INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

We Protect Hoosiers and Our Environment.

Mitchell E. Daniels Jr.
Governor

Thomas W. Easterly
Commissioner

100 North Senate Avenue
Indianapolis, Indiana 46204
(317) 232-8603
Toll Free (800) 451-6027
www.idem.IN.gov

TO: Interested Parties / Applicant

DATE: November 22, 2011

RE: Micronutrients, A Division of Heritage Technologies, LLC / 097-30945-00417

FROM: Matthew Stuckey, Branch Chief
Permits Branch
Office of Air Quality

Notice of Decision: Approval - Registration

Please be advised that on behalf of the Commissioner of the Department of Environmental Management, I have issued a decision regarding the enclosed matter. Pursuant to IC 4-21.5-3-4(d) this order is effective when it is served. When served by U.S. mail, the order is effective three (3) calendar days from the mailing of this notice pursuant to IC 4-21.5-3-2(e).

If you wish to challenge this decision, IC 4-21.5-3-7 requires that you file a petition for administrative review. This petition may include a request for stay of effectiveness and must be submitted to the Office of Environmental Adjudication, 100 North Senate Avenue, Government Center North, Suite N 501E, Indianapolis, IN 46204, **within eighteen (18) calendar days of the mailing of this notice**. The filing of a petition for administrative review is complete on the earliest of the following dates that apply to the filing:

(1) the date the document is delivered to the Office of Environmental Adjudication (OEA);
(2) the date of the postmark on the envelope containing the document, if the document is mailed to OEA by U.S. mail; or
(3) The date on which the document is deposited with a private carrier, as shown by receipt issued by the carrier, if the document is sent to the OEA by private carrier.

The petition must include facts demonstrating that you are either the applicant, a person aggrieved or adversely affected by the decision or otherwise entitled to review by law. Please identify the permit, decision, or other order for which you seek review by permit number, name of the applicant, location, date of this notice and all of the following:

(1) the name and address of the person making the request;
(2) the interest of the person making the request;
(3) identification of any persons represented by the person making the request;
(4) the reasons, with particularity, for the request;
(5) the issues, with particularity, proposed for considerations at any hearing; and
(6) identification of the terms and conditions which, in the judgment of the person making the request, would be appropriate in the case in question to satisfy the requirements of the law governing documents of the type issued by the Commissioner.

If you have technical questions regarding the enclosed documents, please contact the Office of Air Quality, Permits Branch at (317) 233-0178. Callers from within Indiana may call toll-free at 1-800-451-6027, ext. 3-0178.

Enclosures
FN-REGIS.dot 1/2/08

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REGISTRATION
OFFICE OF AIR QUALITY

Micronutrients, A Division of Heritage Technologies, LLC
1550 Research Way
Indianapolis, Indiana, 46231

Pursuant to 326 IAC 2-5.1 (Construction of New Sources: Registrations) and 326 IAC 2-5.5 (Registrations), (herein known as the Registrant) is hereby authorized to construct and operate subject to the conditions contained herein, the source described in Section A (Source Summary) of this registration.

Registration No. 097-30945-00417	
Issued by: Iryn Calilung, Section Chief Permits Branch Office of Air Quality	Issuance Date: November 22, 2011

SECTION A SOURCE SUMMARY

This registration is based on information requested by the Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ). The information describing the source contained in conditions A.1 and A.2 is descriptive information and does not constitute enforceable conditions. However, the Registrant should be aware that a physical change or a change in the method of operation that may render this descriptive information obsolete or inaccurate may trigger requirements for the Registrant to obtain additional permits pursuant to 326 IAC 2.

A.1 General Information

The Registrant owns and operates a stationary inorganic chemical manufacturing of animal feed supplements source

Source Address:	1550 Research Way, Indianapolis, Indiana, 46231
General Source Phone Number:	(317) 486-5880
SIC Code:	2819 (Industrial Inorganic Chemicals)
County Location:	Marion County
Source Location Status:	Nonattainment for PM 2.5 standard Attainment for all other criteria pollutants
Source Status:	Registration

A.2 Emission Units and Pollution Control Equipment Summary

This stationary source consists of the following emission units and pollution control devices:

(a) One (1) natural gas-fired scotch boiler, identified as HB-1, installed in 1998, with a maximum heat input capacity of 8.4 million Btu per hour (MMBtu/hr), and exhausting to stack B-1.

(b) One (1) natural gas-fired scotch boiler, identified as HB-2, installed in 2002, with a maximum heat input capacity of 12.6 million Btu per hour (MMBtu/hr), and exhausting to stack B-2.

Under the NSPS Small Industrial-Commercial-Institutional Steam Generating Units (40 CFR 60.40b, Subpart Dc) the boiler HB-2 is considered an affected facility.

(c) One (1) natural gas-fired production dryer, identified as PD-1, installed in 1995, with a maximum heat input capacity of 1.5 million Btu per hour (MMBtu/hr), and a maximum process weight rate of 1.15 tons basic copper chloride per hour, using an integral cyclone and an integral dust collector (DC-1) as control, and exhausting to stack D-1.

(d) One (1) natural gas-fired R&D pilot dryer, identified as PD-2, constructed in 2002, with a maximum heat input capacity of 1.0 million Btu per hour (MMBtu/hr), using an integral dust collector as control, and exhausting to stack D-2.

(e) One (1) hydrochloric acid (HCl) receiving tank, identified as T-122, constructed in 1994, with a maximum capacity of 5,137 gallons, using no control device and exhausting indoors.

(f) One (1) hydrochloric acid (HCl) receiving tank, identified as T-122B, constructed in 2005, with a maximum capacity of 10,846 gallons, using no control device and exhausting indoors.

(g) One (1) hydrochloric acid (HCl) process tank, identified as R-156, with a maximum capacity of 4,889 gallons, with emissions from R-156 controlled by one (1) plant HCl scrubber, identified as PS-2, constructed in 2008, and exhausting to stack (S-2).

(h) One (1) hydrochloric acid (HCl) process tank, identified as R-104, with a maximum capacity of 2,760 gallons, with emissions from R-104 controlled by one (1) plant HCl scrubber, identified as PS-2, constructed in 2008, and exhausting to stack (S-2).

(i) One (1) existing material processing system, constructed in (1995), including, but not limited to, pneumatic conveyance process equipment associated with the transfer of material to and within the facility, including liquid tanks, hoppers, shaker screen, silos, conveyors, bucket elevators, and associated pollution control equipment including cyclones and dust collectors. The material processing system includes the following emission units:

(1) One (1) bucket elevator, identified as E-111, constructed in 1995, with a maximum capacity of 3 tons per hour, using an integral dust collector DC-2 as control, and exhausting indoors.

(2) One (1) bucket elevator, identified as E-136, constructed in 2010, with a maximum capacity of 3 tons per hour, using an integral dust collector DC-2 as control, and exhausting indoors.

(3) One (1) bucket elevator, identified as E-137, constructed in 2010, with a maximum capacity of 3 tons per hour, using an integral dust collector DC-2 as control, and exhausting indoors.

(4) One (1) Packaging area, identified as BU-1, constructed in 2010, with a maximum capacity of 3 tons per hour, using an integral dust collector DC-2 as control, and exhausting indoors.

Note: The above emission units in (a) through (i) are located at the Plant. The cyclones and dust collectors are considered integral because they are used for product recovery and separation.

(j) One (1) natural gas-fired BTMP plant steam generator, identified as BB-1, approved in 2011 for construction, with a maximum heat input capacity of 12.6 million British thermal units per hour (MMBtu/hr), and exhausting to stack B-3.

Under the NSPS Small Industrial-Commercial-Institutional Steam Generating Units (40 CFR 60.40b, Subpart Dc) the boiler BB-1 is considered an affected facility.

(k) One (1) BTMP plant dryer system, identified as BD-4, approved in 2011 for construction, with a maximum capacity of 2.5 million British thermal units per hour (MMBtu/hr), using an integral dust collector DC-4 as control, and exhausting to stack D-4.

(l) One (1) BTMP plant dryer system, identified as BD-5, approved in 2011 for construction, with a maximum capacity of 2.5 million British thermal units per hour (MMBtu/hr), using an integral dust collector DC-5 as control, and exhausting to stack D-5.

(m) One (1) BTMP plant dryer system, identified as BD-6, approved in 2011 for construction, with a maximum capacity of 2.5 million British thermal units per hour (MMBtu/hr), using an integral dust collector DC-6 as control, and exhausting to stack D-6.

(n) One (1) BTMP plant dryer system, identified as BD-7, approved in 2011 for construction, with a maximum capacity of 2.5 million British thermal units per hour (MMBtu/hr), using an integral dust collector DC-7 as control, and exhausting to stack D-7.

(o) One (1) BTMP plant dryer system, identified as BD-8, approved in 2011 for construction, with a maximum capacity of 2.5 million British thermal units per hour (MMBtu/hr), using an integral dust collector DC-8 as control, and exhausting to stack D-8.

(p) One (1) hydrochloric acid (HCl) receiving tank, identified as T-211, with a maximum capacity of 19,807 gallons, with emissions from T-211 controlled by one (1) BTMP plant HCl scrubber, identified as BS-4 , approved in 2011 for construction with a maximum capacity of 3,000 CFM and exhausting to stack S-4.

(q) One (1) new material processing system, approved in 2011 for construction, including, but not limited to, pneumatic conveyance process equipment associated with the transfer of material to and within the facility, including liquid tanks, hoppers, storage tanks, conveyors, bagging areas, and associated pollution control equipment including cyclones and dust collectors. The material processing system includes the following emission units:

(1) One (1) Dump hopper, identified as BD-310, approved in 2011 for construction, with a maximum capacity of 1 tons per hour, using integral dust collectors BN-1 and BL-1 as control, and exhausting indoors.

(2) One (1) Dump hopper, identified as BD-320, approved in 2011 for construction, with a maximum capacity of 1 tons per hour, using integral dust collectors BN-1 and BL-1 as control, and exhausting indoors.

(3) One (1) Dump hopper, identified as BD-330, approved in 2011 for construction, with a maximum capacity of 1 tons per hour, using integral dust collectors BN-1 and BL-1 as control, and exhausting indoors.

(4) One (1) Bagging area, identified as BU-2, approved in 2011 for construction, with a maximum capacity of 1 tons per hour, using an integral dust collector BN-2 as control, and exhausting indoors.

(5) One (1) Bagging area, identified as BU-3, approved in 2011 for construction, with a maximum capacity of 1 tons per hour, using an integral dust collector BN-2 as control, and exhausting indoors.

(6) One (1) Bagging area, identified as BU-4, approved in 2011 for construction, with a maximum capacity of 1 tons per hour, using an integral dust collector BN-2 as control, and exhausting indoors.

Note: The above emission units in (j) through (q) are located at the BTMP Plant. The cyclones and dust collectors are considered integral because they are used for product recovery and separation.

SECTION B GENERAL CONDITIONS

B.1 Definitions [326 IAC 2-1.1-1]

Terms in this registration shall have the definition assigned to such terms in the referenced regulation. In the absence of definitions in the referenced regulation, the applicable definitions found in the statutes or regulations (IC 13-11, 326 IAC 1-2 and 326 IAC 2-1.1-1) shall prevail.

B.2 Effective Date of Registration [IC 13-15-5-3]

Pursuant to IC 13-15-5-3, this registration is effective immediately, unless a petition for stay of effectiveness is filed and granted according to IC 13-15-6-3, and may be revoked or modified in accordance with the provisions of IC 13-15-7-1.

B.3 Registration Revocation [326 IAC 2-1.1-9]

Pursuant to 326 IAC 2-1.1-9 (Revocation), this registration to operate may be revoked for any of the following causes:

(a) Violation of any conditions of this registration.

(b) Failure to disclose all the relevant facts, or misrepresentation in obtaining this registration.

(c) Changes in regulatory requirements that mandate either a temporary or permanent reduction of discharge of contaminants. However, the amendment of appropriate sections of this registration shall not require revocation of this registration.

(d) For any cause which establishes in the judgment of IDEM the fact that continuance of this registration is not consistent with purposes of this article.

B.4 Prior Permits Superseded [326 IAC 2-1.1-9.5]

(a) All terms and conditions of permits established prior to Registration No. 097-30945-00417 and issued pursuant to permitting programs approved into the state implementation plan have been either:

(1) incorporated as originally stated,

(2) revised, or

(3) deleted.

(b) All previous registrations and permits are superseded by this registration.

B.5 Annual Notification [326 IAC 2-5.1-2(f)(3)] [326 IAC 2-5.5-4(a)(3)]

Pursuant to 326 IAC 2-5.1-2(f)(3) and 326 IAC 2-5.5-4(a)(3):

(a) An annual notification shall be submitted by an authorized individual to the Office of Air Quality stating whether or not the source is in operation and in compliance with the terms and conditions contained in this registration.

(b) The annual notice shall be submitted in the format attached no later than March 1 of each year to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, IN 46204-2251

(c) The notification shall be considered timely if the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or before the date it is due. If the document is submitted by any other means, it shall be considered timely if received by IDEM, OAQ on or before the date it is due.

B.6 Source Modification Requirement [326 IAC 2-5.5-6(a)]

Pursuant to 326 IAC 2-5.5-6(a), an application or notification shall be submitted in accordance with 326 IAC 2 to the Office of Air Quality (OAQ) if the source proposes to construct new emission units, modify existing emission units, or otherwise modify the source.

B.7 Registrations [326 IAC 2-5.1-2(i)]

Pursuant to 326 IAC 2-5.1-2(i), this registration does not limit the source's potential to emit.

B.8 Preventive Maintenance Plan [326 IAC 1-6-3]

(a) If required by specific condition(s) in Section D of this registration, the Registrant shall prepare and maintain Preventive Maintenance Plans (PMPs) no later than ninety (90) days after issuance of this registration or ninety (90) days after initial start-up, whichever is later, including the following information on each facility:

(1) Identification of the individual(s) responsible for inspecting, maintaining, and repairing emission control devices;

(2) A description of the items or conditions that will be inspected and the inspection schedule for said items or conditions; and

(3) Identification and quantification of the replacement parts that will be maintained in inventory for quick replacement.

If, due to circumstances beyond the Registrant’s control, the PMPs cannot be prepared and maintained within the above time frame, the Registrant may extend the date an additional ninety (90) days provided the Registrant notifies:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

The Registrant shall implement the PMPs.

(b) A copy of the PMPs shall be submitted to IDEM, OAQ upon request and within a reasonable time, and shall be subject to review and approval by IDEM, OAQ. IDEM, OAQ may require the Registrant to revise its PMPs whenever lack of proper maintenance causes or is the primary contributor to an exceedance of any limitation on emissions.

(c) To the extent the Registrant is required by 40 CFR Part 60 or 40 CFR Part 63 to have an Operation Maintenance, and Monitoring (OMM) Plan for a unit, such OMM Plan is deemed to satisfy the PMP requirements of 326 IAC 1-6-3 for that unit.

SECTION C SOURCE OPERATION CONDITIONS

Entire Source

Emission Limitations and Standards [326 IAC 2-5.1-2(g)] [326 IAC 2-5.5-4(b)]

C.1 Opacity [326 IAC 5-1]

Pursuant to 326 IAC 5-1-2 (Opacity Limitations), except as provided in 326 IAC 5-1-3 (Temporary Alternative Opacity Limitations), opacity shall meet the following, unless otherwise stated in this registration:

(a) Opacity shall not exceed an average of thirty percent (30%) in any one (1) six (6) minute averaging period as determined in 326 IAC 5-1-4.

(b) Opacity shall not exceed sixty percent (60%) for more than a cumulative total of fifteen (15) minutes (sixty (60) readings as measured according to 40 CFR 60, Appendix A, Method 9 or fifteen (15) one (1) minute nonoverlapping integrated averages for a continuous opacity monitor) in a six (6) hour period.

C.2 Fugitive Dust Emissions [326 IAC 6-4]

The Registrant shall not allow fugitive dust to escape beyond the property line or boundaries of the property, right-of-way, or easement on which the source is located, in a manner that would violate 326 IAC 6-4 (Fugitive Dust Emissions).

SECTION D.1 OPERATION CONDITIONS

Facility Description [326 IAC 2-5.1-2(f)(2)] [326 IAC 2-5.5-4(a)(2)]:

(a) One (1) natural gas-fired scotch boiler, identified as HB-1, installed in 1998, with a maximum heat input capacity of 8.4 million Btu per hour (MMBtu/hr), and exhausting to stack B-1.

(b) One (1) natural gas-fired scotch boiler, identified as HB-2, installed in 2002, with a maximum heat input capacity of 12.6 million Btu per hour (MMBtu/hr), and exhausting to stack B-2.

Under the NSPS Small Industrial-Commercial-Institutional Steam Generating Units (40 CFR 60.40b, Subpart Dc) the boiler HB-2 is considered an affected facility.

Note: The above emission units in (a) and (b) are located at the Plant.

(j) One (1) natural gas-fired BTMP plant steam generator, identified as BB-1, approved in 2011 for construction, with a maximum heat input capacity of 12.6 million British thermal units per hour (MMBtu/hr), and exhausting to stack B-3.

Under the NSPS Small Industrial-Commercial-Institutional Steam Generating Units (40 CFR 60.40b, Subpart Dc) the boiler BB-1 is considered an affected facility.

Note: The above emission unit (j) is located at the BTMP Plant.

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-5.1-2(f)(1)] [326 IAC 2-5.5-4(a)(1)]

D.1.1 Particulate Emissions [326 IAC 6-2-4]

(a) Pursuant to 326 IAC 6-2-4 (Particulate Emission Limitations for Sources of Indirect Heating), particulate emissions from the boiler, identified HB-1, shall be limited to 0.6 pounds per MMBtu heat input.

(b) Pursuant to 326 IAC 6-2-4 (Particulate Emission Limitations for Sources of Indirect Heating), particulate emissions from the boiler, identified HB-2, shall be limited to 0.494 pounds per MMBtu heat input.

