Great Western Malting Co.

RECEIVED

DEC 07 2015

DEPARTMENT OF ENVIRONMENTAL QUALITY
STATE A Q PROGRAM

√# 162307
1000.00 YC
Wet Sign. Rec'd -

P.O. Box 1529
Vancouver, WA 98668-1529

December 3, 2015

Air Quality Program Office-Application Processing
Department of Environmental Quality
1410 N. Hilton
Boise, Idaho 83706-1255

Subject: Great Western Malting Pocatello Plant ID No. 005-00035
Pre-Permit Construction Approval and PTC Application

Dear Application Processing Manager:

Great Western Malting Co. is submitting the enclosed Permit to Construct (PTC) application for a planned expansion of the Pocatello plant. In addition, we are requesting the ability to construct the expansion project under the Pre-Permit Construction regulations [IDPA 58.01.01.213] before obtaining the required permit to construct. The information in this application supersedes the information in prior PTC application dated November 9, 2015.

Transmitted with this letter are:

1. 1 hard copy and 1 electronic copy of the Permit to Construct application dated December 3, 2015 that contains our proof of eligibility as a minor source, process descriptions, equipment lists and forms, modeled ambient concentrations of regulated pollutants and toxic air pollutants, and proposed emission limits.
2. A copy of the written modeling protocol and written Department approval (Section 7 of the application)
3. A copy of the notice published in the Pocatello paper for the public information meeting about the project
4. A check in the amount of $1,000 for the application fee

In the application we have proposed emissions limits, operational restrictions and monitoring in order to limit the potential to emit from the facility as required by the Pre-Permit Construction regulations [IDPA 58.01.01.213.01.d]. These proposed restrictions are presented in Section 5.3 of the application and are certified by our official's signature on the General Information Form GI in Section 1 of the application.

We look forward to hearing from the Department during the 15-day Pre-Permit Construction review. Please contact Jay Hamachek at (360) 699-6785 or at jay.hamachek@greatwesternmalting.com if you have questions about our submittal.

Sincerely,

GREAT WESTERN MALTING CO.

Jay W Hamachek
Global Director of Compliance & Corporate Social Responsibility

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DEC 07 2015

DEPARTMENT OF ENVIRONMENTAL QUALITY
STATE A Q PROGRAM

BRIDGEWATER GROUP, INC.

TRANSMITTAL

To: Air Quality Program Office
Department of Environmental Quality
1410 N. Hilton
Boise, Idaho 83706-1255

From: Candice Hatch

Attn: Application Processing

Date: **December 3, 2015**

Re: Great Western Malting Co. (Facility ID No. 005-00035)

We Are Sending You:

X	Attached		Under separate cover via	
	Shop Drawings	X	Documents	Tracings
	Prints		Specifications	Catalogs
	Copy of letter		Other:	

Quantity	Description
1	December 3, 2015 Letter from GWM requesting Pre-Permit Construction Approval (located inside PTC application binder cover)
1	Copy of Pubilc Meeting Notice (located inside binder cover)
1	Check for Application Fee in the amount of $1,000.00 (located inside binder cover)
1	Hard copy of the PTC Application dated 12/3/2015
1	Electronic copy of the PTC Application and modeling files (Section 8 of application)

Remarks:

If material received is not as listed, please notify us at once at (503) 675-0904.
Candice Hatch

Great Western Malting Pocatello Expansion

Copy of notice to be published in Idaho State Journal on 12/5/2015

Notice of Public Informational Meeting December 17, 2015

Great Western Malting Co. (GWM) is holding a public informational meeting to discuss the planned expansion of the Pocatello plant and how the expansion will comply with air permitting regulations. GWM has been producing malt in Pocatello since 1980 using local Idaho grown barley. The expansion of GWM's existing plant will more than double the current production capacity.

The plant processes barley and other grains into malt for the brewing, distilling and food industries. Malting involves the intake of grains, cleaning/storing of the grain, steeping the grain in water, germination of the grain, kiln drying of the grain, cleaning and shipping of the malt.

Great Western Malting is applying to Idaho DEQ for a modification to its air permit and requesting that pre-permit construction approval be granted. Pre-permit construction approval will allow construction to begin before the modified air permit is issued. This topic will be discussed in more detail at the meeting.

The expanded plant will not operate until the Idaho DEQ issues the modified air Permit to Construct in accordance with their procedures for issuing of permits, including an opportunity for public input.

The meeting will be held at the Hampton Inn located at 151 Vista Dr, Pocatello, ID 83201, on Thursday December 17, 2015, 2015 at 9am. The meeting site is accessible to persons with disabilities. Requests for accommodation must be made no later than five (5) days prior to the meeting.

Pre-Permit Construction Approval and Application to Modify the Permit to Construct

(Permit No. P-060312)

Expansion of Malt Processing at the Great Western Malting Pocatello Plant

(Facility ID No. 005-00035)

Submitted to:

Idaho Department of Environmental Quality

Submitted by:

Great Western Malting Co.

December 3, 2015

CONTENTS

Section	***Page***

Appendix

Tables **Page**

1.0 Application Forms

1.1 Checklists

This section contains these application checklists:

- 15-Day Pre-Permit Construction Application Completeness Checklist
- Toxic Air Pollutant (TAP) Preconstruction Compliance Application Checklist
- Dispersion Modeling Protocol Checklist

Department of Environmental Quality
1410 N. Hilton, Boise, ID 83706
For assistance, call the
Air Permit Hotline - 1-877-5PERMIT

15- Day Pre-Permit Construction Approval Application Completeness Checklist

This checklist is designed to aid the applicant in submitting a complete pre-permit construction approval application. In addition to the items in this checklist, information requested by DEQ during review of the application should be provided in accordance with IDAPA 58.01.01.202.03, or the application may be denied.

I. Actions Needed Before Submitting Application

☒ Refer to the Rule. Read the Pre-Permit Construction requirements contained in IDAPA 58.01.01.213, Rules for the Control of Air Pollution in Idaho.

☒ Refer to DEQ's Pre-Permit Construction Approval Guidance Document. DEQ has developed a guidance document to aid applicants in submitting a complete pre-permit construction approval application. The guidance document is located on DEQ's website (go to http://www.deq.idaho.gov/air/permits_forms/permitting/ptc_prepermit_guidance.pdf

☒ Consult with DEQ Representatives. Schedule a pre-application meeting with DEQ to discuss application requirements before submitting the pre-permit construction approval application. Schedule the meeting by contacting the DEQ Air Permit Hotline at **877-5PERMIT**. The meeting can be in person or on the phone. Refer to IDAPA 58.01.01.213.01b.

☒ Schedule Informational Meeting. Schedule an informational meeting before submitting the pre-permit construction approval application for the purposes of satisfying IDAPA 58.01.01.213.02.a. The purpose for the informational meeting is to provide information about the proposed project to the general public. Refer to IDAPA 58.01.01.213.01.c.

☒ Submit Ambient Air Quality Modeling Protocol. It is required that an ambient air quality modeling protocol be submitted to DEQ at least two (2) weeks before the pre-permit construction approval application is submitted. Contact DEQ's Air Quality Hotline at **877-5PERMIT** for information about the protocol.

☒ Written DEQ Approved Protocol. Written DEQ approval of the modeling protocol must be received before the pre-permit construction approval application is submitted. Refer to IDAPA 58.01.01.213.01.c.

II. Application Content

Application content should be prepared using the checklist below. The checklist is based on the requirements contained in IDAPA 58.01.01.213 and DEQ's Pre-Permit Construction Approval Guidance Document.

☒ Pre-Permit Construction Eligibility and Proof of Eligibility. Pre-permit construction approval is not available for any new Prevention of Significant Deterioration (PSD) major source, any proposed PSD major modification, or any proposed major NSR project in a non-attainment area. Emissions netting and emissions offsets are not allowed to be used. A certified proof of pre-permit construction eligibility must be submitted with the pre-permit construction approval application. Refer to IDAPA 58.01.01.213.01.

☒ Request to Construct Before Obtaining a Permit to Construct. Letter requesting the ability to construct before obtaining the required permit to construct must be submitted with the pre-permit construction approval application. Refer to IDAPA 58.01.01.213.01.c.

☒ Apply for a Permit to Construct. Submit a Permit to Construct application using forms available on DEQ's website at http://www.deq.idaho.gov. Refer to IDAPA 58.01.01.213.01.a.

☒ Permit to Construct Application Fee. The permit to construct application fee of $1000 must be submitted at the time the original pre-permit construction approval application is submitted. Refer to IDAPA 58.01.01.224. If the pre-permit construction approval is denied and a new application is submitted, a new $1,000 application fee will be required to be submitted. The application fee is not transferable or refundable. The application fee can be paid by check, credit card or Electronic Funds Transfer (EFT). If you choose to pay by credit card or EFT, contact DEQ's Fiscal Office at (208) 373-0502 to complete the necessary paper work. If you choose to pay by check, enclose the check with your pre-permit construction approval application.

☒ Notice of Informational Meeting. Within 10 days after the submittal of the pre-permit construction approval application, an informational meeting must be held in at least one location in the region where the stationary source will be located. The information meeting must be made known by notice published at least 10 days before the informational meeting in a newspaper of general circulation in the county in which the stationary source will be located. A copy of this notice, as published, must be submitted with the pre-permit construction approval application. Refer to IDAPA 58.01.01.213.02.a. Additional information regarding the informational meeting is included in DEQ's Pre-Permit Construction Approval Guidance Document. (go to http://www.deq.idaho.gov/air/permits_forms/permitting/ptc_prepermit_guidance.pdf)

☒ Process Description(s). The process or processes for which pre-permit construction approval is requested must be described in sufficient detail and clarity such that a member of the general public not familiar with air quality can clearly understand the proposed project. A process flow diagram is required for each process for which pre-permit construction approval is requested. Refer to IDAPA 58.01.01.213.01.c.

