclone in series with an ESP are used to control PM emissions. Hence, the CAM rule is applicable to PM emissions from the wood fired boiler. The facility is also a major Title V source for NOx and CO. The facility has CEMS for NOx and CO.

- Based on stack tests and historical operational data for the ESP, as long as all the three ESP fields are operating, the facility will be in compliance with the PM limit. Also, the secondary voltage for each field must be maintained between 15 and 60 kv. The pressure drop across the multiclone must be maintained between 2-6 inches of water. Tables 6A and 6B of the Title V Permit outline various monitoring requirements that will assure the facility's compliance with the PM limit.

CAA 112(r)(1), Prevention of Accidental Releases

The facility does not store any chemicals above the 112(r) applicability thresholds. Therefore, facility is only subject to general duty clause of the CAA 112(r)(1).

New Source Review (NSR)/Prevention of Significant Deterioration (PSD) Programs

- NSR: This facility is a major source of NOx under the NSR Program, as actual NOx emissions have exceeded 100 tons per year, the major source threshold for sources located in Coos County. Facility accepted a NOx limit of 111.12 tpy for the boiler in conjunction with permitting of boiler modifications in order to avoid NSR requirements in the Ozone Transport Region (OTR).

- PSD: This facility is a synthetic minor source under PSD for CO and NOx. Current Title V Permit TV-0007 limits CO and NOx emissions below the PSD major source threshold of 250 tons per consecutive 12-month period.

Attachment C

Journal
Journal of Environmental Science and Health, Part A
Toxic/Hazardous Substances and Environmental Engineering
Volume 33, 1998 - Issue 2

Original Articles

Emissions of volatile organic compounds from large-scale incineration plants

X. J. Zhang

Pages 279-306 | Received 28 Sep 1997, Published online: 15 Dec 2008
Download citation https://doi.org/10.1080/10934529809376732

Abstract

This paper gives results of the measurements and evaluation of emissions from seven Swedish incineration plants. The investigated incinerators ranged from 12 to 80 MW, and include Martin grate, Von Roll grate, Overthrust (W+E) grate, Vereinige Kesselwerke (V+K) grate, travelling grate, vibration grate and circulating fluidized bed (CFB) types. The analytical techniques used include online carbon monoxide (CO), nitrogen oxides (NO_X), sulfur dioxide (SO_2), particulate matter (PM), carbon dioxide (CO_2), combustion and flue gas temperatures, gas chromatography and mass spectrometry (GC/MS), using Tenax as adsorbent. A number of volatile organic compounds (VOCs) were identified and quantified. The effects of waste compositions, size of incinerators, air pollution control systems on the VOCs in flue gas were investigated. Overall combustion characteristics such as waste compositions, carbon monoxide incinerator output have been related to the emissions of total volatile organic compounds (TVOCs).

The results show that these large-scale incinerators have low VOC emissions, ranging from 0.07 to 0.90 mg/nm after the flue-gas cleaning systems. The efficiency of air pollution control (APC) systems in reducing VOCs ranged from 26.1 to 90.4 *%.* High efficiency was found in the new systems with lime reactors and textile filters. Results from two incinerators showed that electrostatic precipitators had no effect on reducing VOCs. High TVOC emissions occurred in two plants when the moisture and plastic contents of the refuse were high. The relationship between CO and TVOC was also indicated, although incinerators, combustion conditions, flue gas cleaning systems and fuels are all confounding factors.

Key words: Emission, incineration, volatile organic compound (VOC).

Attachment D

International Journal of
Environmental Research and Public Health

MDPI

Article

Characteristics of Particulate Matter and Volatile Organic Compound Emissions from the Combustion of Waste Vinyl

Mona Loraine M. Barabad [1,2], Wonseok Jung [1], Michael E. Versoza [1,2], Yong-il Lee [1], Kyomin Choi [1] and Duckshin Park [1,*]

1 Korea Railroad Research Institute, Uiwang City 437-757, Korea; mlmbarabad@gmail.com (M.L.M.B.); worship611@krri.re.kr (W.J.); mikeverz23@krri.re.kr (M.E.V.); freego83@krri.re.kr (Y.-i.L.); kmchoi@krri.re.kr (K.C.)

2 Railway System Engineering, University of Science and Technology, Daejeon City 34113, Korea

* Correspondence: dspark@krri.re.kr; Tel.: +82-10-3343-2862

Received: 30 April 2018; Accepted: 27 June 2018; Published: 2 July 2018

Abstract: Vinyl samples were burned in a controlled environment to determine the characteristics of particulate matter (PM) and volatile organic compound (VOC) emissions during the combustion process. Open burning of plastic or vinyl products poses several environmental and health risks in developed and developing countries, due to the release of high concentrations of harmful pollutants. The production of fine and ultrafine particles was significant. At a heat flux of 25 kW/m^2, the production of PM of 0.35 μm in size was highest at 63.0 μg/m^3. In comparison, at fluxes of 35 and 50 kW/m^2, the production of PM of 0.45 μm in size was highest with values of 67.8 and 87.7 μg/m^3, respectively. Benzene, acetone, and other toxic compounds were also identified in the analyses.

Keywords: combustion; emission; PM; VOCs; waste vinyl

1. Introduction

According to the World Bank and Organization for Economic Cooperation and Development (OECD), countries generate 572 million tons of solid waste annually at an average of 2.2 kg/person/day (range 1.1–3.7) [1]. Projections for each country have been made based on the expected gross domestic product (GDP), and generation of average municipal solid waste (MSW), which are related to income level (IEA Annual Energy Outlook, 2005). Due to the increase in plastic utilization, open garbage burning occurs in areas where collection and organized waste handling measures are not implemented or are inadequate, even in urban areas, including backyard burning and open dump burning in developing countries [2,3]. In developed countries, open garbage burning is usually done in the backyards of houses in rural areas [4]. The World Bank reported that MSW has been used as fuel. Plastic, which is one waste component, comprised 0.9–9.5% of the waste in China in 1993 and 4.9% in Manila in 1997 [5]. China is a region of great concern for open burning, as it is estimated to have among the highest levels of total waste production and emissions [6]. In Tanzania, large amounts of plastic waste are commonly dumped in landfills and about 60% of the domestic solid waste is subjected to open burning daily [7]. According to the United States Environmental Protection Agency (USEPA), greenhouse gases (GHG) such as carbon dioxide (82% of all GHG emissions in the United States in 2015) are released from the incineration of municipal waste. Garbage burning is also a major source of particulate chloride and particulate matter smaller than 2.5 μm in size ($PM_{2.5}$) in Mexico City [2]. Furthermore, it is the main global source of dioxins and several other air pollutants [8].

Burning plastics release high concentrations of extractable organic compounds that cause various problems in developing and developed countries. Open waste burning poses environmental and health risks to those who are exposed to the smoke. In India, landfills are notable threats, as large amounts of plastic were burned and dumped with other wastes, contributing to GHG emissions [9]. Human Rights Watch (HRW) in Lebanon reported several cases of people suffering from respiratory issues including chronic obstructive pulmonary disease (COPD), coughing, throat irritation and asthma due to inhalation of smoke from the open burning of waste [10]. It has been reported that those living near incinerators have a higher prevalence of respiratory syndromes [11], such as asthma in children in Sydney, Australia [12], and chronic exposure to waste incinerators increases cancer of the larynx [13]. The USEPA also reported that the release of particulate matter (PM) through trash burning can cause deterioration in individuals with pre-existing conditions such as bronchitis, asthma, and emphysema [14]. In addition, backyard burning releases pollutants at ground level. Thus, dilution by dispersion is minimal, which may result in accumulation of pollution near the source and high measured concentrations of pollutants (e.g., dioxins) [15,16]. A detailed summary describing the health effects of waste incineration has been published and stated that ambient concentrations of various pollutants (from waste burning) could pose health risks [17].