This limitation was computed using the following equation:

$$Pt = 1.09/Q^{0.26}$$

where:

Pt = Pounds of particulate matter emitted per million British thermal units (lb/MMBtu) heat input

Q = Total source maximum operating capacity rating in million British thermal units per hour (MMBtu/hr) heat input. The maximum operating capacity rating is defined as the maximum capacity at which the facility is operated or the nameplate capacity, whichever is specified in the facility's permit application, except when some lower capacity is contained in the facility's operation permit; in which case, the capacity specified in the operation permit shall be used. (Q = 21.0 (8.4 + 12.6) million British thermal units per hour)

(c) Pursuant to 326 IAC 6-2-4 (Particulate Emission Limitations for Sources of Indirect Heating), particulate emissions from the boiler, identified BB-1, shall be limited to 0.437 pounds per MMBtu heat input.

This limitation was computed using the following equation:

$$Pt = 1.09/Q^{0.26}$$

where:

Pt = Pounds of particulate matter emitted per million British thermal units (lb/MMBtu) heat input

Q = Total source maximum operating capacity rating in million British thermal units per hour (MMBtu/hr) heat input. The maximum operating capacity rating is defined as the maximum capacity at which the facility is operated or the nameplate capacity, whichever is specified in the facility's permit application, except when some lower capacity is contained in the facility's operation permit; in which case, the capacity specified in the operation permit shall be used. (Q = 33.6 (8.4 + 12.6 + 12.6) million British thermal units per hour)

D.1.2 Preventive Maintenance Plan [326 IAC 1-6-3]

A Preventive Maintenance Plan is required for this facility and its control device. Section B - Preventive Maintenance Plan contains the Registrant's obligation with regard to the preventive maintenance plan required by this condition.

SECTION D.2 OPERATION CONDITIONS

Facility Description [326 IAC 2-5.1-2(f)(2)] [326 IAC 2-5.5-4(a)(2)]:

(c) One (1) natural gas-fired production dryer, identified as PD-1, installed in 1995, with a maximum heat input capacity of 1.5 million Btu per hour (MMBtu/hr), and a maximum process weight rate of 1.15 tons basic copper chloride per hour, using an integral cyclone and an integral dust collector (DC-1) as control, and exhausting to stack D-1.

Note: The above emission unit in (c) is located at the Plant. The cyclones and dust collectors are considered integral because they are used for product recovery and separation.

(k) One (1) BTMP plant dryer system, identified as BD-4, approved in 2011 for construction, with a maximum capacity of 2.5 million British thermal units per hour (MMBtu/hr), using an integral dust collector DC-4 as control, and exhausting to stack D-4.

(l) One (1) BTMP plant dryer system, identified as BD-5, approved in 2011 for construction, with a maximum capacity of 2.5 million British thermal units per hour (MMBtu/hr), using an integral dust collector DC-5 as control, and exhausting to stack D-5.

(m) One (1) BTMP plant dryer system, identified as BD-6, approved in 2011 for construction, with a maximum capacity of 2.5 million British thermal units per hour (MMBtu/hr), using an integral dust collector DC-6 as control, and exhausting to stack D-6.

(n) One (1) BTMP plant dryer system, identified as BD-7, approved in 2011 for construction, with a maximum capacity of 2.5 million British thermal units per hour (MMBtu/hr), using an integral dust collector DC-7 as control, and exhausting to stack D-7.

(o) One (1) BTMP plant dryer system, identified as BD-8, approved in 2011 for construction, with a maximum capacity of 2.5 million British thermal units per hour (MMBtu/hr), using an integral dust collector DC-8 as control, and exhausting to stack D-8.

Note: The above emission units (k) through (o) are located at the BTMP Plant. The cyclones and dust collectors are considered integral because they are used for product recovery and separation.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-5.1-2(f)(1)] [326 IAC 2-5.5-4(a)(1)]

D.2.1 Particulate Emissions Limitations [326 IAC 6-3-2]

Pursuant to 326 IAC 6-3-2, the particulate emissions from each of the following processes shall not exceed the pound per hour limitations specified in the following table:

Emission unit ID	Control ID	Maximum Process Weight (tons/hour) for each unit	326 IAC 6-3 Limit (lbs/hr) for each unit
PD-1	DC-1	1.15	4.50
BD-4	DC-4	1.15	4.50
BD-5	DC-5	1.15	4.50
BD-6	DC-6	1.15	4.50
BD-7	DC-7	1.15	4.50
BD-8	DC-8	1.15	4.50

The particulate emissions limitations from the above table shall be calculated using the following equation:

Interpolation of the data for the process weight rate up to sixty thousand (60,000) pounds per hour shall be accomplished by use of the equation:

$E = 4.10 P^{0.67}$ where E = rate of emission in pounds per hour; and P = process weight rate in tons per hour

D.2.2 Preventive Maintenance Plan [326 IAC 1-6-3]

A Preventive Maintenance Plan is required for this facility and its control device. Section B - Preventive Maintenance Plan contains the Registrant's obligation with regard to the preventive maintenance plan required by this condition.

Compliance Determination Requirements [326 IAC 2-5.1-2(g)] [326 IAC 2-5.5-4(b)]

D.2.3 Particulate Control

(a) In order to comply with Condition D.2.1, the integral control devices, identified as DC-1, and DC-4 through DC-8, for particulate control shall be in operation and control emissions from the drying operations at all times that the drying operations are in operation.

(b) In the event that bag failure is observed in a multi-compartment baghouse, if operations will continue for ten (10) days or more after the failure is observed before the failed units will be repaired or replaced, the Permittee shall promptly notify the IDEM, OAQ of the expected date the failed units will be repaired or replaced. The notification shall also include the status of the applicable compliance monitoring parameters with respect to normal, and the results of any response actions taken up to the time of notification.

Compliance Monitoring Requirements [326 IAC 2-5.1-2(g)] [326 IAC 2-5.5-4(b)]

D.2.4 Broken or Failed Bag Detection

In the event that bag failure has been observed:

(a) For a single compartment baghouses controlling emissions from a process operated continuously, a failed unit and the associated process shall be shut down immediately until the failed unit has been repaired or replaced.

(b) For a single compartment baghouse controlling emissions from a batch process, the feed to the process shall be shut down immediately until the failed unit has been repaired or replaced. The emissions unit shall be shut down no later than the completion of the processing of the material in the emissions unit.

Bag failure can be indicated by a significant drop in the baghouse's pressure reading with abnormal visible emissions, by an opacity violation, or by other means such as gas temperature, flow rate, air infiltration, leaks, dust traces or triboflows.

SECTION E.1 OPERATION CONDITIONS

Facility Description [326 IAC 2-5.1-2(f)(2)] [326 IAC 2-5.5-4(a)(2)]:

(a) One (1) natural gas-fired scotch boiler, identified as HB-1, installed in 1998, with a maximum heat input capacity of 8.4 million Btu per hour (MMBtu/hr), and exhausting to stack B-1.

(b) One (1) natural gas-fired scotch boiler, identified as HB-2, installed in 2002, with a maximum heat input capacity of 12.6 million Btu per hour (MMBtu/hr), and exhausting to stack B-2.

Under the NSPS Small Industrial-Commercial-Institutional Steam Generating Units (40 CFR 60.40b, Subpart Dc) the boiler HB-2 is considered an affected facility.

Note: The above emission units in (a) and (b) are located at the Plant.

(j) One (1) natural gas-fired BTMP plant steam generator, identified as BB-1, approved in 2011 for construction, with a maximum heat input capacity of 12.6 million British thermal units per hour (MMBtu/hr), and exhausting to stack B-3.

Under the NSPS Small Industrial-Commercial-Institutional Steam Generating Units (40 CFR 60.40b, Subpart Dc) the boiler BB-1 is considered an affected facility.

Note: The above emission unit (j) is located at the BTMP Plant.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

E.1.1 General Provisions Relating to New Source Performance Standards (NSPS) for Small Industrial-Commercial-Institutional Steam Generating Units [40 CFR Part 60, Subpart A] [326 IAC 12-1]

(a) Pursuant to 40 CFR 60.1, the Registrant shall comply with the provisions of 40 CFR Part 60, Subpart A - General Provisions, which are incorporated by reference in 326 IAC 12-1, except when otherwise specified in 40 CFR Part 60, Subpart Dc (included as Attachment A of this permit).

(b) Pursuant to 40 CFR 60.19, the Permittee shall submit all required notifications and reports to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

E.1.2 New Source Performance Standards (NSPS) for Small Industrial-Commercial-Institutional Steam Generating Units [40 CFR Part 60, Subpart Dc] [326 IAC 12-1]

The Registrant, which engages in inorganic chemical manufacturing of animal feed supplements, shall comply with the following provisions of 40 CFR Part 60, Subpart Dc (included as Attachment A of this permit):

(1) 40 CFR 60.40c(a)
(2) 40 CFR 60.41c
(3) 40 CFR 60.48c (a), (g)(1)-(3), and (i)

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE AND ENFORCEMENT BRANCH

REGISTRATION
ANNUAL NOTIFICATION

This form should be used to comply with the notification requirements under 326 IAC 2-5.1-2(f)(3) and 326 IAC 2-5.5-4(a)(3).

Company Name:	Micronutrients, A Division of Heritage Technologies, LLC
Address:	1550 Research Way
City:	Indianapolis, Indiana, 46231
Phone Number:	(317) 486-5880
Registration No.:	097-30945-00417

I hereby certify that Micronutrients, A Division of Heritage Technologies, LLC is:

☐ still in operation.

☐ no longer in operation.

I hereby certify that Micronutrients, A Division of Heritage Technologies, LLC is:

☐ in compliance with the requirements of Registration No. 097-30945-00417.

☐ not in compliance with the requirements of Registration No. 097-30945-00417.

Authorized Individual (typed):
Title:
Signature:
Phone Number:
Date:

If there are any conditions or requirements for which the source is not in compliance, provide a narrative description of how the source did or will achieve compliance and the date compliance was, or will be achieved.

Noncompliance:

Attachment A
to Registration No. 097-30945-00417

Micronutrients, A Division of Heritage Technologies, LLC
1550 Research Way, Indianapolis, Indiana, 46231

Subpart Dc—Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

Source: 72 FR 32759, June 13, 2007, unless otherwise noted.

§ 60.40c Applicability and delegation of authority.

(a) Except as provided in paragraphs (d), (e), (f), and (g) of this section, the affected facility to which this subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/hr)) or less, but greater than or equal to 2.9 MW (10 MMBtu/hr).

(b) In delegating implementation and enforcement authority to a State under section 111(c) of the Clean Air Act, §60.48c(a)(4) shall be retained by the Administrator and not transferred to a State.

(c) Steam generating units that meet the applicability requirements in paragraph (a) of this section are not subject to the sulfur dioxide (SO_2) or particulate matter (PM) emission limits, performance testing requirements, or monitoring requirements under this subpart (§§60.42c, 60.43c, 60.44c, 60.45c, 60.46c, or 60.47c) during periods of combustion research, as defined in §60.41c.

(d) Any temporary change to an existing steam generating unit for the purpose of conducting combustion research is not considered a modification under §60.14.

(e) Heat recovery steam generators that are associated with combined cycle gas turbines and meet the applicability requirements of subpart KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other heat recovery steam generators that are capable of combusting more than or equal to 2.9 MW (10 MMBtu/hr) heat input of fossil fuel but less than or equal to 29 MW (100 MMBtu/hr) heat input of fossil fuel. If the heat recovery steam generator is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The gas turbine emissions are subject to subpart GG or KKKK, as applicable, of this part).

(f) Any facility covered by subpart AAAA of this part is not subject by this subpart.

(g) Any facility covered by an EPA approved State or Federal section 111(d)/129 plan implementing subpart BBBB of this part is not subject by this subpart.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5090, Jan. 28, 2009]

§ 60.41c Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act and in subpart A of this part.

Annual capacity factor means the ratio between the actual heat input to a steam generating unit from an individual fuel or combination of fuels during a period of 12 consecutive calendar months and the potential heat input to the steam generating unit from all fuels had the steam generating unit been operated for

8,760 hours during that 12-month period at the maximum design heat input capacity. In the case of steam generating units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility during a period of 12 consecutive calendar months.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17), coal refuse, and petroleum coke. Coal-derived synthetic fuels derived from coal for the purposes of creating useful heat, including but not limited to solvent refined coal, gasified coal not meeting the definition of natural gas, coal-oil mixtures, and coal-water mixtures, are also included in this definition for the purposes of this subpart.

Coal refuse means any by-product of coal mining or coal cleaning operations with an ash content greater than 50 percent (by weight) and a heating value less than 13,900 kilojoules per kilogram (kJ/kg) (6,000 Btu per pound (Btu/lb) on a dry basis.

Cogeneration steam generating unit means a steam generating unit that simultaneously produces both electrical (or mechanical) and thermal energy from the same primary energy source.

Combined cycle system means a system in which a separate source (such as a stationary gas turbine, internal combustion engine, or kiln) provides exhaust gas to a steam generating unit.

Combustion research means the experimental firing of any fuel or combination of fuels in a steam generating unit for the purpose of conducting research and development of more efficient combustion or more effective prevention or control of air pollutant emissions from combustion, provided that, during these periods of research and development, the heat generated is not used for any purpose other than preheating combustion air for use by that steam generating unit (*i.e.* , the heat generated is released to the atmosphere without being used for space heating, process heating, driving pumps, preheating combustion air for other units, generating electricity, or any other purpose).

Conventional technology means wet flue gas desulfurization technology, dry flue gas desulfurization technology, atmospheric fluidized bed combustion technology, and oil hydrodesulfurization technology.

Distillate oil means fuel oil that complies with the specifications for fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D396 (incorporated by reference, see §60.17) or diesel fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see §60.17).

Dry flue gas desulfurization technology means a SO_2control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline reagent and water, whether introduced separately or as a premixed slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline reagents used in dry flue gas desulfurization systems include, but are not limited to, lime and sodium compounds.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source (such as a stationary gas turbine, internal combustion engine, kiln, etc.) to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a steam generating unit.

Emerging technology means any SO_2 control system that is not defined as a conventional technology under this section, and for which the owner or operator of the affected facility has received approval from the Administrator to operate as an emerging technology under §60.48c(a)(4).

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 51.24.

Fluidized bed combustion technology means a device wherein fuel is distributed onto a bed (or series of beds) of limestone aggregate (or other sorbent materials) for combustion; and these materials are forced upward in the device by the flow of combustion air and the gaseous products of combustion. Fluidized bed combustion technology includes, but is not limited to, bubbling bed units and circulating bed units.

Fuel pretreatment means a process that removes a portion of the sulfur in a fuel before combustion of the fuel in a steam generating unit.

Heat input means heat derived from combustion of fuel in a steam generating unit and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust gases from other sources (such as stationary gas turbines, internal combustion engines, and kilns).

Heat transfer medium means any material that is used to transfer heat from one point to another point.

Maximum design heat input capacity means the ability of a steam generating unit to combust a stated maximum amount of fuel (or combination of fuels) on a steady state basis as determined by the physical design and characteristics of the steam generating unit.

Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) Liquefied petroleum (LP) gas, as defined by the American Society for Testing and Materials in ASTM D1835 (incorporated by reference, see §60.17); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 34 and 43 megajoules (MJ) per dry standard cubic meter (910 and 1,150 Btu per dry standard cubic foot).

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Oil means crude oil or petroleum, or a liquid fuel derived from crude oil or petroleum, including distillate oil and residual oil.

Potential sulfur dioxide emission rate means the theoretical SO_2 emissions (nanograms per joule (ng/J) or lb/MMBtu heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems.

Process heater means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst.

Residual oil means crude oil, fuel oil that does not comply with the specifications under the definition of distillate oil, and all fuel oil numbers 4, 5, and 6, as defined by the American Society for Testing and Materials in ASTM D396 (incorporated by reference, see §60.17).

Steam generating unit means a device that combusts any fuel and produces steam or heats water or heats any heat transfer medium. This term includes any duct burner that combusts fuel and is part of a combined cycle system. This term does not include process heaters as defined in this subpart.

Steam generating unit operating day means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

Wet flue gas desulfurization technology means an SO_2control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a liquid material. This definition includes devices where the liquid material is subsequently converted to another form. Alkaline reagents used in wet flue gas desulfurization systems include, but are not limited to, lime, limestone, and sodium compounds.

Wet scrubber system means any emission control device that mixes an aqueous stream or slurry with the exhaust gases from a steam generating unit to control emissions of PM or SO_2.

Wood means wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including but not limited to sawdust, sanderdust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5090, Jan. 28, 2009]

§ 60.42c Standard for sulfur dioxide (SO_2).

(a) Except as provided in paragraphs (b), (c), and (e) of this section, on and after the date on which the performance test is completed or required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that combusts only coal shall neither: cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO_2emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2in excess of 520 ng/J (1.2 lb/MMBtu) heat input. If coal is combusted with other fuels, the affected facility shall neither: cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO_2emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2in excess of the emission limit is determined pursuant to paragraph (e)(2) of this section.

(b) Except as provided in paragraphs (c) and (e) of this section, on and after the date on which the performance test is completed or required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that:

(1) Combusts only coal refuse alone in a fluidized bed combustion steam generating unit shall neither:

(i) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 20 percent (0.20) of the potential SO_2emission rate (80 percent reduction); nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2in excess of SO_2in excess of 520 ng/J (1.2 lb/MMBtu) heat input. If coal is fired with coal refuse, the affected facility subject to paragraph (a) of this section. If oil or any other fuel (except coal) is fired with coal refuse, the affected facility is subject to the 87 ng/J (0.20 lb/MMBtu) heat input SO_2emissions limit or the 90 percent SO_2reduction requirement specified in paragraph (a) of this section and the emission limit is determined pursuant to paragraph (e)(2) of this section.

(2) Combusts only coal and that uses an emerging technology for the control of SO_2emissions shall neither:

(i) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2in excess of 50 percent (0.50) of the potential SO_2emission rate (50 percent reduction); nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2in excess of 260 ng/J (0.60 lb/MMBtu) heat input. If coal is combusted with other fuels, the affected facility is subject to the 50 percent SO_2reduction requirement specified in this paragraph and the emission limit determined pursuant to paragraph (e)(2) of this section.