☒ Equipment List. All equipment that will be used for which pre-permit construction approval is requested must be described in detail. Such description includes, but is not limited to, manufacturer, model number or other descriptor, serial number, maximum process rate, proposed process rate, maximum heat input capacity, stack height, stack diameter, stack gas flowrate, stack gas temperature, etc. All equipment that will be used for which pre-permit construction approval is requested must be clearly labeled on the process flow diagram. Refer to IDAPA 58.01.01.213.01.c.

☒ Scaled Plot Plan. A scaled plot plan is required, with the location of each proposed process and the equipment that will be used in each process clearly labeled.

☒ Schedule for Construction. A schedule for construction is required, including proposed dates for commencement and for completion of the project. For phased projects, proposed dates are required for each phase of the project.

☒ Proposed Emissions Limits and Modeled Ambient Concentration for All Regulated Air Pollutants. All proposed emission limits and modeled ambient concentrations for all regulated air pollutants must demonstrate compliance with all applicable air quality rules and regulations. Regulated air pollutants include criteria air pollutants (PM_{10}, SO_x, NO_2, O_3, CO, lead), toxic air pollutants listed pursuant to IDAPA 58.01.01.585 and 586, and hazardous air pollutants listed pursuant to Section 112 of the 1990 Clean Air Act Amendments (go to http://www.epa.gov/ttn/atw/188polls.html). Describe in detail how the proposed emissions limits and modeled ambient concentrations demonstrate compliance with each applicable air quality rule and regulation. It is requested that emissions calculations, assumptions, and documentation be submitted with sufficient detail so DEQ can verify the validity of the emissions estimates. Refer to IDAPA 58.01.01.213.01.c.

☒ Restrictions on a Source's Potential to Emit. Any proposed restriction on a source's potential to emit such that permitted emissions will be either below major source levels or below a significant increase must be described in detail in the pre-permit construction approval application. Refer to IDAPA 58.01.01.213.01.d.

☒ List all Applicable Air Quality Rules and Regulations. All applicable rules and regulations must be cited by the rule or regulation section/subpart that applies for each emissions unit. Refer to IDAPA 58.01.01.213.01.c.

☒ Certification of Pre-Permit Construction Approval Application. The pre-permit construction approval application must be signed by the Responsible Official and must contain a certification signed by the Responsible Official. The certification must state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. Refer to IDAPA 58.01.01.213.01.d and IDAPA 58.01.01.123.

☒ Submit the Pre-Construction Approval Application. Submit the pre-permit construction approval application and application fee to the following address:

Department of Environmental Quality
Air Quality Division
Stationary Source Program
1410 North Hilton
Boise, ID 83706-1255

Department of Environmental Quality - Air Quality Division
Toxic Air Pollutant (TAP) Preconstruction Compliance Application Completeness Checklist

This checklist is designed to aid the applicant in submitting a complete preconstruction compliance demonstration for toxic air pollutants (TAPs) in permit to construct applications. The applicant must place a check mark in the box for each section below that applies.

I. Actions Needed Before Submitting Application

☒ Refer to the Rule. Read the Demonstration of Preconstruction Compliance with Toxic Standards contained in IDAPA 58.01.01.210 (Rules Section 210) Rules for the Control of Air Pollution in Idaho (Rules). Toxic air pollutants (TAPs) are regulated in accordance with Rules Section 210 only from emission units constructed or modified on or after July 1, 1995.

Determine if a new (constructed after June 30, 1995) emission unit has the potential to emit a TAP listed in IDAPA 58.01.01.585 (Rules Section 585) or IDAPA 58.0101.586 (Rules Section 586). Potential toxic air pollutants can be determined by reviewing commonly available emission factors, such as EPA's AP-42, or calculating emissions using a mass balance. For TAPs that are emitted but not listed in Rules Section 585 and 586, contact the Air Permit Hotline at 877-5PERMIT.

Determine if the proposed construction or modification is exempt from the need to obtain a permit to construct in accordance with IDAPA 58.01.01.220-223. Use the Exemption Criteria and Reporting Requirements for TAPs IDAPA 58.01.01.223 checklist to assist you in the exemption determination. If the source does not qualify for an exemption in accordance with IDAPA 58.01.01.220-223 complete the following checklist and submit it with the permit application. Please note that fugitive TAP emissions are not included in the IDAPA 58.01.01.223 exemption determination, but fugitive TAP emissions are included in the analysis if a permit is required. Stated another way: if a source is required to obtain a Permit to Construct because it does not meet the exemption criteria for any reason all TAP emissions, including fugitive TAPs, are included in the compliance demonstration in the application for the permit to construct. Should you have any questions regarding the fact that all TAPs, including fugitive TAPs, are included in the TAP preconstruction compliance demonstration submitted with a permit to construct application you may call the Air Permit Hotline at 877-5PERMIT.

Will the new or modified source result in new or increased potential emissions of TAPs?

☒ Yes. If yes, continue to section II.

☐ No. If no, no further action is required.

II. Application Content

If a new source has the potential to emit a TAP, or if a modification to an existing source increases the potential to emit of a TAP, then one of the following methods (A-J) of demonstrating TAP preconstruction compliance must be documented for each TAP. Standard methods are one of A-C. The applicant may also use one of the specialized methods in D-J. Fugitive TAP emissions shall be included in the analysis. The compliance methods are based on the requirements of Rules Section 210. Applicants are often able to demonstrate preconstruction TAP compliance using a combination of methods A and B.

Emission Calculations

Emissions calculation methodologies used are dependent on whether a specific TAP is a non-carcinogen or a carcinogen and whether the compliance method chosen from the list below calls for controlled or uncontrolled emissions. Non-carcinogens are regulated based on a 24-hour averaging period and emission rates used for comparison to the non-carcinogen screening emissions level (EL) should be the maximum controlled or uncontrolled emissions quantity during any 24-hour period divided by 24. Carcinogens are regulated as a long term increment and emission rates used for comparison to the carcinogen EL should be the maximum controlled or uncontrolled emissions quantity during any 1 year period divided by 8760.

Modeling Analyses

Atmospheric dispersion modeling is required when controlled TAP emissions rates exceed ELs. Modeling analyses should be conducted in accordance with IDAPA 58.01.01.210.03. Quantification of Ambient Concentrations and the State of Idaho Air Quality Modeling Guideline (http;//www.deq.idaho.gov/air/data_reports/publications.cfm#model). For non-carcinogen 24-hour increments, compliance is demonstrated using the maximum modeled 24-hour-averaged concentration from available meteorological data (typically a five-year data set). For carcinogen long-term increments, compliance is demonstrated using the maximum modeled average concentration for the duration of the data set (one-year to five-year data set).

A submitted modeling report should clearly specify modeled emissions rates and results. All electronic model input files should be submitted, including BPIP input files.

Poly aromatic Hydrocarbons

Questions often arise regarding polyaromatic hydrocarbons as they are listed in Rules Section 586 of the Rules. The following two points are provided for clarification.

1) The following group of 7 PAH's (i.e. named POM), shall be combined and considered as one TAP equivalent in potency to benzo(a)pryrene:

    Benzo(a)anthracene, benzo(b)fluoranthene, benzo(k)fluoranthene, dibenzo(a, h) anthrancene, chrysene, indeno(1,2,3,-cd) pyrene, benzo (a) pyrene

2) All other PAH's are considered as a single pollutant and the emission of each is compared the PAH increment listed in Rules Section 586.

Compliance Methods

Fill in letter(s) (A-J) from the list below for TAP compliance demonstration method(s) used: A, B & C.

A. TAPs Compliance Using Uncontrolled Emissions (Rules Section 210.05)

☐ Calculate the uncontrolled emissions (Rules Section 210.05) of each TAP from new emissions units. Uncontrolled emission rates are emissions at maximum capacity without the effect of physical or operational limitations. See Quantification of Emission Rates (Rules Section 210.02). Show calculations and state all assumptions.

☐ Calculate the increase of TAP emissions from modified emissions units. Show calculations and state all assumptions. The increase in emissions for a modified emission unit is determined by subtracting the potential to emit the TAP before the modification from the uncontrolled potential to emit after the modification. In conducting this analysis please note the following for TAP emission rate increase determinations:

Uncontrolled emission rates after the modification are emissions at maximum capacity without the effect of physical or operational limitations.

When determining the emissions increase from existing permitted emissions units the emission rate before the modification is equivalent to the emission limits contained in the permit for the

TAPs or, if there no emission limits in the permit, by determining what the emission rate is under the physical or operational limitations contained in the permit.

☐ Aggregate the uncontrolled emissions for each TAP from all new emissions units with the increase in emissions from all modified emissions units.

☐ If the aggregated emissions increase for each TAP from the new and modified units, as determined above, are less than or equal to the respective TAP screening emissions level (EL) then preconstruction compliance with toxic standards has been demonstrated and no further analysis is required. Submit a table comparing the uncontrolled emissions rate to the applicable EL.

If aggregated emissions are greater than the respective screening emissions level (EL) for any pollutants, use another compliance demonstration method for those pollutants, such as methods B, C, or D.

B. TAP Compliance Using Uncontrolled Ambient Concentration (Rules Section 210.06)

☐ Determine the uncontrolled emissions of each TAP from new emission units and the increase in emissions from all modified emissions units as described above in compliance Method A. Show calculations and state all assumptions.