Particulate matter less than 10 µm diameter (PM_{10}) is produced by the burning of waste and vinyl materials. This study determined the characteristics of PM_{10} and ultrafine particles produced during the combustion of vinyl in a controlled environment (cone calorimeter). Harmful compounds were also assessed, including the different volatile organic compounds (VOCs) emitted in the process.

2. Materials and Methods

Figure 1 shows a schematic diagram of the experimental set-up. A dual-cone calorimeter was used to examine the production of PM and VOCs from vinyl samples burned at different temperatures. The specifics of the burning process using the cone calorimeter were given in our previous study [18]. The cone-shaped radiating electric heater can emit up to 100 kW/m^2. In this study, the strength of the electric heater was set to 25, 35, and 50 kW/m^2; the radiation strength of the heater was based on ISO-5660-1 as a test of the reaction to fire (heat release, smoke production, and mass loss rate). Part 1 specifically describes the HRR (heat release rate; cone calorimeter method) and smoke production rate (dynamic measurement). The mass remaining, as well as O_2, CO and CO_2 produced at different temperatures, were measured.

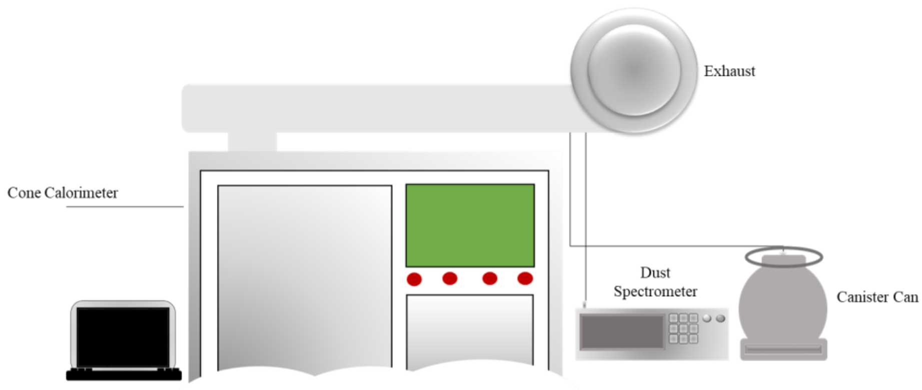


Figure 1. Schematic diagram showing the experimental set-up of the dual-cone calorimeter.

The plastic sample was collected in a rural village near Andong, a small city in South Korea. Low-density polyethylene (LDPE) plastic film is used for farming in villages. This type of waste is categorized as agricultural waste, which is collected and processed either through landfilling, recycling or incineration. Depending on the burning conditions and parameters set, a series of 2–3 burn cycles were carried out at each temperature. Vinyl samples weighing approximately 10 g were cut and positioned inside the sample holder, which measured 100 × 100 × 36 mm^3 (W × L × H), balanced and then a final weighed was recorded. During the test, aluminum foil was placed around the holder and gas analyzers (N_2, CO, CO_2, and O_2) before calibration. To control the initial conditions, the gas flow rate and concentration were also monitored. The flow rate, the weight of burned vinyl, and other parameters were stored in the software of the cone calorimeter. To measure the size contribution, an aerosol spectrometer (GRIMM 1.129 SKY OPC) with a measurement range of 0.25 to 32 μm, and regulated flow rate (6 L/min) with an external vacuum pump that was controlled by a critical orifice was used. A 6 L Restek SilcoCan stainless steel canister coated with fused silica on the inside, with its inlet aligned with the aerosol spectrometer, was used to collect compounds from the air samples. The collected pre-concentrated samples were analyzed using gas chromatography/mass spectrometry (Agilent/HP-6890; Agilent Technologies, Inc. Savage, MD, USA).

3. Results

Table 1 shows the different characteristics of vinyl combustion using the cone calorimeter. The average mass of the samples was 13.0, 12.7, and 12.9 g at heat fluxes of 25, 35, and 50 kW/m^2, respectively.

Table 1. Combustion variables of vinyl measured using a cone calorimeter.

Heat Flux (kW/m^2)	Peak HRR	Mass (g) + Foil	Remaining Mass	Mass Lost (g)	O_2 (g)	CO (%)	CO_2 (%)
25	247.9 ± 42.0	13.0 ± 1.2	5.8 ± 0.5	7.3 ± 1.0	30	31	462.8
35	295.3 ± 27.6	12.7 ± 0.7	5.2 ± 0.2	7.5 ± 0.7	39.6	7.3	691.8
50	330.4 ± 51.7	12.9 ± 0.5	4.5 ± 0.4	8.3 ± 0.2	29.5	19.3	468.5

Post-combustion measurements revealed that approximately 55.9%, 59.3%, and 64.8% of the mass was removed at 25, 35, and 50 kW/m^2, respectively. The samples produced different amounts of O_2 consumption and percentages of CO and CO_2. CO production was highest at 25 kW/m^2 (31%), followed by 50 and 35 kW/m^2 (19.3% and 7.3% CO, respectively). CO_2 production was highest at 35 kW/m^2 (691.8%), followed by 50 and 25 kW/m^2 (468.5 and 462.8%, respectively). O_2 consumption was highest at 35 kW/m^2 (39.6 g), followed by 25 and 50 kW/m^2 (30 g and 29.5 g respectively). O_2 and CO_2 values were proportional, differing from those of CO; the highest amount of CO was produced at 25 kW/m^2, and the lowest amount was produced at 35 kW/m^2, whereas the opposite was true for O_2 and CO_2. Increased oxygen consumption could lead to more combustion, which increases the release of CO_2. However, when the O_2 consumption rate is lower, incomplete combustion can take place, leading to soot formation. During this process, soot (C) and CO_2 react and generate a greater percentage of CO. The maximum HRR was 330.4 ± 51.7 at 50 kW/m^2, followed by 295.3 ± 27.6 at 35 kW/m^2 and 247.9 ± 42.0 at 25 kW/m^2. Figure 2 shows the PM size distribution and concentrations from vinyl combustion. The majority of particles had smaller sizes (<PM_1) compared to $PM_{2.5}$ to PM_{10}. At 25 kW/m^2, the peak PM size was 0.35 μm (at 63.0 μg/m^3), whereas, the peak size at 35 and 50 kW/m^2 was 0.45 μm, with 67.8 and 87.7 μg/m^3, respectively. In addition, 0.45 μm had the highest peak concentration among all of the compounds, while 50 kW/m^2 obtained the highest concentrations compared to the other heat fluxes. However, there was an apparent increase in distribution from $PM_{2.5}$ to $PM_{8.75}$, as shown Figure 2.

The emissions factor (EF) was calculated using the following equation [15]:

$$F\left(\frac{\text{mg}}{\text{kg}}\right) = \frac{\text{concentration of pollutants}\left(\frac{\text{mg}}{\text{m}^3}\right)\text{ X flowrate}\left(\frac{m^3}{\text{min}}\right)\text{ X sampling time (min }\;)}{weight\ of\ burned\ vinyl\ sample\ (\text{kg})} \quad (1)$$

The highest EF (mg/kg) of PM in this study was for the smaller size range of 0.35–0.45 μm, as shown in Table 2.