(c) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, alone or in combination with any other fuel, and is listed in paragraphs (c)(1), (2), (3), or (4) of this section shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2in excess of the emission limit determined pursuant to paragraph (e)(2) of this section. Percent reduction requirements are not applicable to affected facilities under paragraphs (c)(1), (2), (3), or (4).

(1) Affected facilities that have a heat input capacity of 22 MW (75 MMBtu/hr) or less.

(2) Affected facilities that have an annual capacity for coal of 55 percent (0.55) or less and are subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for coal of 55 percent (0.55) or less.

(3) Affected facilities located in a noncontinental area.

(4) Affected facilities that combust coal in a duct burner as part of a combined cycle system where 30 percent (0.30) or less of the heat entering the steam generating unit is from combustion of coal in the duct burner and 70 percent (0.70) or more of the heat entering the steam generating unit is from exhaust gases entering the duct burner.

(d) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts oil shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2in excess of 215 ng/J (0.50 lb/MMBtu) heat input; or, as an alternative, no owner or operator of an affected facility that combusts oil shall combust oil in the affected facility that contains greater than 0.5 weight percent sulfur. The percent reduction requirements are not applicable to affected facilities under this paragraph.

(e) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, or coal and oil with any other fuel shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of the following:

(1) The percent of potential SO_2 emission rate or numerical SO_2 emission rate required under paragraph (a) or (b)(2) of this section, as applicable, for any affected facility that

(i) Combusts coal in combination with any other fuel;

(ii) Has a heat input capacity greater than 22 MW (75 MMBtu/hr); and

(iii) Has an annual capacity factor for coal greater than 55 percent (0.55); and

(2) The emission limit determined according to the following formula for any affected facility that combusts coal, oil, or coal and oil with any other fuel:

$$E_s = \frac{(K_a H_a + K_b H_b + K_c H_c)}{(H_a + H_b + H_c)}$$

Where:

E_s = SO_2 emission limit, expressed in ng/J or lb/MMBtu heat input;

K_a = 520 ng/J (1.2 lb/MMBtu);

K_b = 260 ng/J (0.60 lb/MMBtu);

K_c = 215 ng/J (0.50 lb/MMBtu);

H_a = Heat input from the combustion of coal, except coal combusted in an affected facility subject to paragraph (b)(2) of this section, in Joules (J) [MMBtu];

H_b = Heat input from the combustion of coal in an affected facility subject to paragraph (b)(2) of this section, in J (MMBtu); and

H_c = Heat input from the combustion of oil, in J (MMBtu).

(f) Reduction in the potential SO_2 emission rate through fuel pretreatment is not credited toward the percent reduction requirement under paragraph (b)(2) of this section unless:

(1) Fuel pretreatment results in a 50 percent (0.50) or greater reduction in the potential SO_2 emission rate; and

(2) Emissions from the pretreated fuel (without either combustion or post-combustion SO_2 control) are equal to or less than the emission limits specified under paragraph (b)(2) of this section.

(g) Except as provided in paragraph (h) of this section, compliance with the percent reduction requirements, fuel oil sulfur limits, and emission limits of this section shall be determined on a 30-day rolling average basis.

(h) For affected facilities listed under paragraphs (h)(1), (2), or (3) of this section, compliance with the emission limits or fuel oil sulfur limits under this section may be determined based on a certification from the fuel supplier, as described under §60.48c(f), as applicable.

(1) Distillate oil-fired affected facilities with heat input capacities between 2.9 and 29 MW (10 and 100 MMBtu/hr).

(2) Residual oil-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/hr).

(3) Coal-fired facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/hr).

(i) The SO_2 emission limits, fuel oil sulfur limits, and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction.

(j) For affected facilities located in noncontinental areas and affected facilities complying with the percent reduction standard, only the heat input supplied to the affected facility from the combustion of coal and oil is counted under this section. No credit is provided for the heat input to the affected facility from wood or other fuels or for heat derived from exhaust gases from other sources, such as stationary gas turbines, internal combustion engines, and kilns.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5090, Jan. 28, 2009]

§ 60.43c   Standard for particulate matter (PM).

(a) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal or combusts mixtures of coal with other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/hr) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 22 ng/J (0.051 lb/MMBtu) heat input if the affected facility combusts only coal, or combusts coal with other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

(2) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility combusts coal with other fuels, has an annual capacity factor for the other fuels greater than 10 percent (0.10), and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor greater than 10 percent (0.10) for fuels other than coal.

(b) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts wood or combusts mixtures of wood with other fuels (except coal) and has a heat input capacity of 8.7 MW (30 MMBtu/hr) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emissions limits:

(1) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility has an annual capacity factor for wood greater than 30 percent (0.30); or

(2) 130 ng/J (0.30 lb/MMBtu) heat input if the affected facility has an annual capacity factor for wood of 30 percent (0.30) or less and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for wood of 30 percent (0.30) or less.

(c) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that can combust coal, wood, or oil and has a heat input capacity of 8.7 MW (30 MMBtu/hr) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. Owners and operators of an affected facility that elect to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart and are subject to a federally enforceable PM limit of 0.030 lb/MMBtu or less are exempt from the opacity standard specified in this paragraph.

(d) The PM and opacity standards under this section apply at all times, except during periods of startup, shutdown, or malfunction.

(e)(1) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/hr) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 13 ng/J (0.030 lb/MMBtu) heat input, except as provided in paragraphs (e)(2), (e)(3), and (e)(4) of this section.

(2) As an alternative to meeting the requirements of paragraph (e)(1) of this section, the owner or operator of an affected facility for which modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of both:

(i) 22 ng/J (0.051 lb/MMBtu) heat input derived from the combustion of coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels; and

(ii) 0.2 percent of the combustion concentration (99.8 percent reduction) when combusting coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels.

(3) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a heat input capacity of 8.7 MW (30 MMBtu/hr) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

(4) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, an owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.50 weight percent sulfur or a mixture of 0.50 weight percent sulfur oil with other

fuels not subject to a PM standard under §60.43c and not using a post-combustion technology (except a wet scrubber) to reduce PM or SO_2 emissions is not subject to the PM limit in this section.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009]

§ 60.44c Compliance and performance test methods and procedures for sulfur dioxide.

(a) Except as provided in paragraphs (g) and (h) of this section and §60.8(b), performance tests required under §60.8 shall be conducted following the procedures specified in paragraphs (b), (c), (d), (e), and (f) of this section, as applicable. Section 60.8(f) does not apply to this section. The 30-day notice required in §60.8(d) applies only to the initial performance test unless otherwise specified by the Administrator.

(b) The initial performance test required under §60.8 shall be conducted over 30 consecutive operating days of the steam generating unit. Compliance with the percent reduction requirements and SO_2 emission limits under §60.42c shall be determined using a 30-day average. The first operating day included in the initial performance test shall be scheduled within 30 days after achieving the maximum production rate at which the affect facility will be operated, but not later than 180 days after the initial startup of the facility. The steam generating unit load during the 30-day period does not have to be the maximum design heat input capacity, but must be representative of future operating conditions.

(c) After the initial performance test required under paragraph (b) of this section and §60.8, compliance with the percent reduction requirements and SO_2 emission limits under §60.42c is based on the average percent reduction and the average SO_2 emission rates for 30 consecutive steam generating unit operating days. A separate performance test is completed at the end of each steam generating unit operating day, and a new 30-day average percent reduction and SO_2 emission rate are calculated to show compliance with the standard.

(d) If only coal, only oil, or a mixture of coal and oil is combusted in an affected facility, the procedures in Method 19 of appendix A of this part are used to determine the hourly SO_2 emission rate (E_{ho}) and the 30-day average SO_2 emission rate (E_{ao}). The hourly averages used to compute the 30-day averages are obtained from the CEMS. Method 19 of appendix A of this part shall be used to calculate E_{ao} when using daily fuel sampling or Method 6B of appendix A of this part.

(e) If coal, oil, or coal and oil are combusted with other fuels:

(1) An adjusted E_{ho} ($E_{ho}o$) is used in Equation 19–19 of Method 19 of appendix A of this part to compute the adjusted E_{ao} ($E_{ao}o$). The $E_{ho}o$ is computed using the following formula:

$$E_{ho}o = \frac{E_{ho} - E_w(1 - X_1)}{X_1}$$

Where:

$E_{ho}o$ = Adjusted E_{ho}, ng/J (lb/MMBtu);

E_{ho} = Hourly SO_2 emission rate, ng/J (lb/MMBtu);

E_w = SO_2 concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 9 of appendix A of this part, ng/J (lb/MMBtu). The value

E_w for each fuel lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure E_w if the owner or operator elects to assume E_w = 0.

X_k = Fraction of the total heat input from fuel combustion derived from coal and oil, as determined by applicable procedures in Method 19 of appendix A of this part.

(2) The owner or operator of an affected facility that qualifies under the provisions of §60.42c(c) or (d) (where percent reduction is not required) does not have to measure the parameters E_w or X_k if the owner or operator of the affected facility elects to measure emission rates of the coal or oil using the fuel sampling and analysis procedures under Method 19 of appendix A of this part.

(f) Affected facilities subject to the percent reduction requirements under §60.42c(a) or (b) shall determine compliance with the SO_2 emission limits under §60.42c pursuant to paragraphs (d) or (e) of this section, and shall determine compliance with the percent reduction requirements using the following procedures:

(1) If only coal is combusted, the percent of potential SO_2 emission rate is computed using the following formula:

$$\%P_s = 100\left(1 - \frac{\%R_g}{100}\right)\left(1 - \frac{\%R_f}{100}\right)$$

Where:

$\%P_s$ = Potential SO_2 emission rate, in percent;

$\%R_g$ = SO_2 removal efficiency of the control device as determined by Method 19 of appendix A of this part, in percent; and

$\%R_f$ = SO_2 removal efficiency of fuel pretreatment as determined by Method 19 of appendix A of this part, in percent.

(2) If coal, oil, or coal and oil are combusted with other fuels, the same procedures required in paragraph (f)(1) of this section are used, except as provided for in the following:

(i) To compute the $\%P_s$, an adjusted $\%R_g$ ($\%R_g$o) is computed from E_{ao}o from paragraph (e)(1) of this section and an adjusted average SO_2 inlet rate (E_{ai}o) using the following formula:

$$\%R_g^o = 100\left(1 - \frac{E_{ao}^o}{E_{ai}^o}\right)$$

Where:

$\%R_g$o = Adjusted $\%R_g$, in percent;

E_{ao}o = Adjusted E_{ao}, ng/J (lb/MMBtu); and

E_{ai}o = Adjusted average SO_2 inlet rate, ng/J (lb/MMBtu).

(ii) To compute $E_{ai}o$, an adjusted hourly SO_2 inlet rate ($E_{hi}o$) is used. The $E_{hi}o$ is computed using the following formula:

$$E_{hi}o = \frac{E_{hi} - E_w(1 - X_k)}{X_k}$$

Where:

$E_{hi}o$ = Adjusted E_{hi}, ng/J (lb/MMBtu);

E_{hi}= Hourly SO_2 inlet rate, ng/J (lb/MMBtu);

E_w= SO_2 concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 19 of appendix A of this part, ng/J (lb/MMBtu). The value E_w for each fuel lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure E_w if the owner or operator elects to assume E_w= 0; and

X_k= Fraction of the total heat input from fuel combustion derived from coal and oil, as determined by applicable procedures in Method 19 of appendix A of this part.

(g) For oil-fired affected facilities where the owner or operator seeks to demonstrate compliance with the fuel oil sulfur limits under §60.42c based on shipment fuel sampling, the initial performance test shall consist of sampling and analyzing the oil in the initial tank of oil to be fired in the steam generating unit to demonstrate that the oil contains 0.5 weight percent sulfur or less. Thereafter, the owner or operator of the affected facility shall sample the oil in the fuel tank after each new shipment of oil is received, as described under §60.46c(d)(2).

(h) For affected facilities subject to §60.42c(h)(1), (2), or (3) where the owner or operator seeks to demonstrate compliance with the SO_2 standards based on fuel supplier certification, the performance test shall consist of the certification from the fuel supplier, as described in §60.48c(f), as applicable.

(i) The owner or operator of an affected facility seeking to demonstrate compliance with the SO_2 standards under §60.42c(c)(2) shall demonstrate the maximum design heat input capacity of the steam generating unit by operating the steam generating unit at this capacity for 24 hours. This demonstration shall be made during the initial performance test, and a subsequent demonstration may be requested at any other time. If the demonstrated 24-hour average firing rate for the affected facility is less than the maximum design heat input capacity stated by the manufacturer of the affected facility, the demonstrated 24-hour average firing rate shall be used to determine the annual capacity factor for the affected facility; otherwise, the maximum design heat input capacity provided by the manufacturer shall be used.

(j) The owner or operator of an affected facility shall use all valid SO_2 emissions data in calculating $\%P_s$ and E_{ho} under paragraphs (d), (e), or (f) of this section, as applicable, whether or not the minimum emissions data requirements under §60.46c(f) are achieved. All valid emissions data, including valid data collected during periods of startup, shutdown, and malfunction, shall be used in calculating $\%P_s$ or E_{ho} pursuant to paragraphs (d), (e), or (f) of this section, as applicable.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009]

§ 60.45c Compliance and performance test methods and procedures for particulate matter.

(a) The owner or operator of an affected facility subject to the PM and/or opacity standards under §60.43c shall conduct an initial performance test as required under §60.8, and shall conduct subsequent performance tests as requested by the Administrator, to determine compliance with the standards using the following procedures and reference methods, except as specified in paragraph (c) of this section.

(1) Method 1 of appendix A of this part shall be used to select the sampling site and the number of traverse sampling points.

(2) Method 3A or 3B of appendix A–2 of this part shall be used for gas analysis when applying Method 5 or 5B of appendix A–3 of this part or 17 of appendix A–6 of this part.

(3) Method 5, 5B, or 17 of appendix A of this part shall be used to measure the concentration of PM as follows:

(i) Method 5 of appendix A of this part may be used only at affected facilities without wet scrubber systems.

(ii) Method 17 of appendix A of this part may be used at affected facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160 °C (320 °F). The procedures of Sections 8.1 and 11.1 of Method 5B of appendix A of this part may be used in Method 17 of appendix A of this part only if Method 17 of appendix A of this part is used in conjunction with a wet scrubber system. Method 17 of appendix A of this part shall not be used in conjunction with a wet scrubber system if the effluent is saturated or laden with water droplets.

(iii) Method 5B of appendix A of this part may be used in conjunction with a wet scrubber system.

(4) The sampling time for each run shall be at least 120 minutes and the minimum sampling volume shall be 1.7 dry standard cubic meters (dscm) [60 dry standard cubic feet (dscf)] except that smaller sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors.

(5) For Method 5 or 5B of appendix A of this part, the temperature of the sample gas in the probe and filter holder shall be monitored and maintained at 160 ±14 °C (320±25 °F).

(6) For determination of PM emissions, an oxygen (O_2) or carbon dioxide (CO_2) measurement shall be obtained simultaneously with each run of Method 5, 5B, or 17 of appendix A of this part by traversing the duct at the same sampling location.

(7) For each run using Method 5, 5B, or 17 of appendix A of this part, the emission rates expressed in ng/J (lb/MMBtu) heat input shall be determined using:

(i) The O_2 or CO_2 measurements and PM measurements obtained under this section, (ii) The dry basis F factor, and

(iii) The dry basis emission rate calculation procedure contained in Method 19 of appendix A of this part.

(8) Method 9 of appendix A–4 of this part shall be used for determining the opacity of stack emissions.

(b) The owner or operator of an affected facility seeking to demonstrate compliance with the PM standards under §60.43c(b)(2) shall demonstrate the maximum design heat input capacity of the steam generating unit by operating the steam generating unit at this capacity for 24 hours. This demonstration shall be made during the initial performance test, and a subsequent demonstration may be requested at any other time. If the demonstrated 24-hour average firing rate for the affected facility is less than the maximum design heat input capacity stated by the manufacturer of the affected facility, the demonstrated 24-hour average firing rate shall be used to determine the annual capacity factor for the affected facility; otherwise, the maximum design heat input capacity provided by the manufacturer shall be used.

(c) In place of PM testing with Method 5 or 5B of appendix A–3 of this part or Method 17 of appendix A–6 of this part, an owner or operator may elect to install, calibrate, maintain, and operate a CEMS for monitoring PM emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility who elects to continuously monitor PM emissions instead of conducting performance testing using Method 5 or 5B of appendix A–3 of this part or Method 17 of appendix A–6 of this part shall install, calibrate, maintain, and operate a CEMS and shall comply with the requirements specified in paragraphs (c)(1) through (c)(14) of this section.

(1) Notify the Administrator 1 month before starting use of the system.

(2) Notify the Administrator 1 month before stopping use of the system.

(3) The monitor shall be installed, evaluated, and operated in accordance with §60.13 of subpart A of this part.

(4) The initial performance evaluation shall be completed no later than 180 days after the date of initial startup of the affected facility, as specified under §60.8 of subpart A of this part or within 180 days of notification to the Administrator of use of CEMS if the owner or operator was previously determining compliance by Method 5, 5B, or 17 of appendix A of this part performance tests, whichever is later.

(5) The owner or operator of an affected facility shall conduct an initial performance test for PM emissions as required under §60.8 of subpart A of this part. Compliance with the PM emission limit shall be determined by using the CEMS specified in paragraph (d) of this section to measure PM and calculating a 24-hour block arithmetic average emission concentration using EPA Reference Method 19 of appendix A of this part, section 4.1.

(6) Compliance with the PM emission limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emission concentrations using CEMS outlet data.

(7) At a minimum, valid CEMS hourly averages shall be obtained as specified in paragraph (c)(7)(i) of this section for 75 percent of the total operating hours per 30-day rolling average.

(i) At least two data points per hour shall be used to calculate each 1-hour arithmetic average.

(ii) [Reserved]

(8) The 1-hour arithmetic averages required under paragraph (c)(7) of this section shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the boiler operating day daily arithmetic average emission concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under §60.13(e)(2) of subpart A of this part.