☐ Model the uncontrolled emissions of each TAP from new emissions units and the increase in emissions from all modified emissions units.

☐ If the uncontrolled ambient concentration is less than or equal to the acceptable ambient concentration increment listed in Rules Section 585 and 586 no further procedures for demonstrating preconstruction compliance will be required for that TAP as part of the application process. Submit a table comparing uncontrolled ambient concentrations to the applicable acceptable ambient concentration.

C. TAP Compliance Using Controlled Ambient Concentrations (Rules Section 210.08)

☒ Determine the controlled emissions from new emissions units and the controlled emission increase from modified emissions units. Show all calculations and state all assumptions, including the control methods.

☒ Model the controlled emissions of each TAP from new emissions units and the increase in controlled emissions from all modified emissions units.

TAP emissions levels (EL) included in Rules Section 585 and 586 are derived based on generic modeling. If the sum the of emissions from new and modified sources is below the EL compliance is demonstrated without the need to conduct site-specific dispersion modeling.

☒ If the controlled ambient concentration from emission increases from new emissions units and modified emissions units is less than the applicable acceptable ambient concentration no further procedures for demonstrating preconstruction compliance are required.

☒ The Department shall include an emission limit for the TAP in the permit to construct that is equal to or, if requested by the applicant, less than the emission rate that was used in the modeling (Rules Section 210.08.c).

In some instances the Department may consider a throughput limit or other inherently-limiting operational restriction in a permit as an effective emission limit for the TAP, rather than including a specific emission rate limit.. Note that the applicant may model uncontrolled emissions as described in compliance Method B in an attempt to avoid TAPs emissions limitations.

D. TAPs Compliance for NSPS and NESHAP Sources (Rules Section 210.20)

☐ If the owner or operator demonstrates that the TAP emissions from the source or modification is regulated by 40 CFR Part 60, 40 CFR Part 61 or 40 CFR Part 63, no further procedures for demonstrating preconstruction compliance will be required for that TAP.

☐ Provide a demonstration that the TAP is regulated under 40 CFR Part 60, 40 CFR Part 61 or 40 CFR Part 63. This demonstration must be specific for each TAP emitted.

E. TAP Compliance Using Net Emissions (Rules Section 210.09)

An applicant may use TAP net emissions to show preconstruction compliance; however this analysis may require more work than some of the others procedures available to demonstrate preconstruction compliance. When netting, all emissions increases and decreases of the TAP that have occurred within five years must be included in the analysis as described below.

☐ Determine the net emission increase for a TAP. A net emissions increase shall be an emission increase from a particular modification plus any other increase and decreases in actual emissions at the facility that are creditable and contemporaneous with particular modification (Rules Section 210.09). Show all calculations and state all assumptions.

☐ A creditable increase or decrease in actual emissions is contemporaneous with a particular modification if it occurs within five (5) years of the commencement of the construction or modification (Rules Section 210.09.a).

Actual emissions are (Rules Section 006.03):

- ☐ In general, actual emissions as of a particular date shall equal the average rate, in tons per year, at which the unit actually emitted the pollutant during a two year period which precedes the particular date and which is representative of normal source operation. The Department shall allow the use of a different time period upon a determination that it is more representative of normal source operation. Actual emissions shall be calculated using the unit’s actual operating hours, productions rates, and types of materials processed, stored, or combusted during the selected time period.

- ☐ The Department may presume that the source-specific allowable emissions for the unit are equivalent to actual emissions of the unit.

- ☐ For any emission unit (except electric utility steam generating units) that has not begun normal operations on the particular date, actual emissions shall equal the potential to emit of the unit on that date.

☐ Do not include emissions increases from emission units that have an uncontrolled emission rate that is 10% or less than the applicable screening emission level (EL) in Rules Section 585 and 586 (Rules Section 007.09.c.ii) and do not include emission increases from environmental remediation sources (Rules Section 007.09.c.iii). Show all calculations and state all assumptions.

☐ If the net emission increase is less than or equal to the applicable screening emissions level (EL) listed in Rules Section 585 and 586, no further procedures for demonstrating preconstruction compliance will be required (Rules Section 210.09.c).

☐ The Department shall include emission limits and other permit terms for the TAP in the permit to construct that will assure that the facility will be operated in the manner described in the preconstruction compliance demonstration (Rules Section 210.09.d).

In some instances the Department may consider a throughput limit or other inherently-limiting operational restriction in a permit as an effective emission limit for the TAP. rather than including a specific emission rate limit..

F. TAP Compliance Using Net Ambient Concentration (Rules Section 210.10)

☐ Determine the emission increase from the new source or modification, and all other creditable emission increases and decrease using the methods described above in compliance Method E.

☐ Model the emissions increases and decreases for each TAP. Modeling TAP decreases is accomplished by using negative valued emissions rates in the model input.

☐ If the net ambient concentration is less than or equal to the applicable ambient concentration increment listed in Rules Section 585 and 586, no further procedures for demonstrating preconstruction compliance are required.

☐ The Department shall include emission limits and other permit terms for the TAP in the permit to construct that will assure that the facility will be operated in the manner described in the preconstruction compliance demonstration (Rules Section 210.10.d).

In some instances the Department may consider a throughput limit or other inherently-limiting operational restriction in a permit as an effective emission limit for the TAP, rather than including a specific emission rate limit..

G. TAP Compliance Using T-RACT Ambient Concentration for Carcinogens (Rules Section 210.12)

The applicant may use T-RACT to demonstrate preconstruction compliance for TAPs listed in Rules Section 586 only.

T-RACT is an emissions standard based on the lowest emission of TAPs that a particular source is capable of meeting by application of control technology that is reasonably available, as determined by the Department, considering technological and economic feasibility. If control technology is not feasible, the emission standard may be based on the application of a design, equipment, work practice or operational requirement, or combination thereof (Rules Section 007.16).

T-RACT Submittal Requirements

☐ The applicant shall submit the following information to the Department identifying and documenting which control technologies or other requirements the applicant believes to be T-RACT (Rules Section 210.14).

The technical feasibility of a control technology or other requirements for a particular source shall be determined considering several factors including but not limited to:

- ☐ Process and operating procedures, raw materials and physical plant layout.
- ☐ The environmental impacts caused by the control technology that can not be mitigated, including but not limited to, water pollution and the production of solid wastes.
- ☐ The energy requirements of the control technology.

The economic feasibility of a control technology or other requirement, including the costs of necessary mitigation measures, for a particular source shall be determined considering several factors including, but not limited to:

- ☐ Capital costs.
- ☐ Cost effectiveness, which is the annualized cost of the control technology divided by the amount of emission reduction.
- ☐ The difference in costs between the particular source and other similar sources, if any, that have implemented emissions reductions.

☐ Compare the source's or modification's approved T-RACT ambient concentration to the applicable acceptable ambient concentration increment listed in Rules Section 586 multiplied by a factor of 10. If the sources approved T-RACT concentration is less than or equal to 10 times the applicable acceptable ambient concentration increment listed in Rules Section 586, no further procedures for demonstrating preconstruction compliance will be required.

☐ If an application is submitted to the Department without T-RACT and determined complete, and T-RACT is later determined to be applicable the completeness determination of the application will be revoked until a supplemental application is submitted and determined complete. When the supplemental application is determined complete, the timeline for agency action shall be reinitiated (Rules Section 210.13.b).

☐ If the Department determines that the source has proposed T-RACT, the Department shall develop emission standards to be incorporated into a permit to construct.

In some instances, the Department may consider a throughput limit or other inherently limiting operational restriction in a permit as an effective emission limit for the TAP, rather than including a specific emission rate limit..

H. TAP Compliance Using the Short Term Source Factor (Rules Section 210.15)

☐ For short term sources, the applicant may utilize a short term adjustment factor of ten (10) only for a carcinogenic pollutant listed in Rules Section 586. For a carcinogen listed in Rules Section 586 multiply either the applicable acceptable ambient concentration increment or the screening emission rate (EL), but not both, by ten (10) to demonstrate preconstruction compliance (Rules Section 210.15).

☐ A short term source is any new stationary source or modification to an existing source, with an operational life no greater than five (5) years from the inception of any operations to cessation of actual operations (Rules Section 210.15).

I. TAP Compliance for Environmental Remediation Sources (Rules Section 210.16)

☐ For remediation sources subject to or regulated by the Resource Conservation and Recovery Act and the Idaho Rules and Standard for Hazardous Waste, or the comprehensive Environmental Response, Compensation and Liability Act or a consent order, if the estimated ambient concentration is greater than the acceptable ambient impact increment listed in Rules Section 585 and 586, Best Available Control Technology shall be applied and operated until the estimated uncontrolled emission from the remediation source are below the applicable acceptable ambient concentration increment (Rules Section 210.16).

J. TAP Compliance Using Offset Ambient Concentration (Rules Section 210.11)

☐ Contact the Department prior to proposing to utilize Offset Ambient Concentrations to demonstrate preconstruction compliance.

☐ Emission offsets must satisfy the requirements for emission reduction credits (Rules Section 460).

- The proposed level of allowable emissions must be less than the actual emissions of the emissions units providing the offsets (Rules Section 460.01).
- An air quality permit must be issued that restricts the potential to emit of the emission unit providing the offset.
- Emission reduction imposed by local, state or federal regulations or permits shall not be allowed.

☐ Compare the source's or modifications approved emission offset ambient concentration to the applicable acceptable ambient concentration listed in Rules Section 585 and 586. If the source's or modifications approved offset concentration is less than the acceptable ambient concentration listed in Rules Section 585 and 586, no further procedures for demonstrating preconstruction compliance will be required.