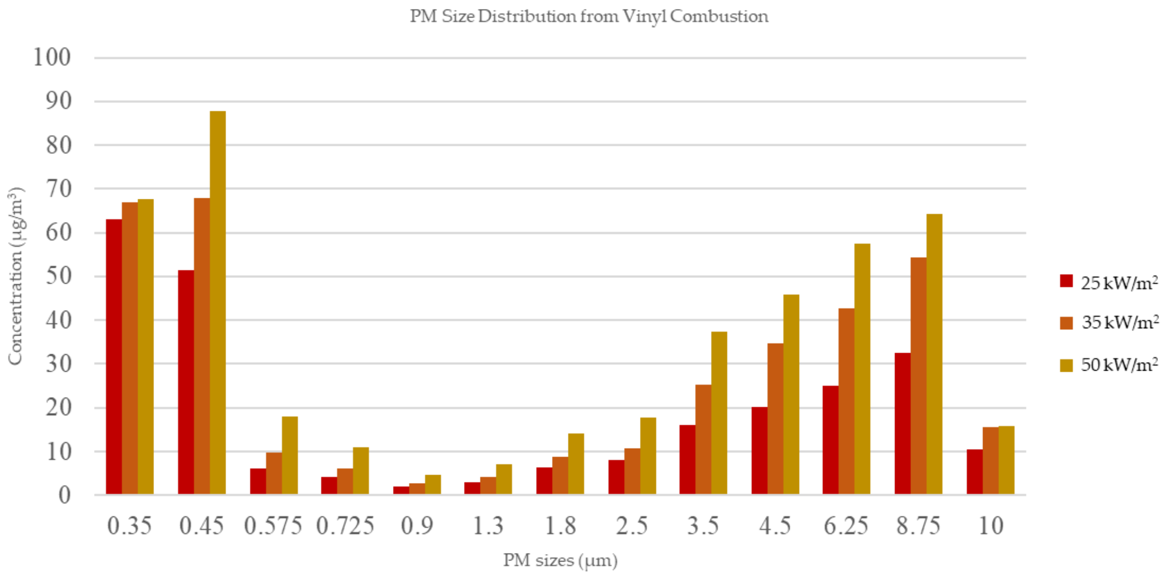


Figure 2. Particulate matter (PM) size distribution from vinyl combustion.

Table 2. The concentration of particulate matter released in the combustion of vinyl.

PM (µm)	25 kW/m^2	35 kW/m^2	50 kW/m^2
0.35	50.4 ± 5.2	53.5 ± 1.3	54.1 ± 1.0
0.45	41.2 ± 11.0	54.3 ± 1.5	70.2 ± 1.2
0.57	4.9 ± 1.6	7.8 ± 1.0	14.5 ± 2.0
0.725	3.3 ± 1.0	4.8 ± 0.5	9.0 ± 1.0
0.9	1.5 ± 0.5	2.1 ± 0.3	4.0 ± 0.2
1.3	2.5 ± 1.0	3.4 ± 0.5	6.0 ± 1.0
1.8	5.0 ± 1.5	7.0 ± 1.3	11.2 ± 1.3
2.5	6.4 ± 2.0	8.7 ± 1.5	14.2 ± 1.1
3.5	13.0 ± 3.0	20.3 ± 2.3	30.0 ± 3.2
4.5	16.2 ± 5.0	28.0 ± 4.2	37.0 ± 3.4
6.25	20.0 ± 8.3	34.2 ± 5.2	46.0 ± 6.2
8.75	26.0 ± 8.3	43.4 ± 11.0	51.5 ± 9.1
10	8.4 ± 3.3	12.5 ± 6.2	12.7 ± 3.0

At 25 kW/m^2, 0.35 µm particles had an EF of 50.4 ± 5.2 mg/kg, whereas, at 35 and 50 kW/m^2, 0.45 µm particles had the highest EF, at 54.3 ± 1.5 and 70.2 ± 1.2 mg/kg, respectively. At a heat flux of 50 kW/m^2, the majority of PM emissions from the vinyl combustion analysis ranged from less than PM_1 to PM_{10}.

Figure 3 shows the concentrations of VOCs from vinyl combustion at different temperatures. Of the compounds detected, benzene was the most common, comprising 30.7%, 38.3%, and 34.4% at 25, 35, and 50 kW/m^2, respectively. Acetone comprised 26.0%, 11.2%, and 20.0% at 25, 35, and 50 kW/m^2. Isopropyl alcohol was only produced with heat fluxes of 35 and 50 kW/m^2, comprising 20.0% and 9.6%, respectively. By contrast, methyl ethyl ketone comprised 7.3% and 4.4% of the total at 25 and 35 kW/m^2, respectively. 2-Hexaneone comprised 10.0%, 4.2%, and 2.3% for 25, 35, and 50 kW/m^2, respectively, whereas toluene comprised 6.2%, 4.2%, and 4.4%. Table 3 shows the VOCs emitted in vinyl combustion and the results also varied with the heat fluxes.

The concentrations of a few of the compounds produced exceeded 100 mg/kg. Benzene comprised 277.8 ± 14.6, 479.8 ± 19.4, and 320.0 ± 22.5 mg/kg at fluxes of 25, 35, and 50 kW/m^2, respectively; followed by acetone at 232.0 ± 34.2, 140.0 ± 16.6, and 184.5 ± 35.0 mg/kg. The production of isopropyl alcohol also exceeded 100 mg/kg, but only at a flux of 35 kW/m^2 with 250.8 ± 24.0. Several compounds exceeded 50 mg/kg at selected fluxes, including isopropyl alcohol at 50 kW/m^2, methyl ethyl ketone at

25 and 35 kW/m^2, 2-hexaneone at 25 and 35 kW/m^2, and toluene at all three heat fluxes. Some other compounds were produced in lesser amounts or were not detected as shown in Table 4.

Table 3. Experimental results (ug/m^3) of VOC from vinyl combustion.

Compounds	25 kW/m^2	35 kW/m^2	50 kW/m^2
Acetone	290.05	174.94	230.65
Isopropyl alcohol	17.10	313.45	111.81
Methyl ethyl ketone	82.72	68.67	ND
Ethyl acetate	11.60	21.20	21.73
Hexane	18.57	14.75	4.53
Tetrahydrofuran	26.17	16.54	31.03
Benzene	347.25	599.79	400.02
Heptane	17.60	4.11	3.21
Methyl isobutyl ketone	3.60	4.20	ND
Toluene	70.03	65.76	50.94
2-Hexaneone	112.90	66.19	24.93
Ethylbenzene	9.16	8.99	5.05
m,p-Xylene	0.882	28.74	1.32
Styrene	31.043	33.88	19.39
o-Xylene	2.97	7.14	43.27
4-Ethyltoluene	5.65	0.52	12.56
1,3,5-Trimethylbenzene	4.64	12.83	10.54
1,2,4-Trimethylbenzene	14.45	22.64	40.95
Benzyl chloride	ND	3.25	4.04
1,4-Dichlorobenzene	1.30	3.71	7.49
1,3-Dichlorobenzene	6.97	11.60	25.67
1,2-Dichlorobenzene	3.01	7.20	9.68
1,2,4-Trichlorobenzene	44.03	74.51	47.92
Hexachloro-1,3-butadiende	10.06	ND	54.71
Total:	1131.77	1564.62	1161.43

ND. Not Detected.