(9) All valid CEMS data shall be used in calculating average emission concentrations even if the minimum CEMS data requirements of paragraph (c)(7) of this section are not met.

(10) The CEMS shall be operated according to Performance Specification 11 in appendix B of this part.

(11) During the correlation testing runs of the CEMS required by Performance Specification 11 in appendix B of this part, PM and O_2(or CO_2) data shall be collected concurrently (or within a 30- to 60-minute period) by both the continuous emission monitors and performance tests conducted using the following test methods.

(i) For PM, Method 5 or 5B of appendix A–3 of this part or Method 17 of appendix A–6 of this part shall be used; and

(ii) For O2 (or CO_2), Method 3A or 3B of appendix A–2 of this part, as applicable shall be used.

(12) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 2 in appendix F of this part. Relative Response Audit's must be performed annually and Response Correlation Audits must be performed every 3 years.

(13) When PM emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 of appendix A of this part to provide, as necessary, valid emissions data for a minimum of 75 percent of total operating hours on a 30-day rolling average.

(14) After July 1, 2011, within 90 days after the date of completing each performance evaluation required by paragraph (c)(11) of this section, the owner or operator of the affected facility must either submit the test data to EPA by successfully entering the data electronically into EPA's WebFIRE data base available at *http://cfpub.epa.gov/oarweb/index.cfm?action=fire.main* or mail a copy to: United States Environmental Protection Agency; Energy Strategies Group; 109 TW Alexander DR; Mail Code: D243–01; RTP, NC 27711.

(d) The owner or operator of an affected facility seeking to demonstrate compliance under §60.43c(e)(4) shall follow the applicable procedures under §60.48c(f). For residual oil-fired affected facilities, fuel supplier certifications are only allowed for facilities with heat input capacities between 2.9 and 8.7 MW (10 to 30 MMBtu/hr).

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009; 76 FR 3523, Jan. 20, 2011]

§ 60.46c Emission monitoring for sulfur dioxide.

(a) Except as provided in paragraphs (d) and (e) of this section, the owner or operator of an affected facility subject to the SO_2emission limits under §60.42c shall install, calibrate, maintain, and operate a CEMS for measuring SO_2concentrations and either O_2or CO_2concentrations at the outlet of the SO_2control device (or the outlet of the steam generating unit if no SO_2control device is used), and shall record the output of the system. The owner or operator of an affected facility subject to the percent reduction requirements under §60.42c shall measure SO_2concentrations and either O_2or CO_2concentrations at both the inlet and outlet of the SO_2control device.

(b) The 1-hour average SO_2emission rates measured by a CEMS shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the average emission rates under §60.42c. Each 1-hour average

SO_2 emission rate must be based on at least 30 minutes of operation, and shall be calculated using the data points required under §60.13(h)(2). Hourly SO_2 emission rates are not calculated if the affected facility is operated less than 30 minutes in a 1-hour period and are not counted toward determination of a steam generating unit operating day.

(c) The procedures under §60.13 shall be followed for installation, evaluation, and operation of the CEMS.

(1) All CEMS shall be operated in accordance with the applicable procedures under Performance Specifications 1, 2, and 3 of appendix B of this part.

(2) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 1 of appendix F of this part.

(3) For affected facilities subject to the percent reduction requirements under §60.42c, the span value of the SO_2 CEMS at the inlet to the SO_2 control device shall be 125 percent of the maximum estimated hourly potential SO_2 emission rate of the fuel combusted, and the span value of the SO_2 CEMS at the outlet from the SO_2 control device shall be 50 percent of the maximum estimated hourly potential SO_2 emission rate of the fuel combusted.

(4) For affected facilities that are not subject to the percent reduction requirements of §60.42c, the span value of the SO_2 CEMS at the outlet from the SO_2 control device (or outlet of the steam generating unit if no SO_2 control device is used) shall be 125 percent of the maximum estimated hourly potential SO_2 emission rate of the fuel combusted.

(d) As an alternative to operating a CEMS at the inlet to the SO_2 control device (or outlet of the steam generating unit if no SO_2 control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO_2 emission rate by sampling the fuel prior to combustion. As an alternative to operating a CEMS at the outlet from the SO_2 control device (or outlet of the steam generating unit if no SO_2 control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO_2 emission rate by using Method 6B of appendix A of this part. Fuel sampling shall be conducted pursuant to either paragraph (d)(1) or (d)(2) of this section. Method 6B of appendix A of this part shall be conducted pursuant to paragraph (d)(3) of this section.

(1) For affected facilities combusting coal or oil, coal or oil samples shall be collected daily in an as-fired condition at the inlet to the steam generating unit and analyzed for sulfur content and heat content according the Method 19 of appendix A of this part. Method 19 of appendix A of this part provides procedures for converting these measurements into the format to be used in calculating the average SO_2 input rate.

(2) As an alternative fuel sampling procedure for affected facilities combusting oil, oil samples may be collected from the fuel tank for each steam generating unit immediately after the fuel tank is filled and before any oil is combusted. The owner or operator of the affected facility shall analyze the oil sample to determine the sulfur content of the oil. If a partially empty fuel tank is refilled, a new sample and analysis of the fuel in the tank would be required upon filling. Results of the fuel analysis taken after each new shipment of oil is received shall be used as the daily value when calculating the 30-day rolling average until the next shipment is received. If the fuel analysis shows that the sulfur content in the fuel tank is greater than 0.5 weight percent sulfur, the owner or operator shall ensure that the sulfur content of subsequent oil shipments is low enough to cause the 30-day rolling average sulfur content to be 0.5 weight percent sulfur or less.

(3) Method 6B of appendix A of this part may be used in lieu of CEMS to measure SO_2 at the inlet or outlet of the SO_2 control system. An initial stratification test is required to verify the adequacy of the Method 6B of appendix A of this part sampling location. The stratification test shall consist of three paired runs of a suitable SO_2 and CO_2 measurement train operated at the candidate location and a second similar train operated according to the procedures in §3.2 and the applicable procedures in section 7 of Performance Specification 2 of appendix B of this part. Method 6B of appendix A of this part, Method 6A of appendix A of this part, or a combination of Methods 6 and 3 of appendix A of this part or Methods 6C and 3A of appendix A of this part are suitable measurement techniques. If Method 6B of appendix A of this part is used for the second train, sampling time and timer operation may be adjusted for the stratification test as long as an adequate sample volume is collected; however, both sampling trains are to be operated similarly. For the location to be adequate for Method 6B of appendix A of this part 24-hour tests, the mean of the absolute difference between the three paired runs must be less than 10 percent (0.10).

(e) The monitoring requirements of paragraphs (a) and (d) of this section shall not apply to affected facilities subject to §60.42c(h) (1), (2), or (3) where the owner or operator of the affected facility seeks to demonstrate compliance with the SO_2 standards based on fuel supplier certification, as described under §60.48c(f), as applicable.

(f) The owner or operator of an affected facility operating a CEMS pursuant to paragraph (a) of this section, or conducting as-fired fuel sampling pursuant to paragraph (d)(1) of this section, shall obtain emission data for at least 75 percent of the operating hours in at least 22 out of 30 successive steam generating unit operating days. If this minimum data requirement is not met with a single monitoring system, the owner or operator of the affected facility shall supplement the emission data with data collected with other monitoring systems as approved by the Administrator.

§ 60.47c Emission monitoring for particulate matter.

(a) Except as provided in paragraphs (c), (d), (e), (f), and (g) of this section, the owner or operator of an affected facility combusting coal, oil, or wood that is subject to the opacity standards under §60.43c shall install, calibrate, maintain, and operate a continuous opacity monitoring system (COMS) for measuring the opacity of the emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility subject to an opacity standard in §60.43c(c) that is not required to use a COMS due to paragraphs (c), (d), (e), or (f) of this section that elects not to use a COMS shall conduct a performance test using Method 9 of appendix A–4 of this part and the procedures in §60.11 to demonstrate compliance with the applicable limit in §60.43c by April 29, 2011, within 45 days of stopping use of an existing COMS, or 180 days after initial startup of the facility, whichever is later, and shall comply with either paragraphs (a)(1), (a)(2), or (a)(3) of this section. The observation period for Method 9 of appendix A–4 of this part performance tests may be reduced from 3 hours to 60 minutes if all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent during the initial 60 minutes of observation.

(1) Except as provided in paragraph (a)(2) and (a)(3) of this section, the owner or operator shall conduct subsequent Method 9 of appendix A–4 of this part performance tests using the procedures in paragraph (a) of this section according to the applicable schedule in paragraphs (a)(1)(i) through (a)(1)(iv) of this section, as determined by the most recent Method 9 of appendix A–4 of this part performance test results.

(i) If no visible emissions are observed, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted;

(ii) If visible emissions are observed but the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 6 calendar months from the date that the most recent performance test was conducted;

(iii) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted; or

(iv) If the maximum 6-minute average opacity is greater than 10 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 45 calendar days from the date that the most recent performance test was conducted.

(2) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A–4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A–4 of this part performance tests, elect to perform subsequent monitoring using Method 22 of appendix A–7 of this part according to the procedures specified in paragraphs (a)(2)(i) and (ii) of this section.

(i) The owner or operator shall conduct 10 minute observations (during normal operation) each operating day the affected facility fires fuel for which an opacity standard is applicable using Method 22 of appendix A–7 of this part and demonstrate that the sum of the occurrences of any visible emissions is not in excess of 5 percent of the observation period (*i.e.* , 30 seconds per 10 minute period). If the sum of the occurrence of any visible emissions is greater than 30 seconds during the initial 10 minute observation, immediately conduct a 30 minute observation. If the sum of the occurrence of visible emissions is greater than 5 percent of the observation period (*i.e.,* 90 seconds per 30 minute period), the owner or operator shall either document and adjust the operation of the facility and demonstrate within 24 hours that the sum of the occurrence of visible emissions is equal to or less than 5 percent during a 30 minute observation (*i.e.,* 90 seconds) or conduct a new Method 9 of appendix A–4 of this part performance test using the procedures in paragraph (a) of this section within 45 calendar days according to the requirements in §60.45c(a)(8).

(ii) If no visible emissions are observed for 30 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

(3) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A–4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A–4 performance tests, elect to perform subsequent monitoring using a digital opacity compliance system according to a site-specific monitoring plan approved by the Administrator. The observations shall be similar, but not necessarily identical, to the requirements in paragraph (a)(2) of this section. For reference purposes in preparing the monitoring plan, see OAQPS “Determination of Visible Emission Opacity from Stationary Sources Using Computer-Based Photographic Analysis Systems.” This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality and Planning Standards; Sector Policies and Programs Division; Measurement Policy Group (D243–02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Preliminary Methods.

(b) All COMS shall be operated in accordance with the applicable procedures under Performance Specification 1 of appendix B of this part. The span value of the opacity COMS shall be between 60 and 80 percent.

(c) Owners and operators of an affected facilities that burn only distillate oil that contains no more than 0.5 weight percent sulfur and/or liquid or gaseous fuels with potential sulfur dioxide emission rates of 26 ng/J (0.060 lb/MMBtu) heat input or less and that do not use a post-combustion technology to reduce SO2 or PM emissions and that are subject to an opacity standard in §60.43c(c) are not required to operate a COMS if they follow the applicable procedures in §60.48c(f).

(d) Owners or operators complying with the PM emission limit by using a PM CEMS must calibrate, maintain, operate, and record the output of the system for PM emissions discharged to the atmosphere as specified in §60.45c(c). The CEMS specified in paragraph §60.45c(c) shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

(e) Owners and operators of an affected facility that is subject to an opacity standard in §60.43c(c) and that does not use post-combustion technology (except a wet scrubber) for reducing PM, SO_2, or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.5 weight percent sulfur, and is operated such that emissions of CO discharged to the atmosphere from the affected facility are maintained at levels less than or equal to 0.15 lb/MMBtu on a boiler operating day average basis is not required to operate a COMS. Owners and operators of affected facilities electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (e)(1) through (4) of this section; or

(1) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (e)(1)(i) through (iv) of this section.

(i) The CO CEMS must be installed, certified, maintained, and operated according to the provisions in §60.58b(i)(3) of subpart Eb of this part.

(ii) Each 1-hour CO emissions average is calculated using the data points generated by the CO CEMS expressed in parts per million by volume corrected to 3 percent oxygen (dry basis).

(iii) At a minimum, valid 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-day rolling average basis. The 1-hour averages are calculated using the data points required in §60.13(h)(2).

(iv) Quarterly accuracy determinations and daily calibration drift tests for the CO CEMS must be performed in accordance with procedure 1 in appendix F of this part.

(2) You must calculate the 1-hour average CO emissions levels for each steam generating unit operating day by multiplying the average hourly CO output concentration measured by the CO CEMS times the corresponding average hourly flue gas flow rate and divided by the corresponding average hourly heat input to the affected source. The 24-hour average CO emission level is determined by calculating the arithmetic average of the hourly CO emission levels computed for each steam generating unit operating day.

(3) You must evaluate the preceding 24-hour average CO emission level each steam generating unit operating day excluding periods of affected source startup, shutdown, or malfunction. If the 24-hour average CO emission level is greater than 0.15 lb/MMBtu, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high emission incident and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the 24-hour average CO emission level to 0.15 lb/MMBtu or less.

(4) You must record the CO measurements and calculations performed according to paragraph (e) of this section and any corrective actions taken. The record of corrective action taken must include the date and time during which the 24-hour average CO emission level was greater than 0.15 lb/MMBtu, and the date, time, and description of the corrective action.

(f) Owners and operators of an affected facility that is subject to an opacity standard in §60.43c(c) and that uses a bag leak detection system to monitor the performance of a fabric filter (baghouse) according to the most recent requirements in section §60.48Da of this part is not required to operate a COMS.

(g) Owners and operators of an affected facility that is subject to an opacity standard in §60.43c(c) and that burns only gaseous fuels or fuel oils that contain less than or equal to 0.5 weight percent sulfur and operates according to a written site-specific monitoring plan approved by the permitting authority is not required to operate a COMS. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009; 76 FR 3523, Jan. 20, 2011]

§ 60.48c   Reporting and recordkeeping requirements.

(a) The owner or operator of each affected facility shall submit notification of the date of construction or reconstruction and actual startup, as provided by §60.7 of this part. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.

(2) If applicable, a copy of any federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under §60.42c, or §60.43c.

(3) The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired.

(4) Notification if an emerging technology will be used for controlling SO_2emissions. The Administrator will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of §60.42c(a) or (b)(1), unless and until this determination is made by the Administrator.

(b) The owner or operator of each affected facility subject to the SO_2emission limits of §60.42c, or the PM or opacity limits of §60.43c, shall submit to the Administrator the performance test data from the initial and any subsequent performance tests and, if applicable, the performance evaluation of the CEMS and/or COMS using the applicable performance specifications in appendix B of this part.

(c) In addition to the applicable requirements in §60.7, the owner or operator of an affected facility subject to the opacity limits in §60.43c(c) shall submit excess emission reports for any excess emissions from the affected facility that occur during the reporting period and maintain records according to the requirements specified in paragraphs (c)(1) through (3) of this section, as applicable to the visible emissions monitoring method used.

(1) For each performance test conducted using Method 9 of appendix A–4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (c)(1)(i) through (iii) of this section.

(i) Dates and time intervals of all opacity observation periods;

(ii) Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test; and

(iii) Copies of all visible emission observer opacity field data sheets;

(2) For each performance test conducted using Method 22 of appendix A–4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (c)(2)(i) through (iv) of this section.

(i) Dates and time intervals of all visible emissions observation periods;

(ii) Name and affiliation for each visible emission observer participating in the performance test;

(iii) Copies of all visible emission observer opacity field data sheets; and

(iv) Documentation of any adjustments made and the time the adjustments were completed to the affected facility operation by the owner or operator to demonstrate compliance with the applicable monitoring requirements.

(3) For each digital opacity compliance system, the owner or operator shall maintain records and submit reports according to the requirements specified in the site-specific monitoring plan approved by the Administrator

(d) The owner or operator of each affected facility subject to the SO_2 emission limits, fuel oil sulfur limits, or percent reduction requirements under §60.42c shall submit reports to the Administrator.

(e) The owner or operator of each affected facility subject to the SO_2 emission limits, fuel oil sulfur limits, or percent reduction requirements under §60.42c shall keep records and submit reports as required under paragraph (d) of this section, including the following information, as applicable.

(1) Calendar dates covered in the reporting period.

(2) Each 30-day average SO_2 emission rate (ng/J or lb/MMBtu), or 30-day average sulfur content (weight percent), calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of corrective actions taken.

(3) Each 30-day average percent of potential SO_2 emission rate calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of the corrective actions taken.

(4) Identification of any steam generating unit operating days for which SO_2 or diluent (O_2 or CO_2) data have not been obtained by an approved method for at least 75 percent of the operating hours; justification for not obtaining sufficient data; and a description of corrective actions taken.

(5) Identification of any times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and a description of corrective actions taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit.

(6) Identification of the F factor used in calculations, method of determination, and type of fuel combusted.

(7) Identification of whether averages have been obtained based on CEMS rather than manual sampling methods.

(8) If a CEMS is used, identification of any times when the pollutant concentration exceeded the full span of the CEMS.

(9) If a CEMS is used, description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specifications 2 or 3 of appendix B of this part.

(10) If a CEMS is used, results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part.

(11) If fuel supplier certification is used to demonstrate compliance, records of fuel supplier certification as described under paragraph (f)(1), (2), (3), or (4) of this section, as applicable. In addition to records of fuel supplier certifications, the report shall include a certified statement signed by the owner or operator of the affected facility that the records of fuel supplier certifications submitted represent all of the fuel combusted during the reporting period.

(f) Fuel supplier certification shall include the following information:

(1) For distillate oil:

(i) The name of the oil supplier;

(ii) A statement from the oil supplier that the oil complies with the specifications under the definition of distillate oil in §60.41c; and

(iii) The sulfur content or maximum sulfur content of the oil.