☐ The Department shall include emission limits and other permit terms for the TAP in the permit to construct that will assure that the facility will be operated in the manner described in the preconstruction compliance demonstration (Rules Section 210.10.d).

Department of Environmental Quality

Dispersion Modeling Protocol Checklist

The following should be discussed in a dispersion modeling protocol:

1) ✓General project description.
2) ✓Describe the general modeling approach used. If the analyses include multiple operational scenarios, these should be thoroughly described.
3) Thoroughly describe the area where the project will be located, including the attainment status for all criteria pollutants.
4) ✓Modeling applicability. Discuss how it will be determined what emissions sources and pollutants to include in the modeling analyses.
5) ✓Describe the model proposed for the analyses, including the version number.
6) ✓List the meteorological data proposed for the project and describe how those data are representative for the application site.
7) ✓List the source of terrain data used in the modeling analyses. If terrain affects are not proposed for the analyses, a justification for this should be provided.
8) ✓Provide a facility plot plan with emissions sources and buildings clearly identified, if available.
9) ✓Describe the modeling domain and the receptor network used. Suggested receptor spacing provided in the Idaho Air Modeling Guideline are general suggestions. DEQ may require a different grid spacing to adequately resolve maximum modeled concentrations.
10) ✓Provide justification for the ambient air boundary. The facility must prevent public access inside the ambient air boundary using methods described in the Idaho Air Modeling Guideline.
11) ✓If known, emissions rates used in the modeling should be listed. This will give DEQ reviews an idea of the magnitude of the project. Describe how modeling emissions rates will be calculated for various averaging periods (exa. 1-hour, 24-hour, and annual for sources that do not operate continuously).
12) ✓If known, emissions release parameters associated with emissions release points should be listed. Documentation and justification of these values should also be provided.
13) ✓Describe what values will be used for background concentrations if a full impact analysis is required. DEQ may be consulted for assistance with determining background concentrations.
14) ✓Describe what modeled values will be used to evaluate compliance with standards (highest, 1st high values; highest, 2nd high values; etc.)

1.2 Application Cover Sheet (Form CSPTC)

This section contains the application cover sheet form.

DEQ AIR QUALITY PROGRAM
1410 N. Hilton, Boise, ID 83706
For assistance, call the
Air Permit Hotline – 1-877-5PERMIT

Cover Sheet for Air Permit Application – Permit to Construct **Form CSPTC**

Please see instructions on page 2 before filling out the form.

COMPANY NAME, FACILITY NAME, AND FACILITY ID NUMBER			
1. Company Name	Great Western Malting Company		
2. Facility Name	Great Western Malting Pocatello Plant	3. Facility ID No.	005-00035
4. Brief Project Description - One sentence or less	Expanding the malting capability of the plant		

PERMIT APPLICATION TYPE

5. ☐ New Source ☐ New Source at Existing Facility ☐ PTC for a Tier I Source Processed Pursuant to IDAPA 58.01.01.209.05.c
☐ Unpermitted Existing Source ☐ Facility Emissions Cap ☒ Modify Existing Source: Permit No.: P-060312 Date Issued: 10/4/2006
☐ Required by Enforcement Action: Case No.:_____

6. ☒ Minor PTC ☐ Major PTC

FORMS INCLUDED

Included	N/A	Forms		DEQ Verify
☒	☐	Form CSPTC – Cover Sheet (Section 1)		☐
☒	☐	Form GI – Facility Information (Section 1)		☐
☒	☐	Form EU0 – Emissions Units General	Please specify number of EU0s attached: 17	☐
☒	☐	Form EU1– Industrial Engine Information	Please specify number of EU1s attached: 1	☐
☐	☒	Form EU2– Nonmetallic Mineral Processing Plants	Please specify number of EU2s attached: _____	☐
☐	☒	Form EU3– Spray Paint Booth Information	Please specify number of EU3s attached: _____	☐
☐	☒	Form EU4– Cooling Tower Information	Please specify number of EU3s attached: _____	☐
☒	☐	Form EU5 – Boiler Information	Please specify number of EU4s attached: 6	☐
☐	☒	Form CBP– Concrete Batch Plant	Please specify number of CBPs attached: _____	☐
☐	☒	Form HMAP – Hot Mix Asphalt Plant	Please specify number of HMAPs attached: _____	☐
☐	☒	PERF – Portable Equipment Relocation Form		☐
☐	☒	Form AO – Afterburner/Oxidizer		☐
☐	☒	Form CA – Carbon Adsorber		☐
☒	☐	Form CYS – Cyclone Separator	Please specify number of CYS attached: 1	☐
☐	☒	Form ESP – Electrostatic Precipitator		☐
☒	☐	Form BCE– Baghouses Control Equipment	Please specify number of BCEs attached: 10	☐
☐	☒	Form SCE– Scrubbers Control Equipment		☐
☐	☒	Form VSCE – Venturi Scrubber Control Equipment		☐
☐	☒	Form CAM – Compliance Assurance Monitoring		☐
☒	☐	Forms EI-– Emissions Inventory (Tables 5-1 through 5-22 and Appendix E)		☐
☒	☐	PP – Plot Plan (Figure 3-1)		☐
☒	☐	Forms MI1 – MI4 – Modeling	(Excel workbook, all 4 worksheets)	☐
☒	☐	Form FRA – Federal Regulation Applicability (Section 4.2)		☐

1.3 General Information (Form GI)

This section contains the general information form.

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1410 N. Hilton, Boise, ID 83706
For assistance, call the
Air Permit Hotline: 1-877-5PERMIT

General Information **Form GI**
Revision 7
6/29/12

Please see instructions on back page before filling out the form. All information is required. If information is missing, the application will not be processed.

Identification

1. Facility name: Great Western Malting Company

2. Existing facility identification number: 005-00035

☐ **Check if new facility (not yet operating)**

3. Brief project description: Expanding malting capability at the Pocatello plant

Facility Information

4. Primary facility permitting contact name: Jay Hamachek — **Contact type:** Responsible official

Telephone number: 360 699 6785 — **E-mail:** jay.hamachek@greatwesternmalting.com

5. Alternate facility permitting contact name: Tevis Vance — **Alternate contact type:** Facility permitting contact

Telephone number: 208 239 5475 — **E-mail:** tevis.vance@greatwesternmalting.com

6. Mailing address where permit will be sent (street/city/county/state/zip code): 1666 Kraft Road, Pocatello, Bannock, Idaho, 83204

7. Physical address of permitted facility (if different than mailing address) (street/city/county/state/zip code):

8. Is the equipment portable? ☐ Yes* ☒ No — ***If yes, complete and attach PERF; see instructions.**

9. NAICS codes: Primary NAICS: 311213 — **Secondary NAICS:**

10. Brief business description and principal product produced: Production of barley malt and wheat malt and feed

11. Identify any adjacent or contiguous facility this company owns and/or operates: None

12. Specify type of application ☒ **Permit to construct (PTC); application fee of $1,000 required. See instructions.**

☐ **Tier I permit** ☐ **Tier II permit** ☐ **Tier II/Permit to construct**

For Tier I permitted facilities only: If you are applying for a PTC then you must also specify how the PTC will be incorporated into the Tier I permit.

☐ **Co-process Tier I modification and PTC** ☐ **Incorporate PTC at the time of Tier I renewal** ☐ **Administratively amend the Tier I permit to incorporate the PTC upon applicant's request (IDAPA 58.01.01.209.05.a, b, or c)**

Certification

In accordance with IDAPA 58.01.01.123 (Rules for the Control of Air Pollution in Idaho), I certify based on information and belief formed after reasonable inquiry, the statements and information in the document(s) are true, accurate, and complete.

13. Responsible official's name: Jay Hamachek — **Official's title:** Director

Official's address: 700 Washington Street, Suite 508, Vancouver WA 98660

Telephone number: 360-699-6785 — **E-mail:** jay.hamachek@greatwesternmalting.c

Official's signature: [signature] — **Date:** 12/3/15

☒ **14. Check here to indicate that you want to review the draft permit before final issuance.**

1.4 Equipment Forms

The malt expansion project will have new equipment and new air emission sources constructed at the Pocatello plant. A list of the new air emission sources is presented in Table 1-1. The table includes the name of the source, the source identification number, the capacity or throughput of the equipment, whether the source will have add-on air pollution control, the identification number of the air pollution control device, the number of the stack (emission point) and the pollutants emitted.