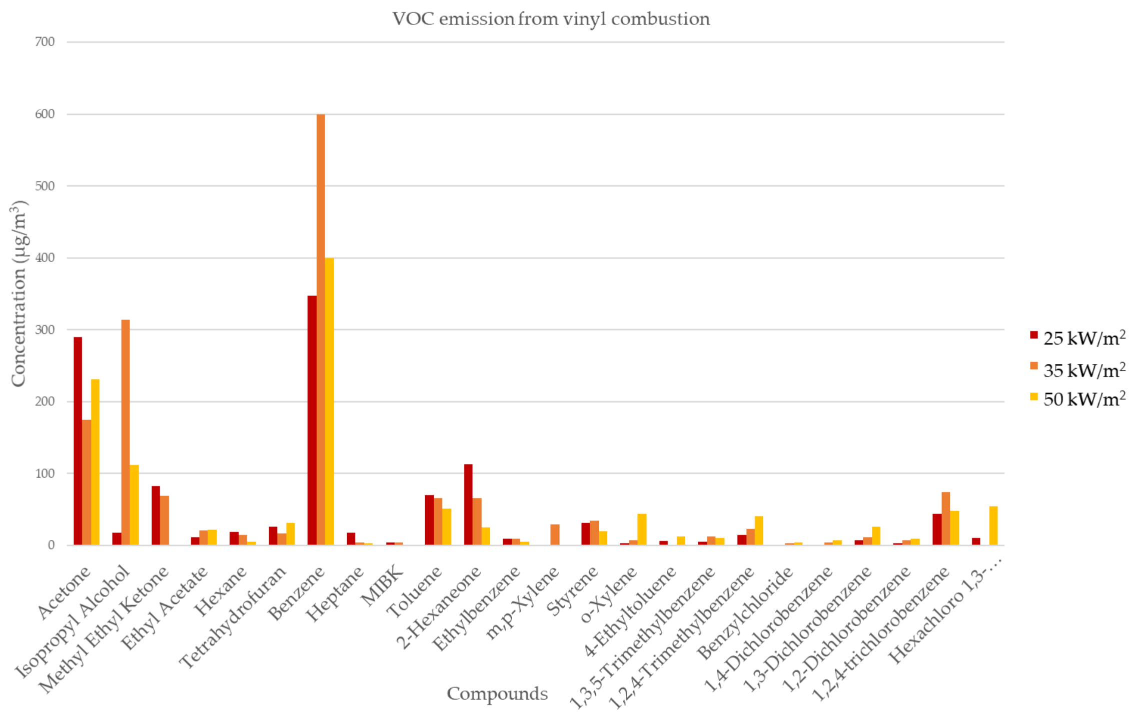


Figure 3. Volatile organic compound emissions from vinyl combustion.

Table 4. Emission factors (mg/kg) of VOCs from the combustion of vinyl.

Compounds	25 kW/m^2	35 kW/m^2	50 kW/m^2
Acetone	232.0 ± 34.2	140.0 ± 16.6	184.5 ± 35.0
Isopropyl Alcohol	13.4 ± 4.9	250.8 ± 2.4	89.4 ± 11.3
Methyl Ethyl Ketone	66.2 ± 14.0	54.9 ± 8.0	ND
Ethyl Acetate	9.3 ± 1.7	17.0 ± 2.8	17.4 ± 0.3
Hexane	14.9 ± 2.1	11.8 ± 1.4	3.6 ± 0.6
Tetrahydrofuran	20.9 ± 0.3	13.2 ± 2.9	24.8 ± 4.9
Benzene	277.8 ± 14.6	479.8 ± 19.4	320.0 ± 22.5
Heptane	14.1 ± 1.9	3.3 ± 0.4	2.6 ± 0.4
MIBK	2.9 ± 0.4	3.4 ± 0.4	ND
Toluene	56.0 ± 3.6	52.6 ± 3.4	40.8 ± 2.5
2-Hexaneone	90.3 ± 14.7	53.0 ± 1.2	19.9 ± 1.5
Ethylbenzene	7.3 ± 0.9	7.2 ± 0.8	4.0 ± 0.0
m,p-Xylene	0.7 ± 0.1	23.0 ± 0.8	1.1 ± 0.3
Styrene	24.8 ± 4.8	27.1 ± 5.4	15.5 ± 2.4
o-Xylene	2.4 ± 0.4	5.7 ± 0.4	34.6 ± 12.7
4-Ethyltoluene	4.5 ± 0.4	0.4 ± 0.1	10.0 ± 2.1
1,3,5-Trimethylbenzene	3.7 ± 0.6	10.3 ± 2.3	8.4 ± 2.6
1,2,4-Trimethylbenzene	11.6 ± 1.0	18.1 ± 2.1	32.8 ± 3.8
Benzylchloride	ND	2.6 ± 0.2	3.2 ± 0.4
1,4-Dichlorobenzene	1.0 ± 0.2	3.0 ± 0.7	6.0 ± 1.1
1,3-Dichlorobenzene	5.6 ± 0.5	9.3 ± 1.5	20.5 ± 2.0
1,2-Dichlorobenzene	2.4 ± 0.3	5.8 ± 1.1	7.7 ± 1.4
1,2,4-trichlorobenzene	35.2 ± 1.6	59.6 ± 2.5	38.3 ± 4.9
Hexachloro 1,3-Butadiende	8.0 ± 0.6	0.0 ± 1.4	43.8 ± 2.4

ND. Not Detected.

4. Discussion

Burning of waste is a source of air pollutants [19] that potentially contribute to environmental and health problems. Emission characteristics associated with the combustion of vinyl differ according to various parameters. In the current study, PM and VOC emissions from the cone calorimeter varied by combustion temperature. CO levels were lower compared to a study conducted in Mexico City, in which different plastic materials (e.g., bottles, bags, buckets) collected from several urban areas were burned; high emissions of CO were detected, which likely resulted from the burning of a high proportion of ethylene-based plastic polymers [20]. According to Font et al., CO emissions are affected by temperature; thus, when the temperature increases, carbon oxides decrease [21]. CO values were highest when a heat flux of 25 kW/m^2 was applied. In addition, according to Lindholm et al., CO is a result of incomplete combustion and can be a major product if flame retardants disrupted the burning process [22].

In this study, PM emission characteristics were measured in a controlled environment. Of the analyzed particles, ultrafine particles (<PM_1) occurred at the highest concentration. The total percentages (%) emitted from particles ranging in size from 0.35 μm to 0.9 μm were 53.3, 64.5, and 79.6, explaining the greater concentration of smaller-sized particles with heat fluxes of 25, 35 and 50 kW/m^2, respectively. The total PM_{10} concentration produced at heat fluxes of 25, 35, and 50 kW/m^2 was 237.6, 334.0, and 433.1 μg/m^3, respectively. In this study, the characteristics of PM_{10} and $PM_{2.5}$ can be compared to those in previous work that studied emissions from the combustion of plastic products. One study reported that 20.6 mg/g (0.020573 mg/kg) of $PM_{2.5}$ was collected from a single waste incinerator [23]. This value was lower compared to our results, where we observed values of 190.1, 267.2, and 346.5 mg/kg with heat fluxes of 25, 35, and 50 kW/m^2, respectively. However, other research estimated emission amounts of about 10.5 ± 8.8 g/kg [17] and 11.3 ± 7.5 g/kg [7], roughly 10 times higher than our values, which might be due to the larger sample area and amount of the materials used in that experiment.