(2) For residual oil:

(i) The name of the oil supplier;

(ii) The location of the oil when the sample was drawn for analysis to determine the sulfur content of the oil, specifically including whether the oil was sampled as delivered to the affected facility, or whether the sample was drawn from oil in storage at the oil supplier's or oil refiner's facility, or other location;

(iii) The sulfur content of the oil from which the shipment came (or of the shipment itself); and

(iv) The method used to determine the sulfur content of the oil.

(3) For coal:

(i) The name of the coal supplier;

(ii) The location of the coal when the sample was collected for analysis to determine the properties of the coal, specifically including whether the coal was sampled as delivered to the affected facility or whether the sample was collected from coal in storage at the mine, at a coal preparation plant, at a coal supplier's facility, or at another location. The certification shall include the name of the coal mine (and coal seam), coal storage facility, or coal preparation plant (where the sample was collected);

(iii) The results of the analysis of the coal from which the shipment came (or of the shipment itself) including the sulfur content, moisture content, ash content, and heat content; and

(iv) The methods used to determine the properties of the coal.

(4) For other fuels:

(i) The name of the supplier of the fuel;

(ii) The potential sulfur emissions rate or maximum potential sulfur emissions rate of the fuel in ng/J heat input; and

(iii) The method used to determine the potential sulfur emissions rate of the fuel.

(g)(1) Except as provided under paragraphs (g)(2) and (g)(3) of this section, the owner or operator of each affected facility shall record and maintain records of the amount of each fuel combusted during each operating day.

(2) As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility that combusts only natural gas, wood, fuels using fuel certification in §60.48c(f) to demonstrate compliance with the SO_2standard, fuels not subject to an emissions standard (excluding opacity), or a mixture of these fuels may elect to record and maintain records of the amount of each fuel combusted during each calendar month.

(3) As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility or multiple affected facilities located on a contiguous property unit where the only fuels combusted in any steam generating unit (including steam generating units not subject to this subpart) at that property are natural gas, wood, distillate oil meeting the most current requirements in §60.42C to use fuel certification to demonstrate compliance with the SO_2standard, and/or fuels, excluding coal and residual oil, not subject to an emissions standard (excluding opacity) may elect to record and maintain records of the total amount of each steam generating unit fuel delivered to that property during each calendar month.

(h) The owner or operator of each affected facility subject to a federally enforceable requirement limiting the annual capacity factor for any fuel or mixture of fuels under §60.42c or §60.43c shall calculate the annual capacity factor individually for each fuel combusted. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of the calendar month.

(i) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record.

(j) The reporting period for the reports required under this subpart is each six-month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009]

Indiana Department of Environmental Management
Office of Air Quality

Technical Support Document (TSD) for an Exemption Transitioning to a Registration

Source Description and Location

Source Name:	**Micronutrients, A Division of Heritage Technologies, LLC**
Source Location:	**1550 Research Way, Indianapolis, Indiana, 46231**
County:	**Marion**
SIC Code:	**2819 (Industrial Inorganic Chemicals)**
Registration No.:	**097-30945-00417**
Permit Reviewer:	**Sarah Street**

On September 20, 2011, the Office of Air Quality (OAQ) received an application from Micronutrients, A Division of Heritage Technologies, LLC related to the construction and operation of new emission units at an existing inorganic chemical manufacturing of animal feed supplements source and transition from an Exemption to a Registration.

Existing Approvals

The source has been operating under previous approvals including, but not limited to, the following:

(a) Exemption No. 097-15263-00417, issued on December 27, 2001.

(b) Registration No. 097-15697-00417, issued on April 15, 2003.

(c) Exemption No. 097-17665-00417, issued on May 16, 2003.

Due to this application, the source is transitioning from an Exemption to a Registration.

County Attainment Status

The source is located in Marion County.

Pollutant	Designation
SO_2	Better than national standards.
CO	Attainment effective February 18, 2000, for the part of the city of Indianapolis bounded by 11th Street on the north; Capitol Avenue on the west; Georgia Street on the south; and Delaware Street on the east. Unclassifiable or attainment effective November 15, 1990, for the remainder of Indianapolis and Marion County.
O_3	Attainment effective November 8, 2007, for the 8-hour ozone standard.[1]
PM_{10}	Unclassifiable effective November 15, 1990.
NO_2	Cannot be classified or better than national standards.
Pb	Attainment effective July 10, 2000, for the part of Franklin Township bounded by Thompson Road on the south; Emerson Avenue on the west; Five Points Road on the east; and Troy Avenue on the north. Attainment effective July 10, 2000, for the part of Wayne Township bounded by Rockville Road on the north; Girls School Road on the east; Washington Street on the south; and Bridgeport Road on the west. The remainder of the county is not designated.
[1]Attainment effective October 18, 2000, for the 1-hour ozone standard for the Indianapolis area, including Marion County, and is a maintenance area for the 1-hour ozone National Ambient Air Quality Standards (NAAQS) for purposes of 40 CFR 51, Subpart X*. The 1-hour designation was revoked effective June 15, 2005. Basic nonattainment designation effective federally April 5, 2005, for PM2.5.	

(a) Ozone Standards
Volatile organic compounds (VOC) and Nitrogen Oxides (NOx) are regulated under the Clean Air Act (CAA) for the purposes of attaining and maintaining the National Ambient Air Quality Standards (NAAQS) for ozone. Therefore, VOC and NOx emissions are considered when evaluating the rule applicability relating to ozone. Marion County has been designated as attainment or unclassifiable for ozone. Therefore, VOC and NOx emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

(b) $PM_{2.5}$
Marion County has been classified as nonattainment for $PM_{2.5}$ in 70 FR 943 dated January 5, 2005. On May 8, 2008, U.S. EPA promulgated specific New Source Review rules for $PM_{2.5}$ emissions. These rules became effective on July 15, 2008. Therefore, direct $PM_{2.5}$ and SO_2 emissions were reviewed pursuant to the requirements of Nonattainment New Source Review, 326 IAC 2-1.1-5. See the State Rule Applicability – Entire Source section.

(c) Other Criteria Pollutants
Marion County has been classified as attainment or unclassifiable in Indiana for all other criteria pollutants. Therefore, these emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

Fugitive Emissions

The fugitive emissions of criteria pollutants, hazardous air pollutants, and greenhouse gases are counted toward the determination of 326 IAC 2-5.1-2 (Registrations) applicability.

Background and Description of Emission Units and Pollution Control Equipment

The Office of Air Quality (OAQ) has reviewed an application, submitted by Micronutrients, A Division of Heritage Technologies, LLC on September 20, 2011, relating to the construction and operation of new emission units at an existing inorganic chemical manufacturing of animal feed supplements source and transition from an Exemption to a Registration. The source plans to construct new emission units, including, but not limited to a steam generator, dryer systems, HCL scrubber, and a material processing system at a new building identified as the BTMP plant.

The source consists of the following existing emission units and pollution control devices located at the Plant:

(a) One (1) natural gas-fired scotch boiler, identified as HB-1, installed in 1998, with a maximum heat input capacity of 8.4 million Btu per hour (MMBtu/hr), and exhausting to stack B-1.

(b) One (1) natural gas-fired scotch boiler, identified as HB-2, installed in 2002, with a maximum heat input capacity of 12.6 million Btu per hour (MMBtu/hr), and exhausting to stack B-2.

Under the NSPS Small Industrial-Commercial-Institutional Steam Generating Units (40 CFR 60.40b, Subpart Dc) the boiler HB-2 is considered an affected facility.

(c) One (1) natural gas-fired production dryer, identified as PD-1, installed in 1995, with a maximum heat input capacity of 1.5 million Btu per hour (MMBtu/hr), and a maximum process weight rate of 1.15 tons basic copper chloride per hour, using an integral cyclone and an integral dust collector (DC-1) as control, and exhausting to stack D-1.

(d) One (1) natural gas-fired R&D pilot dryer, identified as PD-2, constructed in 2002, with a maximum heat input capacity of 1.0 million Btu per hour (MMBtu/hr), using an integral dust collector as control, and exhausting to stack D-2.

(e) One (1) hydrochloric acid (HCl) receiving tank, identified as T-122, constructed in 1994, with a maximum capacity of 5,137 gallons, using no control device and exhausting indoors.

(f) One (1) hydrochloric acid (HCl) receiving tank, identified as T-122B, constructed in 2005, with a maximum capacity of 10,846 gallons, using no control device and exhausting indoors.

(g) One (1) hydrochloric acid (HCl) process tank, identified as R-156, with a maximum capacity of 4,889 gallons, with emissions from R-156 controlled by one (1) plant HCl scrubber, identified as PS-2, constructed in 2008, and exhausting to stack (S-2).

(h) One (1) hydrochloric acid (HCl) process tank, identified as R-104, with a maximum capacity of 2,760 gallons, with emissions from R-104 controlled by one (1) plant HCl scrubber, identified as PS-2, constructed in 2008, and exhausting to stack (S-2).

(i) One (1) existing material processing system, constructed in (1995), including, but not limited to, pneumatic conveyance process equipment associated with the transfer of material to and within the facility, including liquid tanks, hoppers, shaker screen, silos, conveyors, bucket elevators, and associated pollution control equipment including cyclones and dust collectors. The material processing system includes the following emission units:

(1) One (1) bucket elevator, identified as E-111, constructed in 1995, with a maximum capacity of 3 tons per hour, using an integral dust collector DC-2 as control, and exhausting indoors.

(2) One (1) bucket elevator, identified as E-136, constructed in 2010, with a maximum capacity of 3 tons per hour, using an integral dust collector DC-2 as control, and exhausting indoors.

(3) One (1) bucket elevator, identified as E-137, constructed in 2010, with a maximum capacity of 3 tons per hour, using an integral dust collector DC-2 as control, and exhausting indoors.

(4) One (1) Packaging area, identified as BU-1, constructed in 2010, with a maximum capacity of 3 tons per hour, using an integral dust collector DC-2 as control, and exhausting indoors.

Note: The following table summarizes additional equipment in the existing material processing system that are not considered emission units because they do not have a potential to emit. This is for inventory purpose only.

	Year of Construction	Emission Control Equipment	Stack ID	Description
Tank Reactor	1995	Liquid reactor with a half closed top. No emission control equipment.	Not associated with any stack	This is a liquid reactor without any control equipment and negligible exhaust. R-101 is not considered an emission unit because it does not have a potential to emit.

	Year of Construction	Emission Control Equipment	Stack ID	Description
Komline	1995	Belt Filter press filtering slurry from the reactor. No emission control equipment	Not associated with any stack	This is a liquid system without any control equipment and negligible exhaust. The komline is not considered an emission unit because it does not have a potential to emit.
Wet Hopper - 1 (WH-1)	2010	A hopper chute for the addition of wet copper material. No emission control equipment	Not associated with any stack	This is a chute where copper material is added to the processing system. There is not any associated control equipment, and any fugitive emissions remain inside the plant.
Screw Conveyors (4)	1995 & 2010	Each screw conveyor is closed and tightly sealed. No emission control equipment	Not associated with any stack	These screw conveyors have tightly sealed drop points and closed tops. There is not any associated control equipment. The screw conveyors are not considered emission units because they have no potential to emit.
Shaker Screen	1995	The Shaker screen is a tightly sealed unit. No emission control equipment	NA	The shaker screen is a process step to prevent product clumping, and is tightly sealed. The shaker screen is not considered an emission unit because it has no potential to emit.
Silos	1995 & 2010	The silos are tightly sealed closed top tanks with tightly sealed drop points from the bucket elevators. Fine particulates are pulled from the head space by DC-2	Not associated with any stack, DC-2 exhaust internally	The silos are tightly sealed tanks. DC-2 pulls fine particulates from the head space and exhaust internally. The silos are not considered to be emission units because they have no potential to emit.
Air Classifier System (DC-3)	2010	None	D-3	The plant air classifier system sorts products according to size and has no emissions or control device.

The following is a list of the new emission units and pollution control devices located at the BTMP Plant:

(j) One (1) natural gas-fired BTMP plant steam generator, identified as BB-1, approved in 2011 for construction, with a maximum heat input capacity of 12.6 million British thermal units per hour (MMBtu/hr), and exhausting to stack B-3.

Under the NSPS Small Industrial-Commercial-Institutional Steam Generating Units (40 CFR 60.40b, Subpart Dc) the boiler BB-1 is considered an affected facility.

(k) One (1) BTMP plant dryer system, identified as BD-4, approved in 2011 for construction, with a maximum capacity of 2.5 million British thermal units per hour (MMBtu/hr), using an integral dust collector DC-4 as control, and exhausting to stack D-4.

(l) One (1) BTMP plant dryer system, identified as BD-5, approved in 2011 for construction, with a maximum capacity of 2.5 million British thermal units per hour (MMBtu/hr), using an integral dust collector DC-5 as control, and exhausting to stack D-5.

(m) One (1) BTMP plant dryer system, identified as BD-6, approved in 2011 for construction, with a maximum capacity of 2.5 million British thermal units per hour (MMBtu/hr), using an integral dust collector DC-6 as control, and exhausting to stack D-6.

(n) One (1) BTMP plant dryer system, identified as BD-7, approved in 2011 for construction, with a maximum capacity of 2.5 million British thermal units per hour (MMBtu/hr), using an integral dust collector DC-7 as control, and exhausting to stack D-7.

(o) One (1) BTMP plant dryer system, identified as BD-8, approved in 2011 for construction, with a maximum capacity of 2.5 million British thermal units per hour (MMBtu/hr), using an integral dust collector DC-8 as control, and exhausting to stack D-8.

(p) One (1) hydrochloric acid (HCl) receiving tank, identified as T-211, with a maximum capacity of 19,807 gallons, with emissions from T-211 controlled by one (1) BTMP plant HCl scrubber, identified as BS-4 , approved in 2011 for construction with a maximum capacity of 3,000 CFM and exhausting to stack S-4.

(q) One (1) new material processing system, approved in 2011 for construction, including, but not limited to, pneumatic conveyance process equipment associated with the transfer of material to and within the facility, including liquid tanks, hoppers, storage tanks, conveyors, bagging areas, and associated pollution control equipment including cyclones and dust collectors. The material processing system includes the following emission units:

  (1) One (1) Dump hopper, identified as BD-310, approved in 2011 for construction, with a maximum capacity of 1 tons per hour, using integral dust collectors BN-1 and BL-1 as control, and exhausting indoors.

  (2) One (1) Dump hopper, identified as BD-320, approved in 2011 for construction, with a maximum capacity of 1 tons per hour, using integral dust collectors BN-1 and BL-1 as control, and exhausting indoors.

  (3) One (1) Dump hopper, identified as BD-330, approved in 2011 for construction, with a maximum capacity of 1 tons per hour, using integral dust collectors BN-1 and BL-1 as control, and exhausting indoors.

  (4) One (1) Bagging area, identified as BU-2, approved in 2011 for construction, with a maximum capacity of 1 tons per hour, using an integral dust collector BN-2 as control, and exhausting indoors.

  (5) One (1) Bagging area, identified as BU-3, approved in 2011 for construction, with a maximum capacity of 1 tons per hour, using an integral dust collector BN-2 as control, and exhausting indoors.

  (6) One (1) Bagging area, identified as BU-4, approved in 2011 for construction, with a maximum capacity of 1 tons per hour, using an integral dust collector BN-2 as control, and exhausting indoors.

  Note: The following table summarizes additional equipment in the new material processing system that are not considered emission units because they do not have a potential to emit. This is for inventory purpose only.

	Year of Construction	Emission Control Equipment	Stack ID	Description
Reactors	2011	The reactors are closed tanks, and will have a wet chemistry. There will not be any control equipment associated with these tanks	NA	The reactors are tightly sealed tanks where wet chemistry will take place. The reactors are not considered emission units because there is no potential for them to emit.
Slurry Tanks	2011	The slurry tanks are closed tanks, and will store a wet slurry. There will not be any control equipment associated with these tanks	NA	The slurry tanks are tightly sealed tanks where a wet slurry will be held. The slurry tanks are not considered emission units because there is no potential for them to emit.
Blending Tanks	2011	The blending tanks are closed tanks, and will store a wet slurry. There will not be any control equipment associated with these tanks	NA	The blending tanks are tightly sealed tanks where a wet slurry will be held. The slurry tanks are not considered emission units because there is no potential for them to emit.
Storage Tanks	2011	The storage tanks are tightly closed tanks. There will not be any control equipment associated with these tanks.	NA	The storage tanks store finished product prior to packaging

“Integral Part of the Process” Determination

The Permittee has submitted the following information to justify why the cyclones and dust collectors should be considered an integral part of the material processing systems (bucket elevators, packaging areas, dryer systems, hoppers, bagging areas):

(a) The cyclones and dust collectors should be considered an integral part of the drying systems and material processing systems at both the Plant and the BTMP Plant. The control equipment serves a primary purpose other than pollution control. The primary purpose is product or raw material recovery. For both processes size control of the finished particle is necessary as it is part of the product’s specification. We utilize the cyclones and dust collectors to eliminate the smaller particles from the finished product. Removing these smaller particles is necessary to produce product meeting our specifications.

(b) The control equipment has an overwhelming positive net economic effect. 100% of the material recovered by the cyclones and dust collectors is either utilized as product or is returned to the process as feedstock. Around 200 tons of Copper Hydroxy Chloride are returned to the system as feedstock per month. This represents 116 tons of copper and close to $800,000 dollars a month. Reusing this material is necessary for Micronutrients to operate profitably.

IDEM, OAQ has evaluated the information submitted and agrees that the cyclones and dust collectors should be considered an integral part of the drying systems and material processing systems. This determination is based on the fact that the control equipment has an overwhelming positive net economic effect. Therefore, the permitting level will be determined using the potential to emit after the cyclones and dust collectors. Operating conditions in the proposed permit will specify that the cyclones and dust collectors shall operate at all times when the associated drying systems and material processing systems are in operation. This determination was similar to the initial determination made for T & S Equipment Company under Registration No. 151-29813-00053, issued on February 16, 2011.

Enforcement Issues

There are no pending enforcement actions related to this source.

Emission Calculations

See Appendix A of this TSD for detailed emission calculations.