Table 1-1: List of New or Modified Air Emission Sources

Source Name	Source ID	Capacity or Throughput	Air Pollution Control Device (APCD)	APCD ID	Emission Point Stack ID	Pollutants
Steep Tank Fill Conveyor 1	STC1	160 MT/hr	Filter, DT CPV1	STC1F	S1	PM10, PM2.5
Steep Tank Fill Conveyor 2	STC2	160 MT/hr	Filter, DT CPV1	STC2F	S2	PM10, PM2.5
Steep Tanks 1-8-Upper	STA1-STA8	50 MT each	None	--	S3-S10	CO2
Steep Tanks 1-8-Lower	STB1-STB2	50 MT each	None	--	S11-S18	CO2
Germination Vessel 1	GV1	400 MT	None	--	S19 & S20	Cl2
Germination Vessel 2	GV2	400 MT	None	--	S21 & S22	Cl2
Germination Vessel 3	GV3	400 MT	None	--	S23 & S24	Cl2
Germination Vessel 4	GV4	400 MT	None	--	S25 & S26	Cl2
Kiln 2	K2	21 MT/hr	None	--	S31	PM10, PM2.5, VOC
Kiln New Malt Leg Conveyor	NML	219 MT/hr	Filter, DT CPV3	NMLF	S32	PM10, PM2.5
Malt Analysis Bin 1- fill	BA1	375 MT each	Filter, DT CPV1	BA1F	S33	PM10, PM2.5
Malt Analysis Bin 2- fill	BA2	375 MT each	Filter, DT CPV1	BA2F	S34	PM10, PM2.5
Kiln Byproduct Cyclone	KBPC	5 MT/hr	Filter, DT CPV1	KBPCF	S35	PM10, PM2.5
New Malt Conveyor 3	NMC3	160 MT/hr	Filter, DT CPV1	NMC3F	S36	PM10, PM2.5
Micro Bins 1-4-fill conveyor	MBC	46 MT each	Filter, DT CPV1	MBCF	S37	PM10, PM2.5
Malt Storage Bins 1-5-fill conveyor 1	NMSBC1	750 MT each	Filter, DT CPV1	NMSBC1F	S46	PM10, PM2.5

Source Name	Source ID	Capacity or Throughput	Air Pollution Control Device (APCD)	APCD ID	Emission Point Stack ID	Pollutants
Malt Storage Bins 6-10-fill conveyor 2	NMSBC2	750 MT each	Filter, DT CPV1	NMSBC2F	S47	PM10, PM2.5
Malt Cleaning drum scalper & aspirator	MC (modification)	150 MT/hr	Existing baghouses	Baghouses 2 & 3	BH2 & BH3	PM10, PM2.5
Kiln 2 Air Heater Burner 1	KB1	18.15 MM Btu/hr	Burner design	--	S27	PM10, PM2.5, CO, NOx, SO2, VOC, TAPs, CO2
Kiln 2 Air Heater Burner 2	KB2	18.15 MM Btu/hr	Burner design	--	S28	PM10, PM2.5, CO, NOx, SO2, VOC, TAPs, CO2
Kiln 2 Air Heater Burner 3	KB3	18.15 MM Btu/hr	Burner design	--	S29	PM10, PM2.5, CO, NOx, SO2, VOC, TAPs, CO2
Kiln 2 Air Heater Burner 4	KB4	18.15 MM Btu/hr	Burner design	--	S30	PM10, PM2.5, CO, NOx, SO2, VOC, TAPs, CO2
Germination Vessel Boiler 1	GVB1	2 MM Btu/hr	Burner design	--	S38	PM10, PM2.5, CO, NOx, SO2, VOC, TAPs, CO2
Germination Vessel Boiler 2	GVB2	2 MM Btu/hr	Burner design	--	S39	PM10, PM2.5, CO, NOx, SO2, VOC, TAPs, CO2
Germination Vessel Boiler 3	GVB3	2 MM Btu/hr	Burner design	--	S40	PM10, PM2.5, CO, NOx, SO2, VOC, TAPs, CO2
Germination Vessel Boiler 4	GVB4	2 MM Btu/hr	Burner design	--	S41	PM10, PM2.5, CO, NOx, SO2, VOC, TAPs, CO2
Germination Vessel Boiler 5	GVB5	2 MM Btu/hr	Burner design	--	S42	PM10, PM2.5, CO, NOx, SO2, VOC, TAPs, CO2
Germination Vessel Boiler 6	GVB6	2 MM Btu/hr	Burner design	--	S43	PM10, PM2.5, CO, NOx, SO2, VOC, TAPs, CO2

Source Name	Source ID	Capacity or Throughput	Air Pollution Control Device (APCD)	APCD ID	Emission Point Stack ID	Pollutants
Steep building Air make-up heater 1	MAU1	2.188 MM Btu/hr	None	--	S44	PM10, PM2.5, CO, NOx, SO2, VOC, TAPs, CO2
Steep building Air make-up heater 2	MAU2	2.188 MM Btu/hr	None	--	S45	PM10, PM2.5, CO, NOx, SO2, VOC, TAPs, CO2
Emergency Generator (existing)	EG1	45 kW	None	--	EG	PM10, PM2.5, CO, NOx, SO2, VOC, TAPs, CO2
Kiln 1 Air Heater Burner 1	K1	7.9 MM Btu/hr	Burner design	--	KS1	PM10, PM2.5, CO, NOx, SO2, VOC, TAPs, CO2
Kiln 1 Air Heater Burners 2-5	K2-K5	31.6 MM Btu/hr (7.9 MM Btu/hr each burner)	Burner design	--	KS2	PM10, PM2.5, CO, NOx, SO2, VOC, TAPs, CO2
Kiln 1 Air Heater Burner 6	K6	7.9 MM Btu/hr	Burner design	--	KS3	PM10, PM2.5, CO, NOx, SO2, VOC, TAPs, CO2
Kiln 1 Air Heater Burners 7-9	K7-K9	23.7 MM Btu/hr (7.9 MM Btu/hr each burner)	Burner design	--	KS4	PM10, PM2.5, CO, NOx, SO2, VOC, TAPs, CO2
Kiln 1 Air Heater Burner 10	K10	7.9 MM Btu/hr	Burner design	--	KS5	PM10, PM2.5, CO, NOx, SO2, VOC, TAPs, CO2

The Idaho DEQ equipment forms that correspond to each new emission source are presented in the following sections:

1.4.1 General Emission Unit Forms

1.4.2 Boiler Forms

1.4.3 Cyclone Form

1.4.4 Engine Form

1.4.5 Dust Filter Forms

1.4.1 General Emission Unit Forms (EU0)

The forms included in this section are for the following emission sources:

Source Name	Source ID	Source Name	Source ID
Steep Tank Fill Conveyor 1	STC1	New Malt Conveyor 3	NMC3
Steep Tank Fill Conveyor 2	STC2	Micro Bins 1-4- fill conveyor	MBC
Steep Tanks 1-8-Upper	STA1-STA8	Malt Storage Bins 1-5-fill conveyor 1	NMSBC1
Steep Tanks 1-8-Lower	STB1-STB8	Malt Storage Bins 6-10-fill conveyor 2	NMSBC2
Germination Vessels 1-4	GV1- GV4	Kiln 2 Air Heater Burners 1-4	KB1-KB4
Kiln 2	K2	Steep Bldg. Make-up Air Heaters 1 & 2	MAU1 & 2
Kiln New Malt Leg Conveyor	NML		
Malt Analysis Bin 1- fill	BA1	Kiln 1 Air Heater Burners 1-10	KS1-KS5
Malt Analysis Bin 2- fill	BA2	Malt Cleaning drum scalper & aspirator*	MC

* Malt Cleaning (MC) is an existing activity that is part of the Barley Unloading, Barley and Malt Handling and Loadout emission sources identified in the air permit. Existing Baghouse 2 (BH2) is used to control about 67% of Malt Cleaning dust emissions with about 33% going to existing Baghouse 3 (BH3). The Malt Cleaning activity will be modified in the expansion project by replacing some of the malt cleaning equipment with a new drum scalper and new aspirator. The dust emissions will continue to be controlled using BH2 and BH3.

Manufacturer's information for the new Kiln 2 heater burners (KB1-KB4) and new Kiln 1 heater burners is provided in Appendix A.

Manufacturer's information for the make-up air heaters (MAU1 & MAU2) is provided in Appendix B.

Information on the replacement malt cleaning scalper and aspirator is provided in Appendix F.

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Emissions Unit - General **Form EU0**
Revision 4
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Great Western Malting Company	Great Western Malting Pocatello Plant	005-00035
4. Brief Project Description:	Expanding malting capability at the Pocatello plant	

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	STEEP TANKS CONVEYOR 1 (fill)
6.	EU ID Number:	STC1
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	CUSTOM
9.	Model:	N/A
10..	Maximum Capacity:	160 MT/hour
11.	Date of Construction:	2016
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Steep Tank Conveyor 1 Filter (STC1F)		
15. Date of Installation:	2016	16. Date of Modification (if any):	
17. Manufacturer and Model Number:	Donaldson Torit CPV1		
18. ID(s) of Emission Unit Controlled:	STC1		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	99.5	99.5				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency. see control device form STC1F)

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	24 HR/DAY, 8760 HR/YR
23.	Maximum Operation:	24 HR/DAY, 8760 HR/YR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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Emissions Unit - General **Form EU0**
Revision 4
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION		
1. Company Name:	2. Facility Name:	3. Facility ID No:
Great Western Malting Company	Great Western Malting Pocatello Plant	005-00035
4. Brief Project Description:	Expanding malting capability at the Pocatello plant	

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION		
5.	Emissions Unit (EU) Name:	STEEP TANKS CONVEYOR 2 (FILL)
6.	EU ID Number:	STC2
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	CUSTOM
9.	Model:	N/A
10..	Maximum Capacity:	160 MT/hour
11.	Date of Construction:	2016
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT			
14. Control Equipment Name and ID:	Steep Tank Conveyor 2 Filter (STC2F)		
15. Date of Installation:	2016	16. Date of Modification (if any):	
17. Manufacturer and Model Number:	Donaldson Torit CPV1		
18. ID(s) of Emission Unit Controlled:	STC2		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	99.5	99.5				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency. see control device form STC2F)

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)		
22.	Actual Operation:	24 HR/DAY, 8760 HR/YR
23.	Maximum Operation:	24 HR/DAY, 8760 HR/YR

REQUESTED LIMITS		
24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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Air Permit Hotline – 1-877-5PERMIT

Emissions Unit - General **Form EU0**
Revision 4
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Great Western Malting Company	Great Western Malting Pocatello Plant	005-00035
4. Brief Project Description:	Expanding malting capability at the Pocatello plant	