We also characterized VOC emissions and found that notable compounds were produced. The highest concentration of total VOC (TVOC) was obtained at a heat flux of 35 kW/m^2 (1564.6 $\mu g/m^3$). Results at 50 and 25 kW/m^2 were similar (1161.4 and 1131.8 $\mu g/m^3$, respectively). Benzene contributed the highest concentration to TVOC at 25, 35, and 50 kW/m^2. Lemieux et al. summarized the test data generated by application of recyclers and non-recyclers for burning waste [24]. Emission products of benzene, acetone and styrene were all significant and higher than the values in our study. Styrene comprised only 2.7%, 2.7%, and 1.2% of the TVOC collected with heat fluxes of 25, 35 and 50 kW/m^2, respectively. In addition, another study described 1,3,5 triphenylbenzene as a useful marker of the burning of plastic products in domestic waste and litter [25]; however, 1,3,5 triphenylbenzene was barely detected in our study.

Our research was conducted in the context of a controlled laboratory set-up. Several parameters were closely regulated; hence, the results may differ from actual burning conditions (i.e., open/barrel burning). Emissions from open burning can be several orders of magnitude higher compared to those of controlled combustion [24]. The results from this study presented that the heatflux characteristics could be a notable factor in the size distribution and concentration. The greatest concentrations found in this study were from ultrafine to fine particles. However, at the temperatures applied, we also observed an increase in concentrations of particles in the range of PM 3.5 μm to 8.75 μm, this trend was observed from all heatfluxes. PM emission and size distribution largely depends on the combustion conditions, where fast pyrolysis and high combustion temperatures may cause incomplete combustion [19]. Flame residence time [25] is another factor that can determine the emission products arising from incomplete combustion. To achieve complete combustion, gases produced must remain in the high-temperature zone of the furnace for a minimum residence time of 1–2 s [17]. The study can assume that when the plastic sample was under a combustion process, ultrafine and PM_{10} released with significant results. At temperatures between 700 to 800 °C, benzene and toluene were produced in significant amounts from the combustion of polyethylene (e.g., garbage bags, grain storage bags, and shopping bags) [26]. In contrast, some oxygenated compounds have also been identified in combustion experiments at low temperature [21]. Thus, temperature influences the characteristics of the particles and compounds emitted from the combustion process. However, here, the highest recorded concentration of benzene was emitted at a heat flux of 35 kW/m^2, which was neither the lowest nor the highest temperature used in this experiment. Although this research applied different heat fluxes, the characteristics of the temperature were not taken into consideration. Furthermore, flame residence time and the characteristics of the vinyl used in the combustion process were also not examined in detail.

Several ways of waste handling have been implemented in different countries. Developed countries apply methods such as recycling, incinerating, and discarding in landfills. Presently, as the Korean economy is rapidly growing, the immense amount of industrial waste produced is also increasing. Waste management in South Korea comprises several methods, of which incineration is one. Incineration is used to increase renewable energy production and to make use of non-recyclable and non-combustible waste (wet organic waste) [27,28]. Furthermore, incineration (in commercial incinerators, furnaces, etc.) plays an important role in industrial-waste energy production through heat energy recovery [28]. However, this study aimed to investigate the burning of plastic film, especially in the backyard context. Although household waste was reported to make up approximately 15% of the total amount of waste produced in South Korea, it is a significant target for renewable energy production. Overall, 17% (3.04 Mt) of household waste was incinerated, while recycling (57%) and landfilling (26%) were also utilized for waste management [28,29]. The Korean government introduced the volume-based waste fee (VBWF) system in 1995, in which local cities have a responsibility to collect, recycle, and treat solid waste from households, and small and large businesses. This method helped reduce waste generation and improved recycling in the MSW sector [30]. Another study investigated the removal efficiency of PM from furnaces. PM_{10} and $PM_{2.5}$ were the primary particles produced, with coarse particles more effectively removed compared to fine particles [31]. However, developing countries are still practicing open burning and waste dumping due to inadequate disposal technology. Plastics are combustible and can result in hazardous emissions when burned in an uncontrolled environment [3]. During waste combustion, suspension of PM due to dispersion is decreased, which contributes to high concentrations of toxic pollutants. Poor dispersion of emissions will lead to an increase in direct inhalation [24], which impacts both the ambient environment and human health.

5. Conclusions

Open burning of plastic and plastic related materials is still widely practiced in several countries because of poor waste handling. Here, we burned vinyl samples under controlled laboratory conditions using a cone calorimeter and analyzed the characteristics of the various pollutants emitted.

We observed significant differences between the abundance of PM_{10} and $PM_{2.5}$. The most abundant particle size was in the ultrafine range (<PM_1). The smallest-sized particles (0.35 and 0.45 μm) constituted the greatest percentage of total PM emissions. Many journals have reported the characteristics of PM_{10} and $PM_{2.5}$ emitted from waste or plastic burning. However, our investigation found that the concentration and emission characteristics of ultrafine particles were significant, which may be useful for future reference. Toxic by-products were also produced from the combustion process, including several VOCs, such as benzene, acetone, and isopropyl, which were dominant compared to other VOCs identified.

We identified several limitations to our methodology; thus, our results may differ from those observed under actual burning conditions (i.e., garbage or open barrel burning). However, we showed that coarse, ultrafine/fine particles and carcinogenic compounds were emitted under laboratory conditions. Exposure to these pollutants may cause environmental and health issues. Although different methods of waste management have been introduced in various countries, a lack of knowledge of the end products emitted represents a hindrance to successful management. Therefore, raising public awareness of proper methods of garbage disposal is necessary.

Author Contributions: D.S.P. and W.S.J. designed the experiment; M.L.M. Barabad and W.S.J. implemented the experimental process; M.L.M.B. and M.V. analyzed the data; D.S.P., W.S.J., Y.-i.L. and K.M.C. contributed the materials and tools for the experiment; M.L.M.B. wrote the manuscript.

Funding: This research was supported by a grant from the R&D Program of the Korea Railroad Research Institute, Republic of Korea. This research received no external funding.

Conflicts of Interest: The authors declare no conflicts of interest

References

1. World Bank. Urban Development Series–Knowledge Paper. Available online: https://siteresources.worldbank.org/INTURBANDEVELOPMENT/Resources/336387--1334852610766/What_a_Waste2012_Final.pdf (accessed on 4 March 2018).
2. Li, G.; Lei, W.; Bei, N.; Molina, L.T. Contribution of garbage burning to chloride and $PM_{2.5}$ in Mexico City. *Atmos. Chem. Phys.* **2012**, *12*, 8751–8761. [CrossRef]
3. Estrellan, C.R.; Iino, F. Toxic emissions from open burning. *Chemosphere* **2010**, *80*, 193–207. [CrossRef] [PubMed]
4. USEPA. *An Inventory of Sources and Environmental Releases of Dioxin-Like Compounds in the United States for the Years 1987, 1995, and 2000*; EPA/600/P-03/002F; National Center for Environmental Assessment, Office of Research and Development: Washington, DC, USA, 2006; p. 677.
5. Rand, T.; Haukohl, J.; Marxen, U. *Municipal Solid Waste Incineration: A Decision Maker's Guide*; The World Bank: Washington DC, USA, 2000; Available online: http://siteresources.worldbank.org/INTUSWM/Resources/463617-1202332338898/incineration-dmg.pdf (accessed on 4 March 2018).
6. Wiedinmyer, C.; Yokelson, R.J.; Gullet, B.K. Global emissions of trace gases, particulate matter, and hazardous air pollutants from open burning of domestic waste. *Environ. Sci. Technol.* **2014**, *48*, 9523–9530. [CrossRef] [PubMed]