Permit Level Determination – Registration

The following table reflects the unlimited potential to emit (PTE) of the entire source before controls. Control equipment is not considered federally enforceable until it has been required in a federally enforceable permit.

	Potential To Emit of the Entire Source (tons/year)									
	PM	PM10*	PM2.5	SO_2	NOx	VOC	CO	GHGs as CO_2e**	Total HAPs	Worst Single HAP
HB-1, HB-2, PD-1 and R&D pilot dryer from combustion	0.20	0.78	0.78	0.06	10.29	0.57	8.65	12,426.77	0.19	0.177 (Hexane)
[1]PD-1 from drying	1.11E-03	2.77E-03	4.73E-04	-	-	-	-	-	-	-
T-122	-	-	-	-	-	-	-	-	0.108	0.108 (HCl)
T-122B	-	-	-	-	-	-	-	-	0.198	0.198 (HCl)
R-156	-	-	-	-	-	-	-	-	0.065	0.065 (HCl)
R-104	-	-	-	-	-	-	-	-	0.052	0.052 (HCl)
[1]existing material processing system (tanks, hoppers, shaker screen, silos, conveyors, bucket elevators)	7.14E-04	1.09E-03	1.09E-03	-	-	-	-	-	-	-
BB-1, BD-4, BD-5, BD-6, BD-7 and BD-8 from combustion	0.21	0.84	0.84	0.07	10.99	0.60	9.23	13,272.85	0.21	0.198 (Hexane)
BD-4, BD-5, BD-6, BD-7 and BD-8 from drying	5.54E-03	1.39E-02	2.37E-03	-	-	-	-	-	-	-
T-211	-	-	-	-	-	-	-	-	0.329	0.329 (HCl)
[1] new material processing system (tanks, hoppers, conveyors, bagging areas)	2.67E-04	4.34E-04	4.34E-04	-	-	-	-	-	-	-
Paved Roads	0.35	0.07	0.02	-	-	-	-	-	-	-
Total PTE of Entire Source	**0.77**	**1.71**	**1.64**	**0.13**	**21.29**	**1.17**	**17.88**	**25,699.62**	**1.15**	**0.375 (Hexane) and 0.751 (HCl)**

	Potential To Emit of the Entire Source (tons/year)									
	PM	PM10*	PM2.5	SO_2	NOx	VOC	CO	GHGs as CO_2e**	Total HAPs	Worst Single HAP
Exemptions Levels**	5	5	5	10	10	5	25	100,000	25	10
Registration Levels**	25	25	25	25	25	25	100	100,000	25	10

- = negligible

*Under the Part 70 Permit program (40 CFR 70), particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers (PM10), not particulate matter (PM), is considered as a "regulated air pollutant".
**The 100,000 CO_2e threshold represents the Title V and PSD subject to regulation thresholds for GHGs in order to determine whether a source's emissions are a regulated NSR pollutant under Title V and PSD.
Note 1: The emission units above are controlled by integral cyclones and dust collectors. See "Integral Part of the Process" Determination section of this technical support document for additional details on the integral control devices at this source. Therefore, the PTE after the control shall be used for permit level determination.

(a) The potential to emit (PTE) (as defined in 326 IAC 2-1.1-1) of pollutants NO_X and CO are within the ranges listed in 326 IAC 2-5.1-2(a)(1). The PTE of all other regulated criteria pollutants are less than the ranges listed in 326 IAC 2-5.1-2(a)(1). Therefore, the source is subject to the provisions of 326 IAC 2-5.1-2 (Registrations). A Registration will be issued.

(b) The potential to emit (PTE) (as defined in 326 IAC 2-1.1-1) of any single HAP is less than ten (10) tons per year and the PTE of a combination of HAPs is less than twenty-five (25) tons per year. Therefore, this source is an area source under Section 112 of the Clean Air Act (CAA) and not subject to the provisions of 326 IAC 2-7.

(c) The potential to emit (PTE) (as defined in 326 IAC 2-1.1-1) greenhouse gases (GHGs) is less than the Title V subject to regulation threshold of one hundred thousand (100,000) tons of CO_2 equivalent emissions (CO_2e) per year. Therefore, the source is not subject to the provisions of 326 IAC 2-7.

Federal Rule Applicability Determination

New Source Performance Standards (NSPS)

(a) The requirements of the New Source Performance Standard for Small Industrial-Commercial-Institutional Steam Generating Units, 40 CFR 60, Subpart Dc (326 IAC 12), are not included in the permit for boiler HB-1 , since it has a maximum design heat input capacity less than 2.9 MW (10 MMBtu/hr).

(b) The requirements of the New Source Performance Standard for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984, 40 CFR 60, Subpart Kb (326 IAC 12), are not included in the permit for the hydrochloric acid (HCl) tanks, identified as T-122, T-122B, T-211, R-156, and R-104, because they each have a maximum storage capacity less than 75 cubic meters (19,813 gallons).

(c) Boilers HB-2 and BB-1 are both subject to the New Source Performance Standards for Small Industrial-Commercial-Institutional Steam Generating Units (40 CFR 60, Subpart Dc), because the boilers were constructed after the rule applicability date of June 1989, and each of the boilers is rated at less than one hundred (100) MMBtu per hour, but greater than ten (10) MMBtu per hour.

The entire rule is included as Attachment A of the permit. Applicable portions of the NSPS are the following:

(1) 40 CFR 60.40c(a)

(2) 40 CFR 60.41c
(3) 40 CFR 60.48c (a), (g)(1)-(3), and (i)

The requirements of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated as 326 IAC 12-1, apply to boilers HB-2 and BB-1 except as otherwise specified in 40 CFR 60, Subpart Dc.

(d) There are no other New Source Performance Standards (NSPS) (326 IAC 12 and 40 CFR Part 60) included in the permit.

National Emission Standards for Hazardous Air Pollutants (NESHAP)

(e) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Industrial, Commercial, and Institutional Boilers Area Sources, 40 CFR 63, Subpart JJJJJJ (6J), are not included in the permit for the boilers HB-1, HB-2 and BB-1, because gas-fired boilers, as defined in 40 CFR 63.11237, are specifically exempted from this rule as indicated in 40 CFR 63.11195(e).

(f) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Chemical Manufacturing Area Sources, 40 CFR 63, Subpart VVVVVV (6V), are not included in the permit for the source, because the NAICS Code for this source is 325188 and pursuant to 40 CFR 63.11494(c)(2), this Subpart 6V does not apply to chemical manufacturing materials described in NAICS code 325.

(g) There are no National Emission Standards for Hazardous Air Pollutants (NESHAPs) (326 IAC 14, 326 IAC 20 and 40 CFR Part 63) included in the permit.

Compliance Assurance Monitoring (CAM)

(h) Pursuant to 40 CFR 64.2, Compliance Assurance Monitoring (CAM) is not included in the permit, because the unlimited potential to emit of the source is less than the Title V major source thresholds and the source is not required to obtain a Part 70 or Part 71 permit.

State Rule Applicability Determination

(a) 326 IAC 2-5.1-2 (Registrations)
Registration applicability is discussed under the Permit Level Determination – Registration section above.

(b) 326 IAC 2-4.1 (Major Sources of Hazardous Air Pollutants (HAP))
The potential to emit of any single HAP is less than ten (10) tons per year and the potential to emit of a combination of HAPs is less than twenty-five (25) tons per year. Therefore, this source is an area source under Section 112 of the Clean Air Act (CAA) and not subject to the provisions of 326 IAC 2-4.1.

(c) 326 IAC 2-6 (Emission Reporting)
Pursuant to 326 IAC 2-6-1, this source is not subject to this rule, because it is not required to have an operating permit under 326 IAC 2-7 (Part 70), it is not located in Lake, Porter, or LaPorte County, and it does not emit lead into the ambient air at levels equal to or greater than 5 tons per year. Therefore, 326 IAC 2-6 does not apply.

(d) 326 IAC 5-1 (Opacity Limitations)
Pursuant to 326 IAC 5-1-2 (Opacity Limitations), except as provided in 326 IAC 5-1-3 (Temporary Alternative Opacity Limitations), opacity shall meet the following, unless otherwise stated in this permit:

(1) Opacity shall not exceed an average of thirty percent (30%) in any one (1) six (6) minute averaging period as determined in 326 IAC 5-1-4.

(2) Opacity shall not exceed sixty percent (60%) for more than a cumulative total of fifteen (15) minutes (sixty (60) readings as measured according to 40 CFR 60, Appendix A, Method 9 or fifteen (15) one (1) minute nonoverlapping integrated averages for a continuous opacity monitor) in a six (6) hour period.

(e) 326 IAC 6-4 (Fugitive Dust Emissions Limitations)
Pursuant to 326 IAC 6-4 (Fugitive Dust Emissions Limitations), the source shall not allow fugitive dust to escape beyond the property line or boundaries of the property, right-of-way, or easement on which the source is located, in a manner that would violate 326 IAC 6-4.

(f) 326 IAC 6-5 (Fugitive Particulate Matter Emission Limitations)
The source is not subject to the requirements of 326 IAC 6-5, because the source does not have potential fugitive particulate emissions greater than 25 tons per year. Therefore, 326 IAC 6-5 does not apply.

(g) 326 IAC 8-1-6 (VOC Rules: General Reduction Requirements for New Facilities)
Each of the emission units at this source is not subject to the requirements of 326 IAC 8-1-6, since the unlimited VOC potential emissions from each emission unit is less than twenty-five (25) tons per year.

(h) 326 IAC 6.5 (Particulate Matter Limitations Except Lake County)
The source is located in Marion County and the PM PTE is less than 10 tons per year. Therefore, the source is not subject to the requirements of 326 IAC 6.5.

Note: Actual emissions are not available. However, since the potential emission are less than 10 tons per year, it can be assumed that actual emissions are less than 10 tons per year.

(i) 326 IAC 7-1 (Sulfur Dioxide Emission Limitations)
This rule does not apply to this source because the potential to emit of each individual emission unit is less than 25 tons per year or 10 pounds per hour of Sulfur Dioxide.

Boilers

(j) 326 IAC 6-2-4 (Particulate Emission Limitations for Sources of Indirect Heating)
Pursuant to 326 IAC 6-2-4 (Particulate Matter Emission Limitations for Sources of Indirect Heating), indirect heating units constructed after September 21, 1983 shall be limited using the following equation:

$$Pt = \frac{1.09}{Q^{0.26}}$$

where: Pt = Pounds of particulate matter emitted per million British thermal units (lb/MMBtu) heat input

Q = Total source maximum operating capacity rating in million British thermal units per hour (MMBtu/hr) heat input. The maximum operating capacity rating is defined as the maximum capacity at which the facility is operated or the nameplate capacity, whichever is specified in the facility’s permit application, except when some lower capacity is contained in the facility’s operation permit; in which case, the capacity specified in the operation permit shall be used.

For	Boiler HB-1	Q= 8.4
For	Boiler HB-2	Q= 21.0 = 8.4 + 12.6
For	Boiler BB-1	Q= 33.6 = 8.4 + 12.6 + 12.6

For HB-1 Pursuant to 326 IAC 6-2-4(a), for Q less than ten (10) million Btu per hour (MMBtu/hr), particulate emissions shall not exceed 0.6 pounds per million Btu (lbs/MMBtu).

For HB-2 $Pt = 1.09/(21.0)^{0.26}$ = 0.494 lbs PM/MMBtu heat input

For BB-1 $Pt = 1.09/(33.6)^{0.26}$ = 0.437 lbs PM/MMBtu heat input

The potential to emit of PM from HB-1, with a maximum heat input capacity of 8.4 MMBtu/hr, is 0.07 tons per year.

0.07 tons/yr × (2000 lbs/ton / 8760 hrs/yr) = 0.016 lbs/hr
(0.016 lbs/hr / 8.4 MMBtu/hr) = 0.0019 lbs PM per MMBtu

The 0.0019 lbs/MMBtu emission rate estimated using the AP-42 emission factor is less than the 0.6 lb/MMBtu limit. Therefore, boiler HB-1 is able to comply with 326 IAC 6-2-4.

The potential to emit of PM from HB-2, with a maximum heat input capacity of 12.6 MMBtu/hr, is 0.105 tons per year.

0.105 tons/yr × (2000 lbs/ton / 8760 hrs/yr) = 0.024 lbs/hr
(0.024 lbs/hr / 12.6 MMBtu/hr) = 0.0019 lbs PM per MMBtu

The 0.0019 lbs/MMBtu emission rate estimated using the AP-42 emission factor is less than the 0.494 lb/MMBtu limit. Therefore, boiler HB-2 is able to comply with 326 IAC 6-2-4.

The potential to emit of PM from BB-1, with a maximum heat input capacity of 12.6 MMBtu/hr, is 0.105 tons per year.

0.105 tons/yr × (2000 lbs/ton / 8760 hrs/yr) = 0.024 lbs/hr
(0.024 lbs/hr / 12.6 MMBtu/hr) = 0.0019 lbs PM per MMBtu

The 0.0019 lbs/MMBtu emission rate estimated using the AP-42 emission factor is less than the 0.437 lb/MMBtu limit. Therefore, boiler BB-1 is able to comply with 326 IAC 6-2-4.

(k) 326 IAC 6-3 (Particulate Emission Limitations for Manufacturing Processes)
The boilers, identified as HB-1, HB-2 and BB-1, are each exempt from the requirements of 326 IAC 6-3 since they are sources of indirect heating.

Dryers

(l) 326 IAC 6-2 (Particulate Emission Limitations for Sources of Indirect Heating)
326 IAC 6-2 applies to sources of indirect heating. The dryers are not considered sources of indirect heating. Therefore, 326 IAC 6-2 does not apply.

(m) 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes)
(a) The one (1) R&D pilot dryer, identified as PD-2, has potential emissions less than five hundred fifty-one thousandths (0.551) pound per hour, before control. In addition, pursuant to 326 IAC 1-2-59(a), liquid and gaseous fuels and combustion air will not be

considered as part of the process weight. Therefore, pursuant to 326 IAC 6-3-1(b)(14), the R&D pilot dryer, identified as PD-2 is exempt from this rule.

(b) Pursuant to 326 IAC 6-3-2, the particulate emissions from each of the following processes shall not exceed the pound per hour limitations specified in the following table:

Emission unit ID	Control ID	Maximum Process Weight (tons/hour) for each unit	326 IAC 6-3 Limit (lbs/hr) for each unit
PD-1	DC-1	1.15	4.50
BD-4	DC-4	1.15	4.50
BD-5	DC-5	1.15	4.50
BD-6	DC-6	1.15	4.50
BD-7	DC-7	1.15	4.50
BD-8	DC-8	1.15	4.50

The particulate emissions limitations from the above table shall be calculated using the following equation:

Interpolation of the data for the process weight rate up to sixty thousand (60,000) pounds per hour shall be accomplished by use of the equation:

$E = 4.10\ P^{0.67}$ where E = rate of emission in pounds per hour; and
P = process weight rate in tons per hour

Based on calculations, the control devices are not needed to comply with these limits.

<u>Material processing systems</u>

(n) 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes)
All of the material process system emission units, including E-111, E-136, E-137, BU-1, BD-310, BD320, BD-330, BU-2, BU-3 and BU-4, each have potential emissions less than five hundred fifty-one thousandths (0.551) pound per hour (before control). Therefore, pursuant to 326 IAC 6-3-1(b)(14), the material process system emission units are all exempt from this rule.

(o) 326 IAC 12 (New Source Performance Standards)
See Federal Rule Applicability Section of this TSD.

Compliance Determination, Monitoring and Testing Requirements

The compliance determination and monitoring requirements applicable to this proposed revision are as follows:

Emission Unit/Control	Operating Parameters
Integral control devices DC-1, and DC-4 through DC-8	Operate at all times

Conclusion and Recommendation

Unless otherwise stated, information used in this review was derived from the application and additional information submitted by the applicant. An application for the purposes of this review was received on September 20, 2011.

The construction and operation of this source shall be subject to the conditions of the attached proposed Registration No. 097-30945-00417. The staff recommends to the Commissioner that this Registration be approved.

IDEM Contact

(a) Questions regarding this proposed permit can be directed to Sarah Street at the Indiana Department Environmental Management, Office of Air Quality, Permits Branch, 100 North Senate Avenue, MC 61-53 IGCN 1003, Indianapolis, Indiana 46204-2251 or by telephone at (317) (232-8427) or toll free at 1-800-451-6027 extension (2-8427).

(b) A copy of the findings is available on the Internet at: http://www.in.gov/ai/appfiles/idem-caats/

(c) For additional information about air permits and how the public and interested parties can participate, refer to the IDEM's Guide for Citizen Participation and Permit Guide on the Internet at: www.in.gov/idem

Appendix A: Emission Calculations
Summary of Modified Source

Company Name: Micronutrients, A Division of Heritage Technologies, LLC
Address City IN Zip: 1550 Research Way, Indianapolis, Indiana, 46231
Permit Number: 097-30945-00417
Reviewer: Sarah Street
Date: 10/11/2011

	Uncontrolled PTE (tons/year) of existing permitted units									
Emission Unit	PM (tons/yr)	PM10 (tons/yr)	PM2.5 (tons/yr)	SO_2 (tons/yr)	NOx (tons/yr)	VOC (tons/yr)	CO (tons/yr)	GHGs as CO2e (tons/yr)	Total HAPs (tons/yr)	Worst Single HAP (tons/yr)
HB-1, HB-2, PD-1 and R&D pilot dryer from combustion	0.20	0.78	0.78	0.06	10.29	0.57	8.65	12,426.77	0.194	0.177 (Hexane)
[1]PD-1 from drying	1.11E-03	2.77E-03	4.73E-04	-	-	-	-	-	-	-
Paved Roads	0.35	0.07	0.02	-	-	-	-	-	-	-
Total PTE of permitted units	**0.55**	**0.86**	**0.80**	**0.06**	**10.29**	**0.57**	**8.65**	**12,426.77**	**0.19**	**0.177 (Hexane)**

- = negligible

Note 1: The emission units above are controlled by integral cyclones and dust collectors. See the technical support document of this permit for additional details on the integral control devices at this source. Therefore, the PTE after the control shall be used for permit level determination.