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	STEEP TANKS- 8 TANKS- UPPER LEVEL
6.	EU ID Number:	STA1- STA8
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	CUSTOM
9.	Model:	N/A
10..	Maximum Capacity:	50 MT EACH
11.	Date of Construction:	2016
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☒ No ☐ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:			
15. Date of Installation:		16. Date of Modification (if any):	
17. Manufacturer and Model Number:			
18. ID(s) of Emission Unit Controlled:			
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☐ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☐ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency						

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	24 HR/DAY, 8760 HR/YR
23.	Maximum Operation:	24 HR/DAY, 8760 HR/YR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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Emissions Unit - General **Form EU0**
Revision 4
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Great Western Malting Company	Great Western Malting Pocatello Plant	005-00035
4. Brief Project Description:	Expanding malting capability at the Pocatello plant	

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	STEEP TANKS- 8 TANKS- LOWER LEVEL
6.	EU ID Number:	STB1- STB8
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	CUSTOM
9.	Model:	N/A
10..	Maximum Capacity:	50 MT EACH
11.	Date of Construction:	2016
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☒ No ☐ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:			
15. Date of Installation:		16. Date of Modification (if any):	
17. Manufacturer and Model Number:			
18. ID(s) of Emission Unit Controlled:			
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☐ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☐ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency						

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	24 HR/DAY, 8760 HR/YR
23.	Maximum Operation:	24 HR/DAY, 8760 HR/YR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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Emissions Unit - General **Form EU0**
Revision 4
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Great Western Malting Company	Great Western Malting Pocatello Plant	005-00035
4. Brief Project Description:	Expanding malting capability at the Pocatello plant	

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	Germination Vessels- 4 vessels
6.	EU ID Number:	GV1- GV4
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	CUSTOM
9.	Model:	N/A
10..	Maximum Capacity:	400 MT EACH
11.	Date of Construction:	2016
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☒ No ☐ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:			
15. Date of Installation:		16. Date of Modification (if any):	
17. Manufacturer and Model Number:			
18. ID(s) of Emission Unit Controlled:			
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☐ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☐ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency						

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	24 HR/DAY, 8760 HR/YR
23.	Maximum Operation:	24 HR/DAY, 8760 HR/YR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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Emissions Unit - General **Form EU0**
Revision 4
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Great Western Malting Company	Great Western Malting Pocatello Plant	005-00035
4. Brief Project Description:	Expanding malting capability at the Pocatello plant	

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	MALT KILN 2
6.	EU ID Number:	KILN2
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	CUSTOM
9.	Model:	N/A
10..	Maximum Capacity:	400 MT
11.	Date of Construction:	2016
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☒ No ☐ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:			
15. Date of Installation:		16. Date of Modification (if any):	
17. Manufacturer and Model Number:			
18. ID(s) of Emission Unit Controlled:			
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☐ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☐ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency						

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	24 HR/DAY, 8760 HR/YR
23.	Maximum Operation:	24 HR/DAY, 8760 HR/YR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☒ Yes ☐ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☒ Production Limit(s):	21.1 MT/HR DAILY ROLLING AVERAGE; 162,000 MT/YR
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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Emissions Unit - General **Form EU0**
Revision 4
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Great Western Malting Company	Great Western Malting Pocatello Plant	005-00035
4. Brief Project Description:	Expanding malting capability at the Pocatello plant	

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	NEW MALT LEG CONVEYOR
6.	EU ID Number:	NML
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	CUSTOM
9.	Model:	N/A
10..	Maximum Capacity:	219 MT/HR
11.	Date of Construction:	2016
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	New malt leg conveyor filter, NMLF		
15. Date of Installation:	2016	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	Donaldson Torit, CPV3		
18. ID(s) of Emission Unit Controlled:	NML		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	99.5	99.5				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency. See baghouse form NMLF

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	24 HR/DAY, 8760 HR/YR
23.	Maximum Operation:	24 HR/DAY, 8760 HR/YR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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Emissions Unit - General **Form EU0**
Revision 4
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Great Western Malting Company	Great Western Malting Pocatello Plant	005-00035
4. Brief Project Description:	Expanding malting capability with 2 new analysis bins	

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	ANALYSIS BIN 1 FILL
6.	EU ID Number:	BA1
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	CUSTOM
9.	Model:	N/A
10..	Maximum Capacity:	375 MT
11.	Date of Construction:	2016
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Analysis Bin 1 fill filter, BA1F		
15. Date of Installation:	2016	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	Donaldson Torit, CPV1		
18. ID(s) of Emission Unit Controlled:	BA1		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	99.5	99.5				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency. See baghouse form BA1F

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	24 HR/DAY, 8760 HR/YR
23.	Maximum Operation:	24 HR/DAY, 8760 HR/YR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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Emissions Unit - General **Form EU0**
Revision 4
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION		
1. Company Name:	2. Facility Name:	3. Facility ID No:
Great Western Malting Company	Great Western Malting Pocatello Plant	005-00035
4. Brief Project Description:	Expanding malting capability with 2 new analysis bins	

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION		
5.	Emissions Unit (EU) Name:	ANALYSIS BIN 2 FILL
6.	EU ID Number:	BA2
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	CUSTOM
9.	Model:	N/A
10..	Maximum Capacity:	375 MT
11.	Date of Construction:	2016
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT			
14. Control Equipment Name and ID:	Analysis Bin 2 fill filter, BA2F		
15. Date of Installation:	2016	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	Donaldson Torit, CPV1		
18. ID(s) of Emission Unit Controlled:	BA2		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	99.5	99.5				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency. See baghouse form BA2F

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)		
22.	Actual Operation:	24 HR/DAY, 8760 HR/YR
23.	Maximum Operation:	24 HR/DAY, 8760 HR/YR

REQUESTED LIMITS		
24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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Emissions Unit - General **Form EU0**
Revision 4
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Great Western Malting Company	Great Western Malting Pocatello Plant	005-00035
4. Brief Project Description:	Expanding malting capability at the Pocatello plant	

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	NEW MALT CONVEYOR 3
6.	EU ID Number:	NMC3
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	CUSTOM
9.	Model:	N/A
10..	Maximum Capacity:	160 MT/HR
11.	Date of Construction:	2016
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	New malt conveyor 3 filter, NMC3F		
15. Date of Installation:	2016	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	Donaldson Torit, CPV1		
18. ID(s) of Emission Unit Controlled:	NMC3		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	99.5	99.5				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency. See baghouse form NMC3F

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	24 HR/DAY, 8760 HR/YR
23.	Maximum Operation:	24 HR/DAY, 8760 HR/YR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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Emissions Unit - General **Form EU0**
Revision 4
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Great Western Malting Company	Great Western Malting Pocatello Plant	005-00035
4. Brief Project Description:	Expanding malting capability with 4 new micro bins	

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	MICRO BINS 1-4 FILL CONVEYOR
6.	EU ID Number:	MBC
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	CUSTOM
9.	Model:	N/A
10..	Maximum Capacity:	46 MT Each Bin
11.	Date of Construction:	2016
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Micro Bins conveyor filter, MBCF		
15. Date of Installation:	2016	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	Donaldson Torit, CPV1		
18. ID(s) of Emission Unit Controlled:	MBC		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	99.5	99.5				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency. See baghouse form MBCF

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	24 HR/DAY, 8760 HR/YR
23.	Maximum Operation:	24 HR/DAY, 8760 HR/YR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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Emissions Unit - General **Form EU0**
Revision 4
08/28/08

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IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Great Western Malting Company	Great Western Malting Pocatello Plant	005-00035
4. Brief Project Description:	Expanding malting capability with 10 new malt storage bins	

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	NEW MALT STORAGE BINS 1-5 FILL CONVEYOR 1
6.	EU ID Number:	NMSBC1
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	CUSTOM
9.	Model:	N/A
10..	Maximum Capacity:	750 MT Each Bin
11.	Date of Construction:	2016
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	New Malt Storage Bin Conveyor 1 Filter, NMSBC1F		
15. Date of Installation:	2016	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	Donaldson Torit, CPV1		
18. ID(s) of Emission Unit Controlled:	NMSBC1		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	99.5	99.5				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency. See baghouse form NMSBC1F

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	24 HR/DAY, 8760 HR/YR
23.	Maximum Operation:	24 HR/DAY, 8760 HR/YR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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Emissions Unit - General **Form EU0**
Revision 4
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION		
1. Company Name:	2. Facility Name:	3. Facility ID No:
Great Western Malting Company	Great Western Malting Pocatello Plant	005-00035
4. Brief Project Description:	Expanding malting capability with 10 new malt storage bins	

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION		
5.	Emissions Unit (EU) Name:	NEW MALT STORAGE BINS 6-10 FILL CONVEYOR 2
6.	EU ID Number:	NMSBC2
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	CUSTOM
9.	Model:	N/A
10..	Maximum Capacity:	750 MT EACH BIN
11.	Date of Construction:	2016
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT						
14. Control Equipment Name and ID:	New Malt Storage Bin Conveyor 2 Filter, NMSBC1F					
15. Date of Installation:	2016	16. Date of Modification (if any):	N/A			
17. Manufacturer and Model Number:	Donaldson Torit, CPV1					
18. ID(s) of Emission Unit Controlled:	NMSBC2					
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No					
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)					
	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	99.5	99.5				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency. See baghouse form NMSBC2F

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)		
22.	Actual Operation:	24 HR/DAY, 8760 HR/YR
23.	Maximum Operation:	24 HR/DAY, 8760 HR/YR

REQUESTED LIMITS		
24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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Emissions Unit - General **Form EU0**
Revision 4
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Great Western Malting Company	Great Western Malting Pocatello Plant	005-00035
4. Brief Project Description:	Expanding malting capability at the Pocatello plant with 4 air-to-air heaters	