7. Kassim, S.M. Sustainability of Private Sector in Solid Waste Collection: A Case of Dar es Salaam Tanzania. 2006. Available online: https://dspace.lboro.ac.uk/2134/2336 (accessed on 23 April 2018).
8. Lemieux, P.M.; Lutes, C.C.; Abbott, J.A.; Aldous, K.M. Emissions of polychlorinated dibenzo-*p*-dioxins and polychlorinated dibenzofurans from the open burning of household waste in barrels. *Environ. Sci. Technol.* **2000**, *34*, 377–384. [CrossRef]
9. Verma, R.; Vinoda, K.S.; Papireddy, M.; Gowda, A.N.S. Toxic pollutants from plastic waste—A review. *Procedia Environ. Sci.* **2016**, *35*, 701–708. [CrossRef]
10. Human Rights Watch: "As if You're Inhaling Your Death". The Health Risks of Burning Waste in Lebanon. 2017. Available online: https://www.hrw.org/sites/default/files/report_pdf/lebanon1117_web_1.pdf (accessed on 23 April 2018).
11. Wang, J.Y.; Hsiue, T.R.; Chen, H.I. Bronchial responsiveness in an area of air pollution resulting from wire reclamation. *Arch. Dis. Child.* **1992**, *67*, 488–490. [CrossRef] [PubMed]
12. Gray, E.J.; Peat, J.K.; Mellis, C.M.; Harrington, J.; Woolcock, A.J. Asthma severity and morbidity in a population sample of Sydney school children: Part I–Prevalence and effect of air pollutants in coastal regions. *Aust. N. Z. J. Med.* **1994**, *24*, 168–175. [CrossRef] [PubMed]
13. Fingerhut, M.A.; Halperin, W.E.; Marlow, D.A.; Piacitelli, L.A.; Honchar, P.A.; Sweeney, M.H.; Greife, A.L.; Dill, P.A.; Steenland, K.; Suruda, A.J. Cancer mortality in workers exposed to 2,3,7,8-tetrachlorodibenzo-p-dioxin. *N. Engl. J. Med.* **1991**, *324*, 212–218. [CrossRef] [PubMed]
14. EPA Web Archives. Available online: https://archive.epa.gov/epawaste/nonhaz/municipal/web/html/index-3.html (accessed on 16 April 2018).
15. National Air Quality Management Programme. *Air Pollution Dispersion and Topographical Effects*; Publication Series B: Book 7 of National Air Quality Management Programme Phase II Transition Project, Air Quality Management & Climate Change; Department of Environmental Affairs and Tourism Environmental Quality and Protection Chief Directorate: Pretoria, South Africa, 2016; p. 1.
16. Wevers, M.; De Fre, R.; Desmedt, M. Effect of backyard burning on dioxin deposition and air concentrations. *Chemosphere* **2004**, *54*, 1351–1356. [CrossRef]
17. *Understanding Health Effects of Incineration—Waste Incineration and Public Health (NCBI Bookshelf)*; National Academies Press: Washington, DC, USA, 2000. [CrossRef]
18. Park, D.S.; Barabad, M.L.; Lee, G.J.; Kwon, S.B.; Cho, Y.M.; Lee, D.H.; Cho, K.C.; Lee, K.Y. Emission characteristics of particulate matter and volatile organic compounds in cow dung combustion. *Environ. Sci. Technol.* **2013**, *47*, 12952–12957. [CrossRef] [PubMed]
19. Maasikmets, M.; Kupri, H.-L.; Teinemaa, E.; Vainumae, K.; Arumae, T.; Roots, O.; Kimmel, V. Emissions from burning municipal solid waste and wood in domestic heaters. *Atmos. Pollut. Res.* **2016**, *7*, 438–446. [CrossRef]
20. Christian, T.J.; Yokelson, R.J.; Cardenas, B.; Molina, L.T.; Engling, G.; Hsu, S.-C. Trace gas and particle emissions from domestic and industrial biofuel use and garbage burning in central Mexico. *Atmos. Chem. Phys.* **2010**, *10*, 565–584. [CrossRef]
21. Font, R.; Aracil, I.; Fullana, A.; Conesa, J.A. Semivolatile and volatile compounds in combustion of polyethylene. *Chemosphere* **2004**, *57*, 615–627. [CrossRef] [PubMed]
22. Lindholm, J.; Brink, A.; Hupa, M. Cone Calorimeter—A Tool for Measuring Heat Release Rate. Available online: http://www.ffrc.fi/FlameDays_2009/4B/LindholmPaper.pdf (accessed on 6 June 2018).
23. Yan, F.; Zhu, F.; Wang, Q.; Xiong, Y. Preliminary study of PM2.5 formations during the municipal solid waste incineration. *Procedia Environ. Sci.* **2016**, *31*, 475–481. [CrossRef]
24. Lemieux, P.M. *Evaluation of Emissions from the Open Burning of Household Waste in Barrels: Volume 1. Technical Report*; U.S. Environmental Protection Agency, National Risk Management Research Laboratory: Washington, DC, USA, 1997; 70p.
25. Simoneit, B.R.T.; Medeiros, P.M.; Didyk, B.M. Combustion products of plastics as indicators for refuse burning in the atmosphere. *Environ. Sci. Technol.* **2005**, *39*, 6961–6970. [CrossRef] [PubMed]
26. Font, R.; Aracil, I.; Fullana, A.; Gullon, I.M.; Conesa, J.A. Semivolatile compounds in pyrolysis of polyethylene. *J. Anal. Appl. Pyrolysis* **2003**, *68–69*, 599–611. [CrossRef]
27. Ministry of Environment. *Waste in Energy Strategic Plan*; Ministry of Environment: Gwacheon, Korea, 2008. (In Korean)

28. Ryu, C. Potential of municipal solid waste for renewable energy production and reduction of Greenhouse gas emissions in South Korea. *J. Air Waste Manag. Assoc.* **2010**, *60*, 176–183. [CrossRef] [PubMed]
29. Ministry of Environment. *White Paper in Environment*; Ministry of Environment: Gwacheon, Korea, 2008. (In Korean)
30. Korea Environmental Policy Bulletin (Volume-Based Waste Fee System in Korea). 2006. Available online: http://eng.me.go.kr/eng/file/readDownloadFile.do;jsessionid=5iu1EdBTzFcpz6DbuVPif7nrjNBER2UT4RZANstftx2njZsqquNXadaD0ctMEKMy.meweb1vhost_servlet_engine3?fileId=92436&fileSeq=1 (accessed on 4 March 2018).
31. Shiota, K.; Tsujimoto, Y.; Takaoka, M.; Oshita, K.; Fujimori, T. Emission of particulate matter from gasification and melting furnace for municipal solid waste in Japan. *J. Environ. Chem. Eng.* **2017**, *5*, 1703–1710. [CrossRef]

Attachment E

OPTIMISING DRY SORBENT INJECTION TECHNOLOGY

MELISSA SEWELL AND JERRY HUNT, LHOIST NORTH AMERICA, DISCUSS THE OPTIMISATION OF DRY SORBENT INJECTION TECHNOLOGY TO ACHIEVE HCL OR SO_2 REDUCTIONS WITHIN THE CEMENT INDUSTRY.