	Uncontrolled PTE (tons/year) of other existing emission units									
Emission Unit	PM (tons/yr)	PM10 (tons/yr)	PM2.5 (tons/yr)	SO_2 (tons/yr)	NOx (tons/yr)	VOC (tons/yr)	CO (tons/yr)	GHGs as CO2e (tons/yr)	Total HAPs (tons/yr)	Worst Single HAP (tons/yr)
T-122	-	-	-	-	-	-	-	-	0.108	0.108 (HCl)
T-122B	-	-	-	-	-	-	-	-	0.198	0.198 (HCl)
R-156	-	-	-	-	-	-	-	-	0.065	0.065 (HCl)
R-104	-	-	-	-	-	-	-	-	0.052	0.052 (HCl)
[1]existing material processing system (tanks, hoppers, shaker screen, silos, conveyors, bucket elevators)	7.14E-04	1.09E-03	1.09E-03	-	-	-	-	-	-	-
Total PTE of other existing	**7.14E-04**	**1.09E-03**	**1.09E-03**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.422**	**0.422 (HCl)**

- = negligible

Note 1: The emission units above are controlled by integral cyclones and dust collectors. See the technical support document of this permit for additional details on the integral control devices at this source. Therefore, the PTE after the control shall be used for permit level determination.

	Uncontrolled PTE (tons/year) of proposed emission units									
Emission Unit	PM (tons/yr)	PM10 (tons/yr)	PM2.5 (tons/yr)	SO_2 (tons/yr)	NOx (tons/yr)	VOC (tons/yr)	CO (tons/yr)	GHGs as CO2e (tons/yr)	Total HAPs (tons/yr)	Worst Single HAPs (tons/yr)
BB-1, BD-4, BD-5, BD-6, BD-7 and BD-8 from combustion	0.21	0.84	0.84	0.07	10.99	0.60	9.23	13,272.85	0.207	0.198 (Hexane)
BD-4, BD-5, BD-6, BD-7 and BD-8 from drying	5.54E-03	1.39E-02	2.37E-03	-	-	-	-	-	-	-
T-211	-	-	-	-	-	-	-	-	0.329	0.329 (HCl)
[1] new material processing system (tanks, hoppers, conveyors, bagging areas)	2.67E-04	4.34E-04	4.34E-04	-	-	-	-	-	-	-
Total PTE of new units	**0.21**	**0.85**	**0.84**	**0.07**	**10.99**	**0.60**	**9.23**	**13,272.85**	**0.54**	**0.198 (Hexane) and 0.329 (HCl)**

- = negligible

Note 1: The emission units above are controlled by integral cyclones and dust collectors. See the technical support document of this permit for additional details on the integral control devices at this source. Therefore, the PTE after the control shall be used for permit level determination.

	Uncontrolled PTE (tons/year) of source									
Emission Unit	PM (tons/yr)	PM10 (tons/yr)	PM2.5 (tons/yr)	SO_2 (tons/yr)	NOx (tons/yr)	VOC (tons/yr)	CO (tons/yr)	GHGs as CO2e (tons/yr)	Total HAPs (tons/yr)	Worst Single HAPs (tons/yr)
HB-1, HB-2, PD-1 and R&D pilot dryer from combustion	0.20	0.78	0.78	0.06	10.29	0.57	8.65	12,426.77	0.19	0.177 (Hexane)
[1]PD-1 from drying	1.11E-03	2.77E-03	4.73E-04	-	-	-	-	-	-	-
T-122	-	-	-	-	-	-	-	-	0.108	0.108 (HCl)
T-122B	-	-	-	-	-	-	-	-	0.198	0.198 (HCl)
R-156	-	-	-	-	-	-	-	-	0.065	0.065 (HCl)
R-104	-	-	-	-	-	-	-	-	0.052	0.052 (HCl)
[1]existing material processing system (tanks, hoppers, shaker screen, silos, conveyors, bucket elevators)	7.14E-04	1.09E-03	1.09E-03	-	-	-	-	-	-	-
BB-1, BD-4, BD-5, BD-6, BD-7 and BD-8 from combustion	0.21	0.84	0.84	0.07	10.99	0.60	9.23	13,272.85	0.21	0.198 (Hexane)
BD-4, BD-5, BD-6, BD-7 and BD-8 from drying	5.54E-03	1.39E-02	2.37E-03	-	-	-	-	-	-	-
T-211	-	-	-	-	-	-	-	-	0.329	0.329 (HCl)
[1] new material processing system (tanks, hoppers, conveyors, bagging areas)	2.67E-04	4.34E-04	4.34E-04	-	-	-	-	-	-	-
Paved Roads	0.35	0.07	0.02	-	-	-	-	-	-	-
Total PTE of Entire Source	**0.77**	**1.71**	**1.64**	**0.13**	**21.29**	**1.17**	**17.88**	**25,699.62**	**1.15**	**0.375 (Hexane) and 0.751 (HCl)**

- = negligible

Note 1: The emission units above are controlled by integral cyclones and dust collectors. See the technical support document of this permit for additional details on the integral control devices at this source. Therefore, the PTE after the control shall be used for permit level determination.

Appendix A: Emissions Calculations
Natural Gas Combustion Only
MM BTU/HR <100

Company Name: **Micronutrients, A Division of Heritage Technologies, LLC**
Address City IN Zip: **1550 Research Way, Indianapolis, Indiana, 46231**
Permit Number: **097-30945-00417**
Reviewer: **Sarah Street**
Date: **10/11/2011**

Natural gas-fired combustion units		
Unit descripton	Unit number	MMBtu/hr
scotch boiler	HB-1	8.40
scotch boiler	HB-2	12.60
production dryer	PD-1	1.50
R&D pilot dryer	PD-2	1.00
		23.50

Heat Input Capacity MMBtu/hr	Potential Throughput MMCF/yr
23.50	205.9

Total for all natural gas-fired emission units

	Pollutant						
	PM*	PM10*	PM2.5	SO2	NOx	VOC	CO
Emission Factor in lb/MMCF	1.9	7.6	7.6	0.6	100 **see below	5.5	84
Potential Emission in tons/yr	0.20	0.78	0.78	0.06	10.29	0.57	8.65

*PM emission factor is filterable PM only. PM10 emission factor is filterable and condensable PM10 combined. PM2.5 is assumed to be equal to PM10.
**Emission Factors for NOx: Uncontrolled = 100, Low NOx Burner = 50, Low NOx Burners/Flue gas recirculation = 32

Methodology
All emission factors are based on normal firing.
MMBtu = 1,000,000 Btu
MMCF = 1,000,000 Cubic Feet of Gas
Emission Factors are from AP 42, Chapter 1.4, Tables 1.4-1, 1.4-2, 1.4-3, SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03
Potential Throughput (MMCF) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMCF/1,000 MMBtu
Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton

See next page for HAPs emissions calculations.

Appendix A: Emissions Calculations
Natural Gas Combustion Only
MM BTU/HR <100
HAPs Emissions

Company Name: **Micronutrients, A Division of Heritage Technologies, LLC**
Address City IN Zip: **1550 Research Way, Indianapolis, Indiana, 46231**
Permit Number: **097-30945-00417**
Reviewer: **Sarah Street**
Date: **10/11/2011**

	HAPs - Organics				
	Benzene	Dichlorobenzene	Formaldehyde	Hexane	Toluene
Emission Factor in lb/MMcf	2.1E-03	1.2E-03	7.5E-02	1.8E+00	3.4E-03
Potential Emission in tons/yr	2.16E-04	1.24E-04	0.008	0.185	3.50E-04

	HAPs - Metals					
	Lead	Cadmium	Chromium	Manganese	Nickel	
Emission Factor in lb/MMcf	5.0E-04	1.1E-03	1.4E-03	3.8E-04	2.1E-03	Total
Potential Emission in tons/yr	5.15E-05	1.13E-04	1.44E-04	3.91E-05	2.16E-04	0.194

Methodology is the same the previous page.

The five highest organic and metal HAPs emission factors are provided above.
Additional HAPs emission factors are available in AP-42, Chapter 1.4.

Appendix A: Emissions Calculations
Natural Gas Combustion Only
MM BTU/HR <100
Greenhouse Gas Emissions

Company Name: **Micronutrients, A Division of Heritage Technologies, LLC**
Address City IN Zip: **1550 Research Way, Indianapolis, Indiana, 46231**
Permit Number: **097-30945-00417**
Reviewer: **Sarah Street**
Date: **10/11/2011**

	Greenhouse Gas		
	CO_2	CH_4	N_2O
Emission Factor in lb/MMcf	120,000	2.3	2.2
Potential Emission in tons/yr	12,351.60	0.24	0.23
Summed Potential Emissions in tons/yr		12,352.06	
CO_2e Total in tons/yr		12,426.77	

Methodology

The N2O Emission Factor for uncontrolled is 2.2. The N2O Emission Factor for low Nox burner is 0.64.
Emission Factors are from AP 42, Table 1.4-2 SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03.
Greenhouse Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton

CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (21) + N2O Potential Emission ton/yr x N2O GWP (310).

Appendix A: Emissions Calculations
Natural Gas Combustion Only
MM BTU/HR <100

Company Name: **Micronutrients, A Division of Heritage Technologies, LLC**
Address City IN Zip: **1550 Research Way, Indianapolis, Indiana, 46231**
Permit Number: **097-30945-00417**
Reviewer: **Sarah Street**
Date: **10/11/2011**

Natural gas-fired combustion units		
Unit descripton	Unit number	MMBtu/hr
steam generator	BB-1	12.60
plant dryer system	BD-4	2.50
plant dryer system	BD-5	2.50
plant dryer system	BD-6	2.50
plant dryer system	BD-7	2.50
plant dryer system	BD-8	2.50
		25.10

Heat Input Capacity MMBtu/hr	Potential Throughput MMCF/yr
25.10	219.9

Total for all natural gas-fired emission units

	Pollutant						
	PM*	PM10*	PM2.5	SO2	NOx	VOC	CO
Emission Factor in lb/MMCF	1.9	7.6	7.6	0.6	100 **see below	5.5	84
Potential Emission in tons/yr	0.21	0.84	0.84	0.07	10.99	0.60	9.23

*PM emission factor is filterable PM only. PM10 emission factor is filterable and condensable PM10 combined. PM2.5 is assumed to be equal to PM10.
**Emission Factors for NOx: Uncontrolled = 100, Low NOx Burner = 50, Low NOx Burners/Flue gas recirculation = 32

Methodology
All emission factors are based on normal firing.
MMBtu = 1,000,000 Btu
MMCF = 1,000,000 Cubic Feet of Gas
Emission Factors are from AP 42, Chapter 1.4, Tables 1.4-1, 1.4-2, 1.4-3, SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03
Potential Throughput (MMCF) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMCF/1,000 MMBtu
Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton

See next page for HAPs emissions calculations.

Appendix A: Emissions Calculations
Natural Gas Combustion Only
MM BTU/HR <100
HAPs Emissions

Company Name: **Micronutrients, A Division of Heritage Technologies, LLC**
Address City IN Zip: **1550 Research Way, Indianapolis, Indiana, 46231**
Permit Number: **097-30945-00417**
Reviewer: **Sarah Street**
Date: **10/11/2011**

	HAPs - Organics				
	Benzene	Dichlorobenzene	Formaldehyde	Hexane	Toluene
Emission Factor in lb/MMcf	2.1E-03	1.2E-03	7.5E-02	1.8E+00	3.4E-03
Potential Emission in tons/yr	2.31E-04	1.32E-04	0.008	0.198	3.74E-04

	HAPs - Metals					
	Lead	Cadmium	Chromium	Manganese	Nickel	
Emission Factor in lb/MMcf	5.0E-04	1.1E-03	1.4E-03	3.8E-04	2.1E-03	Total
Potential Emission in tons/yr	5.50E-05	1.21E-04	1.54E-04	4.18E-05	2.31E-04	0.207

Methodology is the same the previous page.

The five highest organic and metal HAPs emission factors are provided above.
Additional HAPs emission factors are available in AP-42, Chapter 1.4.

Appendix A: Emissions Calculations
Natural Gas Combustion Only
MM BTU/HR <100
Greenhouse Gas Emissions

Company Name: **Micronutrients, A Division of Heritage Technologies, LLC**
Address City IN Zip: **1550 Research Way, Indianapolis, Indiana, 46231**
Permit Number: **097-30945-00417**
Reviewer: **Sarah Street**
Date: **10/11/2011**

	Greenhouse Gas		
	CO2	CH4	N2O
Emission Factor in lb/MMcf	120,000	2.3	2.2
Potential Emission in tons/yr	13,192.56	0.25	0.24
Summed Potential Emissions in tons/yr		13,193.05	
CO2e Total in tons/yr		13,272.85	

Methodology

The N2O Emission Factor for uncontrolled is 2.2. The N2O Emission Factor for low Nox burner is 0.64.
Emission Factors are from AP 42, Table 1.4-2 SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03.
Greenhouse Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton

CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (21) + N2O Potential Emission ton/yr x N2O GWP (310).

Appendix A: Emissions Calculations
Particulate Emissions from Drying

Company Name:	**Micronutrients, A Division of Heritage Technologies, LLC**
Address City IN Zip:	**1550 Research Way, Indianapolis, Indiana, 46231**
Permit Number:	**097-30945-00417**
Reviewer:	**Sarah Street**
Date:	**10/11/2011**

AP-42 Table 9.9.1-1 reference	Process	Emission Factor (lbs/ton)*		
		PM	PM10	PM2.5
3-02-005-27	Column dryer	0.22	0.0550	0.0094

Filter Unit Control Efficiency		
PM	PM10	PM2.5
99.9%	99.0%	99.0%

Potential to Emit (PTE) of Particulate (PM and PM10)

Emission Unit	Emission Factor	Potential Material Throughput (lbs/hr)	Potential Material Throughput (tons/hr)	Uncontrolled PTE of PM (lbs/hour)	Uncontrolled PTE of PM10 (lbs/hour)	Uncontrolled PTE of PM2.5 (lbs/hour)	Uncontrolled PTE of PM (tons/yr)	Uncontrolled PTE of PM10 (tons/yr)	Uncontrolled PTE of PM2.5 (tons/yr)	**Controlled PTE of PM (tons/yr)	**Controlled PTE of PM10 (tons/yr)	**Controlled PTE of PM2.5 (tons/yr)
PD-1	3-02-005-27	2300.0	1.15	0.25	0.06	0.01	1.11	0.28	0.05	1.11E-03	2.77E-03	4.73E-04
						Total Existing	**1.11**	**0.28**	**0.05**	**1.11E-03**	**2.77E-03**	**4.73E-04**
BD-4	3-02-005-27	2300.0	1.15	0.25	0.06	0.01	1.11	0.28	0.05	1.11E-03	2.77E-03	4.73E-04
BD-5	3-02-005-27	2300.0	1.15	0.25	0.06	0.01	1.11	0.28	0.05	1.11E-03	2.77E-03	4.73E-04
BD-6	3-02-005-27	2300.0	1.15	0.25	0.06	0.01	1.11	0.28	0.05	1.11E-03	2.77E-03	4.73E-04
BD-7	3-02-005-27	2300.0	1.15	0.25	0.06	0.01	1.11	0.28	0.05	1.11E-03	2.77E-03	4.73E-04
BD-8	3-02-005-27	2300.0	1.15	0.25	0.06	0.01	1.11	0.28	0.05	1.11E-03	2.77E-03	4.73E-04
						Total New	**5.54**	**1.39**	**0.24**	**5.54E-03**	**1.39E-02**	**2.37E-03**

Methodology

* Since there are no emission factors for drying animal feed, emission factors used are from AP-42 Table 9.9.1-1 for grain elevators, column dryer 3-02-005-27.

**The existing emission units above are controlled by integral cyclones and dust collectors. See the technical support document of this permit for additional details on the integral control devices at this source. Therefore, the PTE after the control shall be used for permit level determination.

Maximum Hourly Throughput (tons/hr) = [Maximum Hourly Throughput (lbs/hr)] / [2000 lbs/ton]
Uncontrolled PTE of PM or PM10 (lbs/hour) = [Maximum Hourly Throughput (tons/hr)] * [Emission Factor (lbs/ton)]
Uncontrolled PTE of PM or PM10 (tons/year) = [Uncontrolled PTE of PM or PM10 (lbs/hour)] * [8760 hours/year)] / [2000 lbs/ton]
Controlled PTE of PM or PM10 (tons/year) = [Uncontrolled PTE of PM or PM10 (tons/year)] *[1 - Control Efficiency]

Compliance with 326 IAC 6-3-2

Emission Unit Type	Emission Factor	Maximum process weight rate (lbs/hr)	Maximum process weight rate (tons/hr)	326 IAC 6-3-2 Allowable PM Emission Rate (lbs/hr)	Emission factor (lb/ton)	Max PTE Particulate (lb/hour)
PD-1	3-02-005-27	2300.0	1.15	4.50	0.220	0.25
BD-4	3-02-005-27	2300.0	1.15	4.50	0.220	0.25
BD-5	3-02-005-27	2300.0	1.15	4.50	0.220	0.25
BD-6	3-02-005-27	2300.0	1.15	4.50	0.220	0.25
BD-7	3-02-005-27	2300.0	1.15	4.50	0.220	0.25
BD-8	3-02-005-27	2300.0	1.15	4.50	0.220	0.25

Appendix A: Emissions Calculations
Emissions from Material Storage, Conveying and Loading

Company Name: Micronutrients, A Division of Heritage Technologies, LLC
Address City IN Zip: 1550 Research Way, Indianapolis, Indiana, 46231
Permit Number: 097-30945-00417
Reviewer: Sarah Street
Date: 10/11/2011

AP-42 Table 9.9.1-2 reference	Process	Emission Factor (lbs/ton)* PM	PM10	PM2.5
3-02-008-02	Grain Receiving	0.017	0.0025	0.0025
3-02-008-03	Feed Shipping	0.0033	0.0008	0.0008

Filter Unit Control Efficiency PM	PM10	PM2.5
99.9%	99.0%	99.0%

Potential to Emit (PTE) of Particulate (PM and PM10)

Emission Unit	Emission Factor	Potential Material Throughput (lbs/hr)**	Potential Material Throughput (tons/hr)**	Uncontrolled PTE of PM (lbs/hour)	Uncontrolled PTE of PM10 (lbs/hour)	Uncontrolled PTE of PM2.5 (lbs/hour)	Uncontrolled PTE of PM (tons/yr)	Uncontrolled PTE of PM10 (tons/yr)	Uncontrolled PTE of PM2.5 (tons/yr)	***Controlled PTE of PM (tons/yr)	***Controlled PTE of PM10 (tons/yr)	***Controlled PTE of PM2.5 (tons/yr)
Bucket Elevator	3-02-008-02	6000.0	3.00	0.05	0.01	0.01	0.22	0.03	0.03	2.2E-04	3.3E-04	3.3E-04
Bucket Elevator	3-02-008-02	6000.0	3.00	0.05	0.01	0.01	0.22	0.03	0.03	2.2E-04	3.3E-04	3.3E-04
Bucket Elevator	3-02-008-02	6000.0	3.00	0.05	0.01	0.01	0.22	0.03	0.03	2.2E-04	3.3E-04	3.3E-04
Packaging	3-02-008-03	6000.0	3.00	9.90E-03	2.40E-03	0.00	0.04	0.01	0.01	4.3E-05	1.1E-04	1.1E-04
						Totals	**0.71**	**0.11**	**0.11**	**7.14E-04**	**1.09E-03**	**1.09E-03**

Methodology

* Emission Factors from AP-42 Table 9.9.1-2 for Animal feed mills, grain receiving 3-02-008-02, and feed shipping 3-02-008-03.