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	4 KILN BURNERS (1 BURNER PER AIR-TO-AIR HEATER)
6.	EU ID Number:	KB1- KB4
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	MAXON BURNERS (AIR FROEHLICH AIR HEATERS)
9.	Model:	KINEDIZER LE- 10"
10..	Maximum Capacity:	18.15 MM BTU/HR HEAT INPUT each (NATURAL GAS)
11.	Date of Construction:	2016
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☒ No ☐ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	burner design		
15. Date of Installation:		16. Date of Modification (if any):	
17. Manufacturer and Model Number:			
18. ID(s) of Emission Unit Controlled:			
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☐ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☐ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency						

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	24 HR/DAY, 8760 HR/YR
23.	Maximum Operation:	24 HR/DAY, 8760 HR/YR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☒ Yes ☐ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☒ Material Usage Limit(s):	420 MM CF NAT GAS/YEAR TOTAL ALL 4 BURNERS
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	PTE LIMIT

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Emissions Unit - General **Form EU0**
Revision 4
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Great Western Malting Company	Great Western Malting Pocatello Plant	005-00035
4. Brief Project Description:	Expanding malting capability with 2 make-up air heaters for steep tank building	

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	MAKE-UP AIR UNITS 1 AND 2
6.	EU ID Number:	MAU1 & MAU2
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	REZNOR
9.	Model:	PCDH-175
10..	Maximum Capacity:	2.1888 MM BTU/HR HEAT INPUT EACH (NATURAL GAS)
11.	Date of Construction:	2016
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☒ No ☐ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	
15. Date of Installation:	16. Date of Modification (if any):
17. Manufacturer and Model Number:	
18. ID(s) of Emission Unit Controlled:	
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☐ No
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☐ No (If Yes, attach and label manufacturer guarantee)

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency						

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	24 HR/DAY, 8760 HR/YR
23.	Maximum Operation:	24 HR/DAY, 8760 HR/YR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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Emissions Unit - General **Form EU0**
Revision 4
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION		
1. Company Name:	2. Facility Name:	3. Facility ID No:
Great Western Malting Company	Great Western Malting Pocatello Plant	005-00035
4. Brief Project Description:	Replacing air heaters in existing malthouse kiln	

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION		
5.	Emissions Unit (EU) Name:	10 AIR-TO-AIR HEATERS (1 BURNER PER HEATER)
6.	EU ID Number:	K1- K10 (STACKS: KS1-KS5)
7.	EU Type:	☐ New Source ☐ Unpermitted Existing Source ☒ Modification to a Permitted Source -- Previous Permit #:P-060312 Date Issued: Oct. 2006
8.	Manufacturer:	MAXON BURNERS (AIR FROEHLICH AIR HEATERS)
9.	Model:	KINEDIZER LE- 6"
10..	Maximum Capacity:	7.9 MM BTU/HR HEAT INPUT EACH (NATURAL GAS)
11.	Date of Construction:	2017
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☒ No ☐ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT						
14. Control Equipment Name and ID:	burner design					
15. Date of Installation:		16. Date of Modification (if any):				
17. Manufacturer and Model Number:						
18. ID(s) of Emission Unit Controlled:						
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☐ No					
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☐ No (If Yes, attach and label manufacturer guarantee)					
	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency						
21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.						

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)		
22.	Actual Operation:	24 HR/DAY, 8760 HR/YR
23.	Maximum Operation:	24 HR/DAY, 8760 HR/YR

REQUESTED LIMITS		
24.	Are you requesting any permit limits?	☒ Yes ☐ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☒ Material Usage Limit(s):	290 MM CF NAT GAS/YEAR TOTAL ALL 10 BURNERS
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	PTE LIMIT

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Emissions Unit - General **Form EU0**
Revision 4
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Great Western Malting Company	Great Western Malting Pocatello Plant	005-00035
4. Brief Project Description:	Expanding malting capability at the Pocatello plant	

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	MALT CLEANING- DRUM SCALPER & ASPIRATOR
6.	EU ID Number:	MC
7.	EU Type:	☐ New Source ☐ Unpermitted Existing Source ☒ Modification to a Permitted Source -- Previous Permit #:060312 Date Issued: 10/4/2006
8.	Manufacturer:	CIMBRIA drum scalper and KICE aspirator
9.	Model:	N/A
10..	Maximum Capacity:	150 MT/HR
11.	Date of Construction:	2016
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Baghouse 2 (BH2) & Baghouse 3 (BH3)		
15. Date of Installation:	1980	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	existing		
18. ID(s) of Emission Unit Controlled:	MC (malt cleaning)		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency						

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	24 HR/DAY, 8760 HR/YR
23.	Maximum Operation:	24 HR/DAY, 8760 HR/YR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

1.4.2 Boiler Forms (Form EU5)

The forms included in this section are for the following boilers:

Source Name	Source ID	Source Name	Source ID
Germination Vessel Boiler 1	GVB1	Germination Vessel Boiler 4	GVB4
Germination Vessel Boiler 2	GVB2	Germination Vessel Boiler 5	GVB5
Germination Vessel Boiler 3	GVB3	Germination Vessel Boiler 6	GVB6

Germination Vessel Boilers 1, 2 and 3 will serve two germination vessels (GV1 & GV2) but only two boilers will operate at a time with one boiler as backup.

A similar operation plan applies to Germination Vessel Boilers 4, 5 and 6. Only two boilers will operate at a time with the third boiler as backup.

Manufacturer's information on the new boilers is provided in Appendix C.

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Emissions Units - Industrial Boiler Information **Form EU5**
Revision 5
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name:	2. Facility Name:	3 Facility ID No:
Great Western Malting Company	Great Western Malting Pocatello Plant	005-00035
4. Brief Project Description:	Adding malting capacity with 6 new hot water boilers	

EXEMPTION

Please see IDAPA 58.01.01.222 for a list of industrial boilers that are exempt from Permit to Construct requirements.

BOILER (EMISSION UNIT) DESCRIPTION AND SPECIFICATIONS

5. Type of Request: ☒ New Unit ☐ Unpermitted Existing Unit ☐ Modification to a Unit with Permit #:

6. Use of Boiler: ☒ % Used For Process ☐ % Used For Space Heat ☐ % Used For Generating Electricity ☐ Other:

7. Boiler ID Number: GVB1	8. Rated Capacity: ☒ 2.0 Million British Thermal Units Per Hour (MMBtu/hr) ☐ 1,000 Pounds Steam Per Hour (1,000 lb steam/hr)	
9. Construction Date: 2016	10. Manufacturer: Thermal Solutions	11. Model: EVA-2000
12. Date of Modification (if applicable): N/A	13. Serial Number (if available): TBD	14. Control Device (if any): None **Note: Attach applicable control equipment form(s)**

FUEL DESCRIPTION AND SPECIFICATIONS

15. Fuel Type	☐ Diesel Fuel (#) (gal/hr)	☒ Natural Gas x (cf/hr)	☐ Coal (unit: /hr)	☐ Other Fuels (unit: /hr)
16. Full Load Consumption Rate		1950 cf/hr		
17. Actual Consumption Rate		1950 cf/hr		
18. Fuel Heat Content (Btu/unit, LHV)		1026		
19. Sulfur Content wt%		unk		
20. Ash Content wt%		N/A		

STEAM DESCRIPTION AND SPECIFICATIONS

21. Steam Heat Content	NA	NA		
22. Steam Temperature (^oF)	N/A	N/A		
23. Steam Pressure (psi)	N/A	N/A		
24 Steam Type	N/A	N/A	☐ Saturated ☐ Superheated	☐ Saturated ☐ Superheated

OPERATING LIMITS & SCHEDULE

25. Imposed Operating Limits (hours/year, or gallons fuel/year, etc.):			Will not operate if both GVB2 and GVB3 boilers are operating
26. Operating Schedule (hours/day, months/year, etc.):			24 hr/day, 12 mo/yr, 365 day/yr
27. NSPS Applicability:	☐ Yes ☒ No	If Yes, which subpart:	N/A

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Emissions Units - Industrial Boiler Information **Form EU5**
Revision 5
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name:	2. Facility Name:	3 Facility ID No:
Great Western Malting Company	Great Western Malting Pocatello Plant	005-00035
4. Brief Project Description:	Adding malting capacity with 6 new hot water boilers	

EXEMPTION

Please see IDAPA 58.01.01.222 for a list of industrial boilers that are exempt from Permit to Construct requirements.