Introduction

The landscape of environmental regulations in the US is complex and continues to develop. It includes compliance deadlines for various hazardous air pollutants via the Portland Cement NESHAP (National Emission Standard for Hazardous Air Pollutants), NSPS (New Source Performance Standards) for new and significantly modified facilities, and site specific requirements based on consent decree agreements made with state and local environmental agencies or permit modifications that result in increased emission reductions for a number of acid gas species (i.e. SO_2, HCl, HF, SO_3), as well as mercury (Hg) and particulate matter. As a result of the need to comply with these stringent emission limits, there is a growing desire for a low cost/easy-to-install solution. Dry sorbent injection (DSI) technology can offer just that; a low capital cost solution with a relatively small equipment footprint, low power consumption and easy to retrofit to a majority of existing facilities, compared to alternative technologies such as wet and dry flue gas desulfurisation (FGD).

Generally, it is advantageous to utilise calcium hydroxide (commonly known as hydrated lime) as the sorbent of choice for DSI applications for the following reasons:

- Calcium-based sorbents are also found to provide little or no impact to residual properties in regards to heavy metal leaching, and provide greater opportunities for reuse or resale.
- In cement production specifically, alternative sorbents such as sodium cannot be added in any significant quantity due to the negative effect on the finished product.
- Calcium-based sorbents do not require onsite milling as typically required by sodium-based sorbents; therefore, calcium-based sorbents offer a lower capital and operating cost solution with a smaller equipment footprint and lower power consumption than sodium-based sorbents.
- Calcium-based sorbents do not generate NO_2, as is the case with several applications with sodium-based sorbents. NO_2 has been shown to negatively impact Hg emissions and powdered activated carbon (PAC) efficacy for Hg removal, resulting in increased PAC usage.
- There are a number of hydrated lime manufacturing facilities throughout the US; therefore most customer plants are within a close geographic proximity to allow for reasonable freight costs and rapid deliveries.

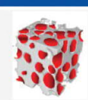
Sorbent	Standard Hydrated Lime	Sorbacal® H	Sorbacal® SP	Sorbacal® SPS	Units
Figure					–
Typical Available $Ca(OH)_2$	92 – 95	93	93	93	%
Typical Surface Area	14 – 18	> 20	~40	~40	m^2/g
Typical Pore Volume	~0.07	0.08	~0.20	~0.20	cm^3/g

Figure 1. Illustration of various hydrated lime particles and properties.

Over the past few years there have been significant design improvements to DSI systems based on operating experiences, which have increased DSI system design reliability and availability. Concurrently there have been developments to improve the performance of DSI sorbents (i.e. enhanced hydrated lime sorbents), such that a given level of acid gas removal can be achieved at lower sorbent injection rates, or alternatively an improved performance previously unattainable by past generation of DSI sorbents can now be achieved. Additionally, better understanding of the key factors in the effectiveness of DSI technology outside of the sorbents has resulted in significant improvements in the performance for DSI applications. This article discusses the development and application of Sorbacal® SP and Sorbacal® SPS, enhanced hydrated lime products that have been developed and engineered by Lhoist specifically for acid gas emission control applications, and how the performance of enhanced hydrated lime sorbents coupled with optimisation in the use of DSI technology have created effective compliance solutions within the cement industry for various acid gas control requirements.

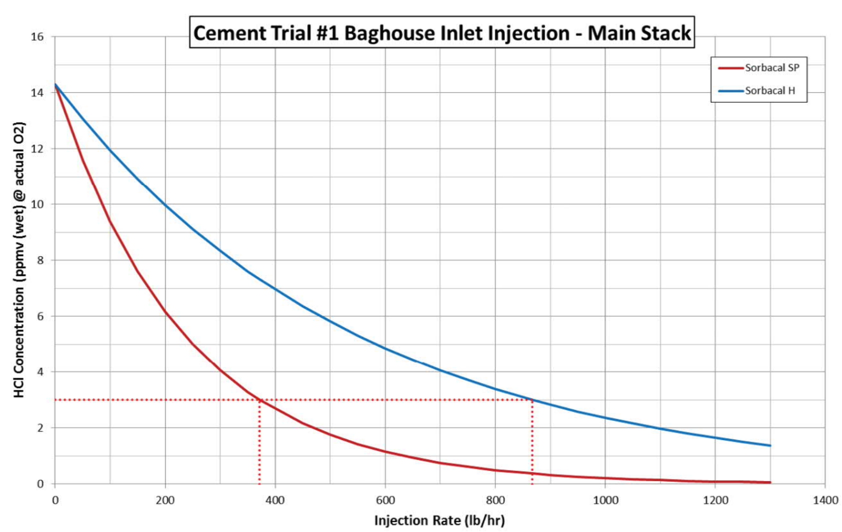


Figure 2. Comparison of standard hydrated lime versus enhanced hydrated lime sorbents.

Key factors in DSI performance and optimisation

The key factors in DSI effectiveness can be generalised into three main areas: sorbent properties, DSI system design configuration, and the site specific flue gas composition and operating conditions. All three factors together play a significant role in optimising the performance of any DSI system and are variables that should be considered on a case-by-case basis when evaluating DSI technology.

Sorbent properties and development

The first generation of enhanced hydrated lime sorbents (designated by Lhoist as Sorbacal® A) was developed in the 1980s by increasing the surface area to about 40 m²/g, which was twice that of a high quality hydrated lime. The high surface area combined with a small particle size gave Sorbacal® A a significant performance enhancement compared to standard hydrated lime.

During the acid removal reaction the rate is slowed down because the reaction product $CaSO_4$ forms a diffusion layer on the fresh unreacted $Ca(OH)_2$ material. More importantly, the reaction product $CaSO_4$ has a higher molar volume and thus gradually fills up the porosity of the sorbent.

Extensive research by the Lhoist group in the 1990s showed that indeed both the capture capacity and the reactivity of the sorbent scales directly with the pore volume. In contrast, the surface area was found to be contributing to a lesser extent. This research led to the development of a second generation of sorbents with both a higher pore volume >0.2 cm³/g (i.e. three times that of standard hydrated lime) and an even higher surface area >40 m²/g, which Lhoist designated as Sorbacal® SP. Laboratory scale, pilot scale and commercial scale tests have demonstrated that the reactivity of Sorbacal® SP can be up to twice that of high quality hydrated lime.

The third generation of sorbents is designated as Sorbacal® SPS and combines the exceptional pore structure properties of Sorbacal® SP with a chemical reaction enhancement obtained by surface coating. Sorbacal® SPS enables reaction rate enhancement of up to 30 to 50% over that of Sorbacal® SP. Today, Lhoist operates six Sorbacal® SP/SPS manufacturing locations in Europe, has licensed the technology to five Japanese plants and has one manufacturing location in the US, with plans for an additional two facilities to be operational in 2016. Figure 1 shows the characteristics of the different sorbents in graphical form and the main sorbent properties important in DSI applications.

One recent case study outlining the performance differences of standard hydrated lime (in this case Lhoist North America's Sorbacal® H) versus Sorbacal® SP enhanced hydrated lime is shown in Figure 2. In this example, DSI at a cement facility was applied at the inlet to the baghouse and the graph shows the reduction of HCl using various injection rates of two hydrated lime sorbents. This DSI trial demonstrated that, for similar HCl removal performance, more than double the amount of standard hydrated lime was required compared to the enhanced hydrated lime product, Sorbacal® SP.