** The source indicated that the Potential Material Throughput (tons/hr) of 3 tons per hour is more than the existing line could process based on operational bottlenecks including cleaning steps that require the process to be shutdown. However, since the maximum potential throughput has been used for the PTE, additional information on the bottleneck was not requested.

***The existing emission units above are controlled by integral cyclones and dust collectors. See the technical support document of this permit for additional details on the integral control devices at this source. Therefore, the PTE after the control shall be used for permit level determination.

Maximum Hourly Throughput (tons/hr) = [Maximum Hourly Throughput (lbs/hr)] / [2000 lbs/ton]
Uncontrolled PTE of PM or PM10 (lbs/hour) = [Maximum Hourly Throughput (tons/hr)] * [Emission Factor (lbs/ton)]
Uncontrolled PTE of PM or PM10 (tons/year) = [Uncontrolled PTE of PM or PM10 (lbs/hour)] * [8760 hours/year)] / [2000 lbs/ton]
Controlled PTE of PM or PM10 (tons/year) = [Uncontrolled PTE of PM or PM10 (tons/year)] *[1 - Control Efficiency]

Compliance with 326 IAC 6-3-2

Emission Unit Type	Emission Factor	Maximum process weight rate (lbs/hr)	Maximum process weight rate (tons/hr)	326 IAC 6-3-2 Allowable PM Emission Rate (lbs/hr)	Emission factor (lb/ton)	Max PTE Particulate (lb/hour)
Bucket Elevator	3-02-008-02	6000.0	3.00	8.56	0.017	0.05
Bucket Elevator	3-02-008-02	6000.0	3.00	8.56	0.017	0.05
Bucket Elevator	3-02-008-02	6000.0	3.00	8.56	0.017	0.05
Packaging	3-02-008-03	6000.0	3.00	8.56	0.0033	0.01

Appendix A: Emissions Calculations
Emissions from Material Storage, Conveying and Loading

Company Name: Micronutrients, A Division of Heritage Technologies, LLC
Address City IN Zip: 1550 Research Way, Indianapolis, Indiana, 46231
Permit Number: 097-30945-00417
Reviewer: Sarah Street
Date: 10/11/2011

AP-42 Table 9.9.1-2 reference	Process	Emission Factor (lbs/ton)* PM	PM10	PM2.5
3-02-008-02	Grain Receiving	0.017	0.00	0.00
3-02-008-03	Feed Shipping	0.0033	0.0008	0.0008

Filter Unit Control Efficiency PM	PM10	PM2.5
99.9%	99.0%	99.0%

Potential to Emit (PTE) of Particulate (PM and PM10)

Emission Unit	Emission Factor	Potential Material Throughput (lbs/hr)**	Potential Material Throughput (tons/hr)	Uncontrolled PTE of PM (lbs/hour)	Uncontrolled PTE of PM10 (lbs/hour)	Uncontrolled PTE of PM2.5 (lbs/hour)	Uncontrolled PTE of PM (tons/yr)	Uncontrolled PTE of PM10 (tons/yr)	Uncontrolled PTE of PM2.5 (tons/yr)	Controlled PTE of PM (tons/yr)	Controlled PTE of PM10 (tons/yr)	Controlled PTE of PM10 (tons/yr)
Dump hopper	3-02-008-02	2000.0	1.00	1.70E-02	2.50E-03	2.50E-03	0.07	0.01	0.01	7.4E-05	1.1E-04	1.1E-04
Dump hopper	3-02-008-02	2000.0	1.00	1.70E-02	2.50E-03	2.50E-03	0.07	0.01	0.01	7.4E-05	1.1E-04	1.1E-04
Dump hopper	3-02-008-02	2000.0	1.00	1.70E-02	2.50E-03	2.50E-03	0.07	0.01	0.01	7.4E-05	1.1E-04	1.1E-04
Bagging area	3-02-008-03	2000.0	1.00	3.30E-03	8.00E-04	0.00	1.45E-02	3.50E-03	3.50E-03	1.4E-05	3.5E-05	3.5E-05
Bagging area	3-02-008-03	2000.0	1.00	3.30E-03	8.00E-04	0.00	1.45E-02	3.50E-03	3.50E-03	1.4E-05	3.5E-05	3.5E-05
Bagging area	3-02-008-03	2000.0	1.00	3.30E-03	8.00E-04	0.00	1.45E-02	3.50E-03	3.50E-03	1.4E-05	3.5E-05	3.5E-05
						Totals	**0.27**	**0.04**	**0.04**	**2.7E-04**	**4.3E-04**	**4.3E-04**

Methodology

* Emission Factors from AP-42 Table 9.9.1-2 for Animal feed mills, grain receiving 3-02-008-02, and feed shipping 3-02-008-03.

** The source indicated that the Potential Material Throughput (tons/hr) of 1 tons per hour is more than the existing line could process based on operational bottlenecks including cleaning steps that require the process to be shutdown. However, since the maximum potential throughput has been used for the PTE, additional information on the bottleneck was not requested.

***The existing emission units above are controlled by integral cyclones and dust collectors. See the technical support document of this permit for additional details on the integral control devices at this source. Therefore, the PTE after the control shall be used for permit level determination.

Maximum Hourly Throughput (tons/hr) = [Maximum Hourly Throughput (lbs/hr)] / [2000 lbs/ton]
Uncontrolled PTE of PM or PM10 (lbs/hour) = [Maximum Hourly Throughput (tons/hr)] * [Emission Factor (lbs/ton)]
Uncontrolled PTE of PM or PM10 (tons/year) = [Uncontrolled PTE of PM or PM10 (lbs/hour)] * [8760 hours/year)] / [2000 lbs/ton]
Controlled PTE of PM or PM10 (tons/year) = [Uncontrolled PTE of PM or PM10 (tons/year)] *[1 - Control Efficiency)]

Compliance with 326 IAC 6-3-2

Emission Unit Type	Emission Factor	Maximum process weight rate (lbs/hr)	Maximum process weight rate (tons/hr)	326 IAC 6-3-2 Allowable PM Emission Rate (lbs/hr)	Emission factor (lb/ton)	Max PTE Particulate (lb/hour)
Dump hopper	3-02-008-02	2000.0	1.00	4.10	0.017	0.017
Dump hopper	3-02-008-02	2000.0	1.00	4.10	0.017	0.017
Dump hopper	3-02-008-02	2000.0	1.00	4.10	0.017	0.017
Bagging area	3-02-008-03	2000.0	1.00	4.10	0.0033	0.003
Bagging area	3-02-008-03	2000.0	1.00	4.10	0.0033	0.003
Bagging area	3-02-008-03	2000.0	1.00	4.10	0.0033	0.003

Appendix A: Emission Calculations
HCl Emissions
From Tanks

Company Name: **Micronutrients, A Division of Heritage Technologies, LLC**
Address City IN Zip: **1550 Research Way, Indianapolis, Indiana, 46231**
Permit Number: **097-30945-00417**
Reviewer: **Sarah Street**
Date: **10/11/2011**

Unit ID	Emission Unit Description	Year of Construction	Control Device	Maximum Capacity (gal)	Net Throughput (gal/yr)	PTE of HCl (lbs/yr)*	PTE of HCl (tons/yr)
T-122	Hydrochloric Acid Receiving Tank, located at the Plant	1994	None	5,137	441,782	215.11	0.11
T-122B	Hydrochloric Acid Receiving Tank, located at the Plant	2005	None	10,846	932,756	395.68	0.20
R-156	Hydrochloric Acid Process Tank, located at the Plant	2008	PS-2	4,889	885,340	129.68	0.06
R-104	Hydrochloric Acid Process Tank, located at the Plant	2008	PS-2	2,760	489,197	103.19	0.05
T-211	Hydrochloric Acid Receiving Tank, located at the BTMP Plant	2011	BS-4	19,807	1,980,650	657.54	0.33
					Total	**1,501.20**	**0.75**

* Emissions from the tanks were calculated by the Permittee using EPA TANKS software (version 4.09d) and have been verified.
PTE is calculated as uncontrolled

METHODOLOGY
PTE of VOC (tons/yr) = PTE of VOC (lbs/yr/uni) x Number of Units x 1 ton/2000 lbs

Appendix A: Emission Calculations
Fugitive Dust Emissions - Paved Roads

Company Name: Micronutrients, A Division of Heritage Technologies, LLC
Address City IN Zip: 1550 Research Way, Indianapolis, Indiana, 46231
Permit Number: 097-30945-00417
Reviewer: Sarah Street
Date: 10/11/2011

Paved Roads at Industrial Site

The following calculations determine the amount of emissions created by paved roads, based on 8,760 hours of use and AP-42, Ch 13.2.1 (12/2003).

[1]Vehicle Informtation (conservative assumptions by IDEM)

Type	Maximum number of vehicles per day	Number of one-way trips per day per vehicle	Maximum trips per day (trip/day)	Maximum Weight Loaded (tons/trip)	Total Weight driven per day (ton/day)	Maximum one-way distance (feet/trip)	Maximum one-way distance (mi/trip)	Maximum one-way miles (miles/day)	Maximum one-way miles (miles/yr)
Passenger Vehicles entering plants	50.0	1.0	50.0	2.5	125.0	1500	0.284	14.2	5184.7
PassengerVehicle leaving plants	50.0	1.0	50.0	2.5	125.0	1500	0.284	14.2	5184.7
Truck entering plants	20.0	1.0	20.0	13.0	260.0	1500	0.284	5.7	2073.9
Truck leaving plants	20.0	1.0	20.0	22.0	440.0	1500	0.284	5.7	2073.9
		Total	**140.0**		**950.0**			**39.8**	**14517.0**

Note 1: The source did not provide vehicle information for the registration. Therefore, IDEM made conservative assumptions for passengar vehicles and trucks to estimate the PTE particulate from roads.

Average Vehicle Weight Per Trip = 6.8 tons/trip
Average Miles Per Trip = 0.28 miles/trip

Unmitigated Emission Factor, Ef = [k * (sL)^0.91 * (W)^1.02] (Equation 1 from AP-42 13.2.1.3 (01/2011)

	PM	PM10	PM2.5	
where k =	0.011	0.0022	0.00054	lb/VMT = particle size multiplier (AP-42 Table 13.2.1-1)
W =	6.8	6.8	6.8	tons = average vehicle weight (provided by source)
sL =	0.6	0.6	0.6	g/m^2 = Ubitiguous Baseline Silt Loading Values of paved roads (Table 13.2.1-2)

Taking natural mitigation due to precipitation into consideration, Mitigated Emission Factor, Eext = E * [1 - (p/4N)]

Mitigated Emission Factor, Eext = Ef * [1 - (p/4N)]
where p = 125 days of rain greater than or equal to 0.01 inches (see Fig. 13.2.1-2)
N = 365 days per year

	PM	PM10	PM2.5	
Unmitigated Emission Factor, Ef =	0.05	0.01	0.00	lb/mile
Mitigated Emission Factor, Eext =	0.04	0.01	0.00	lb/mile

Process	Unmitigated PTE of PM (tons/yr)	Unmitigated PTE of PM10 (tons/yr)	Unmitigated PTE of PM2.5 (tons/yr)	Mitigated PTE of PM (tons/yr)	Mitigated PTE of PM10 (tons/yr)	Mitigated PTE of PM2.5 (tons/yr)
Passenger Vehicles entering plants	0.13	0.03	0.01	0.12	0.02	0.01
PassengerVehicle leaving plants	0.13	0.03	0.01	0.12	0.02	0.01
Truck entering plants	0.05	0.01	0.00	0.05	0.01	0.00
Truck leaving plants	0.05	0.01	0.00	0.05	0.01	0.00
	0.35	**0.07**	**0.02**	**0.32**	**0.06**	**0.02**

Methodology

Total Weight driven per day (ton/day) = [Maximum Weight Loaded (tons/trip)] * [Maximum trips per day (trip/day)]
Maximum one-way distance (mi/trip) = [Maximum one-way distance (feet/trip) / [5280 ft/mile]
Maximum one-way miles (miles/day) = [Maximum trips per year (trip/day)] * [Maximum one-way distance (mi/trip)]
Average Vehicle Weight Per Trip (ton/trip) = SUM[Total Weight driven per day (ton/day)] / SUM[Maximum trips per day (trip/day)]
Average Miles Per Trip (miles/trip) = SUM[Maximum one-way miles (miles/day)] / SUM[Maximum trips per year (trip/day)]
Unmitigated PTE (tons/yr) = [Maximum one-way miles (miles/yr)] * [Unmitigated Emission Factor (lb/mile)] * (ton/2000 lbs)
Mitigated PTE (tons/yr) = [Maximum one-way miles (miles/yr)] * [Mitigated Emission Factor (lb/mile)] * (ton/2000 lbs)
Controlled PTE (tons/yr) = [Mitigated PTE (tons/yr)] * [1 - Dust Control Efficiency]

Abbreviations

PM = Particulate Matter
PM10 = Particulate Matter (<10 um)
PM2.5 = Particle Matter (<2.5 um)
PTE = Potential to Emit

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

We Protect Hoosiers and Our Environment.

Mitchell E. Daniels Jr.
Governor

Thomas W. Easterly
Commissioner

100 North Senate Avenue
Indianapolis, Indiana 46204
(317) 232-8603
Toll Free (800) 451-6027
www.idem.IN.gov

SENT VIA U.S. MAIL: CONFIRMED DELIVERY AND SIGNATURE REQUESTED

TO: Brian Wilson
Micronutrients, Division of Heritage Technologies, LLC
1550 Research Way
Indianapolis, IN 46231

DATE: November 22, 2011

FROM: Matt Stuckey, Branch Chief
Permits Branch
Office of Air Quality

SUBJECT: Final Decision
Registration
097-30945-00417

Enclosed is the final decision and supporting materials for the air permit application referenced above. Please note that this packet contains the original, signed, permit documents.

The final decision is being sent to you because our records indicate that you are the contact person for this application. However, if you are not the appropriate person within your company to receive this document, please forward it to the correct person.

A copy of the final decision and supporting materials has also been sent via standard mail to:
Theodore Moore, Jr. (Vice President)
OAQ Permits Branch Interested Parties List

If you have technical questions regarding the enclosed documents, please contact the Office of Air Quality, Permits Branch at (317) 233-0178, or toll-free at 1-800-451-6027 (ext. 3-0178), and ask to speak to the permit reviewer who prepared the permit. If you think you have received this document in error, please contact Joanne Smiddie-Brush of my staff at 1-800-451-6027 (ext 3-0185), or via e-mail at jbrush@idem.IN.gov.

Final Applicant Cover letter.dot 11/30/07

Mail Code 61-53

IDEM Staff	MIDENNEY 11/22/2011 Micronutrients, Division of Heritage Technologies, LLC 097-30945-00417 (final)			AFFIX STAMP HERE IF USED AS CERTIFICATE OF MAILING
Name and address of Sender	▶	Indiana Department of Environmental Management Office of Air Quality – Permits Branch 100 N. Senate Indianapolis, IN 46204	Type of Mail: **CERTIFICATE OF MAILING ONLY**	

Line	Article Number	Name, Address, Street and Post Office Address	Postage	Handing Charges	Act. Value (If Registered)	Insured Value	Due Send if COD	R.R. Fee	S.D. Fee	S.H. Fee	Rest. Del. Fee Remarks
1		Brian Wilson Micronutrients, Division of Heritage Technologies, 1550 Research Way Indianapolis IN 46231 (Source CAATS) via confirm delivery									
2		Theodore B Moore Jr VP Micronutrients, Division of Heritage Technologies, 1550 Research Way Indianapolis IN 46231 *(RO CAATS)*									
3		Marion County Health Department 3838 N, Rural St Indianapolis IN 46205-2930 *(Health Department)*									
4		Mrs. Sandra Lee Watson 7834 E 100 S Marion IN 46953 *(Affected Party)*									
5		Indianapolis City Council and Mayors Office 200 East Washington Street, Room E Indianapolis IN 46204 *(Local Official)*									
6		Marion County Commissioners 200 E. Washington St. City County Bldg., Suite 801 Indianapolis IN 46204 *(Local Official)*									
7		Matt Mosier Office of Sustainability 1200 S Madison Ave #200 Indianapolis IN 46225 *(Local Official)*									
8		Mark Zeltwanger 26545 CR 52 Nappanee IN 46550 *(Affected Party)*									
9											
10											
11											
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