DSI system configuration

Key design parameters include the sorbent distribution system and the particulate control device. DSI system operations rely on the hydrated lime particles making intimate contact with the acid gas distributed throughout the flue gas stream. If the sorbent distribution within the flue gas stream is not well balanced, some of the flue gas will not make contact

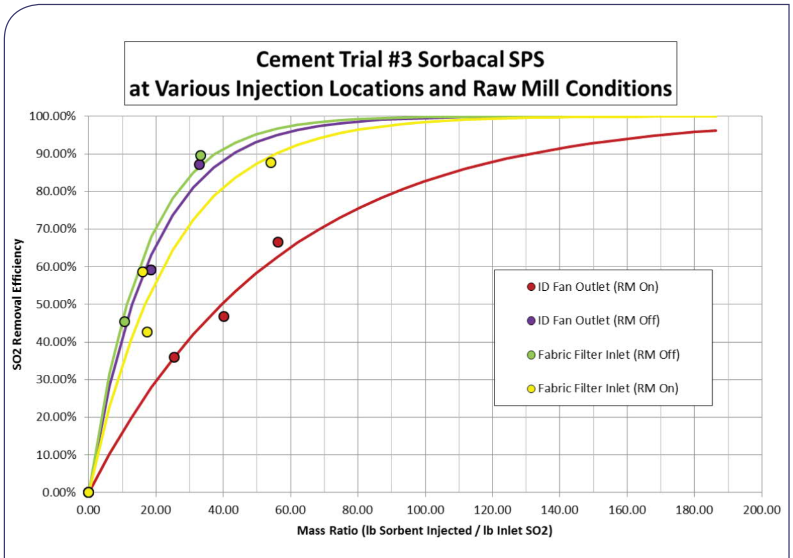


Figure 3. SO_2 removal efficiency at various injection locations.

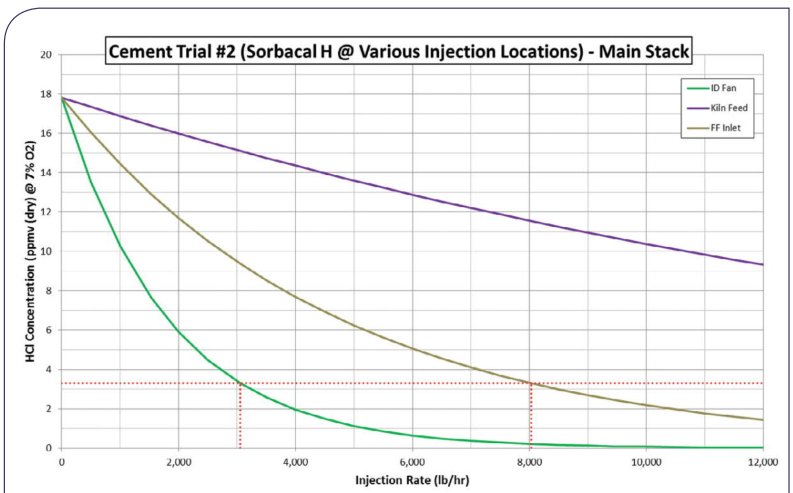


Figure 4. HCl removal efficiency at various injection locations.

with the hydrated lime, and therefore that portion of flue gas will be poorly treated or possibly untreated. Optimal injection location considerations are an important part of designing a successful DSI system; determination of the optimal location(s) may provide more opportunities for better mixing and/or may provide additional residence time leading to maximum sorbent utilisation possible. Improving the sorbent distribution through the use of a multi-injection lance grid, which is appropriately spaced across the width of the duct and at appropriate penetration depths into the duct, increased mixing using static mixers (or similar technologies), as well as increasing the residence time in a system, are all tools to improve the DSI system design to promote better removal performance. Tools such as computational fluid dynamic (CFD) modelling can also help to ensure optimisation of lance design and positioning, as well as identify any trouble areas within the flue gas path that may not be adequately mixed with the sorbent stream. In addition, baghouse particulate control devices provide added gas-solid contact over an electrostatic precipitator and therefore typically will have improved performance.

In Figure 3, a case study demonstrating the difference in SO_2 removal performance for two injection locations can be observed. In this trial, testing also included evaluation of the raw mill, when it was in operation and when it was down. In this specific trial, the removal performance was improved when injecting at the baghouse inlet, as compared to the ID fan outlet, which appeared counter-intuitive given the lower residence time at the baghouse inlet location. This may not always be the case, which exemplifies the importance of doing testing prior to designing and installing a permanent DSI system. In this example the performance of this injection location may be attributed to additional mixing opportunities due to some site specific process configurations as well as some reduction in particulate loading, as compared to the ID fan outlet condition.

To further illustrate the importance of upfront testing and evaluating each system on a case-by-case basis, Figure 4 shows that unlike the system configuration for the cement plant in Figure 3 the ID fan injection location was more efficient than the baghouse inlet injection location.

Site specific conditions: flue gas properties and operating conditions

The key flue gas properties of importance are the concentrations of acid gas species and moisture. Figure 3 compares the relative performance of the raw mill on versus the raw mill off. It can be seen that the raw mill off condition provided better removal than when the raw mill was on (i.e. lower mass ratio required to achieve the same SO_2 removal efficiency). During the raw mill off condition the flue gas is bypassed around the raw mill; therefore a lower baseline SO_2 concentration is observed compared to the raw mill on condition. Additionally, when the raw mill is bypassed the quench spray system upstream of the ID fans was turned on for flue gas temperature control, but also increased flue gas moisture content. Figure 3 illustrates that the higher SO_2 concentration and high flue gas moisture content conditions occurring when the raw mill was not operating proved to provide better sorbent performance than when the raw mill was in operation, emphasising the importance of understanding how flue gas properties and operating conditions will directly impact the overall DSI system performance. Additionally, the flue gas temperature at the point of injection is also a critical parameter in determining the effectiveness of DSI technology as the relative performance of the sorbents is directly impacted by the flue gas temperature, and not all sorbents are impacted identically.

Understanding all of the acid gas species present in the flue gas is important in that sorbents react preferentially with the varying acid gas pollutants. In general, calcium hydroxide (hydrated lime) will first capture SO_3, then HCl, followed lastly by SO_2. This means that when evaluating the amount of sorbent required to achieve a given acid gas control level, sorbent utilised to capture the other pollutants must be considered.

Conclusion

Lhoist North America (LNA) has conducted multiple full-scale DSI demonstrations using enhanced hydrated lime products for acid gas control within the cement industry, specifically for SO_2 and/or HCl control, and proved that during short-term parametric testing these products coupled with DSI technology were successful in achieving the desired acid gas abatement over a wide range of process conditions. Based on these demonstrations, LNA concludes the following;

- DSI with hydrated lime sorbents has the ability to achieve high SO_2 and HCl removal efficiencies and the relative performance is dependent on the flue gas properties, including temperature of the flue gas, as well as moisture and the concentration of the acid gas species.
- Enhanced hydrated lime sorbents, such as Sorbacal® SP and Sorbacal® SPS, allow for higher removal efficiencies or lower sorbent usage as compared to standard hydrated limes and are available worldwide, including in the US for upcoming regulations, such as the Portland Cement NESHAP.
- Flue gas moisture appears to be a key factor in sorbent utilisation for SO_2 removal and the relative impacts on performance for SO_2 removal should be studied further.
- Hydrated lime sorbent utilisation for acid gas removal with DSI technology can be optimised by improved sorbent-to-gas contact via in-duct static mixers and/or injection lance design.
- Due to the many differences in site-specific conditions when considering DSI technology, a short-term demonstration test is usually very beneficial in determining the optimal injection location(s), sorbent options for a given removal target, and the range of removal efficiencies that can be expected over the range of site operating conditions tested.