BOILER (EMISSION UNIT) DESCRIPTION AND SPECIFICATIONS

5. Type of Request:	☒ New Unit ☐ Unpermitted Existing Unit ☐ Modification to a Unit with Permit #:	
6. Use of Boiler:	☒ % Used For Process ☐ % Used For Space Heat ☐ % Used For Generating Electricity ☐ Other:	
7. Boiler ID Number: GVB2	8. Rated Capacity: ☒ 2.0 Million British Thermal Units Per Hour (MMBtu/hr) ☐ 1,000 Pounds Steam Per Hour (1,000 lb steam/hr)	
9. Construction Date: 2016	10. Manufacturer: Thermal Solutions	11. Model: EVA-2000
12. Date of Modification (if applicable): N/A	13. Serial Number (if available): TBD	14. Control Device (if any): None **Note: Attach applicable control equipment form(s)**

FUEL DESCRIPTION AND SPECIFICATIONS

15. Fuel Type	☐ Diesel Fuel (#) (gal/hr)	☒ Natural Gas x (cf/hr)	☐ Coal (unit: /hr)	☐ Other Fuels (unit: /hr)
16. Full Load Consumption Rate		1950 cf/hr		
17. Actual Consumption Rate		1950 cf/hr		
18. Fuel Heat Content (Btu/unit, LHV)		1026		
19. Sulfur Content wt%		unk		
20. Ash Content wt%		N/A		

STEAM DESCRIPTION AND SPECIFICATIONS

21. Steam Heat Content	NA	NA		
22. Steam Temperature (^{o}F)	N/A	N/A		
23. Steam Pressure (psi)	N/A	N/A		
24 Steam Type	N/A	N/A	☐ Saturated ☐ Superheated	☐ Saturated ☐ Superheated

OPERATING LIMITS & SCHEDULE

25. Imposed Operating Limits (hours/year, or gallons fuel/year, etc.):			Will not operate if GVB1 and GVB3 boilers are operating
26. Operating Schedule (hours/day, months/year, etc.):			24 hr/day, 12 mo/yr, 365 day/yr
27. NSPS Applicability:	☐ Yes ☒ No	If Yes, which subpart:	N/A

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Emissions Units - Industrial Boiler Information **Form EU5**
Revision 5
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION		
1. Company Name:	2. Facility Name:	3 Facility ID No:
Great Western Malting Company	Great Western Malting Pocatello Plant	005-00035
4. Brief Project Description:	Adding malting capacity with 6 new hot water boilers	

EXEMPTION

Please see IDAPA 58.01.01.222 for a list of industrial boilers that are exempt from Permit to Construct requirements.

BOILER (EMISSION UNIT) DESCRIPTION AND SPECIFICATIONS

5. Type of Request:	☒ New Unit ☐ Unpermitted Existing Unit ☐ Modification to a Unit with Permit #:	
6. Use of Boiler:	☒ % Used For Process ☐ % Used For Space Heat ☐ % Used For Generating Electricity ☐ Other:	
7. Boiler ID Number: GVB3	8. Rated Capacity: ☒ 2.0 Million British Thermal Units Per Hour (MMBtu/hr) ☐ 1,000 Pounds Steam Per Hour (1,000 lb steam/hr)	
9. Construction Date: 2016	10. Manufacturer: Thermal Solutions	11. Model: EVA-2000
12. Date of Modification (if applicable): N/A	13. Serial Number (if available): TBD	14. Control Device (if any): None **Note: Attach applicable control equipment form(s)**

FUEL DESCRIPTION AND SPECIFICATIONS

15. Fuel Type	☐ Diesel Fuel (#) (gal/hr)	☒ Natural Gas x (cf/hr)	☐ Coal (unit: /hr)	☐ Other Fuels (unit: /hr)
16. Full Load Consumption Rate		1950 cf/hr		
17. Actual Consumption Rate		1950 cf/hr		
18. Fuel Heat Content (Btu/unit, LHV)		1026		
19. Sulfur Content wt%		unk		
20. Ash Content wt%		N/A		

STEAM DESCRIPTION AND SPECIFICATIONS

21. Steam Heat Content	NA	NA		
22. Steam Temperature (^{o}F)	N/A	N/A		
23. Steam Pressure (psi)	N/A	N/A		
24 Steam Type	N/A	N/A	☐ Saturated ☐ Superheated	☐ Saturated ☐ Superheated

OPERATING LIMITS & SCHEDULE

25. Imposed Operating Limits (hours/year, or gallons fuel/year, etc.):			Will not operate if GVB1 and GVB2 boilers are operating
26. Operating Schedule (hours/day, months/year, etc.):			24 hr/day, 12 mo/yr, 365 day/yr
27. NSPS Applicability:	☐ Yes ☒ No	If Yes, which subpart:	N/A

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Emissions Units - Industrial Boiler Information **Form EU5**
Revision 5
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION		
1. Company Name:	2. Facility Name:	3 Facility ID No:
Great Western Malting Company	Great Western Malting Pocatello Plant	005-00035
4. Brief Project Description:	Adding malting capacity with 6 new hot water boilers	

EXEMPTION

Please see IDAPA 58.01.01.222 for a list of industrial boilers that are exempt from Permit to Construct requirements.

BOILER (EMISSION UNIT) DESCRIPTION AND SPECIFICATIONS		
5. Type of Request: ☒ New Unit ☐ Unpermitted Existing Unit ☐ Modification to a Unit with Permit #:		
6. Use of Boiler: ☒ % Used For Process ☐ % Used For Space Heat ☐ % Used For Generating Electricity ☐ Other:		
7. Boiler ID Number: GVB4	8. Rated Capacity: ☒ 2.0 Million British Thermal Units Per Hour (MMBtu/hr) ☐ 1,000 Pounds Steam Per Hour (1,000 lb steam/hr)	
9. Construction Date: 2016	10. Manufacturer: Thermal Solutions	11. Model: EVA-2000
12. Date of Modification (if applicable): N/A	13. Serial Number (if available): TBD	14. Control Device (if any): None **Note: Attach applicable control equipment form(s)**

FUEL DESCRIPTION AND SPECIFICATIONS

15. Fuel Type	☐ Diesel Fuel (#) (gal/hr)	☒ Natural Gas x (cf/hr)	☐ Coal (unit: /hr)	☐ Other Fuels (unit: /hr)
16. Full Load Consumption Rate		1950 cf/hr		
17. Actual Consumption Rate		1950 cf/hr		
18. Fuel Heat Content (Btu/unit, LHV)		1026		
19. Sulfur Content wt%		unk		
20. Ash Content wt%		N/A		

STEAM DESCRIPTION AND SPECIFICATIONS

21. Steam Heat Content	NA	NA		
22. Steam Temperature (^{o}F)	N/A	N/A		
23. Steam Pressure (psi)	N/A	N/A		
24 Steam Type	N/A	N/A	☐ Saturated ☐ Superheated	☐ Saturated ☐ Superheated

OPERATING LIMITS & SCHEDULE

25. Imposed Operating Limits (hours/year, or gallons fuel/year, etc.):	Will not operate if GVB5 and GVB6 boilers are operating
26. Operating Schedule (hours/day, months/year, etc.):	24 hr/day, 12 mo/yr, 365 day/yr
27. NSPS Applicability: ☐ Yes ☒ No — If Yes, which subpart:	N/A

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Emissions Units - Industrial Boiler Information **Form EU5**
Revision 5
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION		
1. Company Name:	2. Facility Name:	3 Facility ID No:
Great Western Malting Company	Great Western Malting Pocatello Plant	005-00035
4. Brief Project Description:	Adding malting capacity with 6 new hot water boilers	

EXEMPTION

Please see IDAPA 58.01.01.222 for a list of industrial boilers that are exempt from Permit to Construct requirements.

BOILER (EMISSION UNIT) DESCRIPTION AND SPECIFICATIONS

5. Type of Request:	☒ New Unit ☐ Unpermitted Existing Unit ☐ Modification to a Unit with Permit #:	
6. Use of Boiler:	☒ % Used For Process ☐ % Used For Space Heat ☐ % Used For Generating Electricity ☐ Other:	
7. Boiler ID Number: GVB5	8. Rated Capacity: ☒ 2.0 Million British Thermal Units Per Hour (MMBtu/hr) ☐ 1,000 Pounds Steam Per Hour (1,000 lb steam/hr)	
9. Construction Date: 2016	10. Manufacturer: Thermal Solutions	11. Model: EVA-2000
12. Date of Modification (if applicable): N/A	13. Serial Number (if available): TBD	14. Control Device (if any): None **Note: Attach applicable control equipment form(s)**

FUEL DESCRIPTION AND SPECIFICATIONS

15. Fuel Type	☐ Diesel Fuel (#) (gal/hr)	☒ Natural Gas x (cf/hr)	☐ Coal (unit: /hr)	☐ Other Fuels (unit: /hr)
16. Full Load Consumption Rate		1950 cf/hr		
17. Actual Consumption Rate		1950 cf/hr		
18. Fuel Heat Content (Btu/unit, LHV)		1026		
19. Sulfur Content wt%		unk		
20. Ash Content wt%		N/A		

STEAM DESCRIPTION AND SPECIFICATIONS

21. Steam Heat Content	NA	NA		
22. Steam Temperature (°F)	N/A	N/A		
23. Steam Pressure (psi)	N/A	N/A		
24 Steam Type	N/A	N/A	☐ Saturated ☐ Superheated	☐ Saturated ☐ Superheated

OPERATING LIMITS & SCHEDULE

25. Imposed Operating Limits (hours/year, or gallons fuel/year, etc.):		Will not operate if GVB4 and GVB6 boilers are operating
26. Operating Schedule (hours/day, months/year, etc.):		24 hr/day, 12 mo/yr, 365 day/yr
27. NSPS Applicability: ☐ Yes ☒ No	If Yes, which subpart:	N/A

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Emissions Units - Industrial Boiler Information **Form EU5**
Revision 5
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION		
1. Company Name: Great Western Malting Company	2. Facility Name: Great Western Malting Pocatello Plant	3 Facility ID No: 005-00035
4. Brief Project Description:	Adding malting capacity with 6 new hot water boilers	

EXEMPTION

Please see IDAPA 58.01.01.222 for a list of industrial boilers that are exempt from Permit to Construct requirements.

BOILER (EMISSION UNIT) DESCRIPTION AND SPECIFICATIONS		
5. Type of Request:	☒ New Unit ☐ Unpermitted Existing Unit ☐ Modification to a Unit with Permit #:	
6. Use of Boiler:	☒ % Used For Process ☐ % Used For Space Heat ☐ % Used For Generating Electricity ☐ Other:	
7. Boiler ID Number: GVB6	8. Rated Capacity: ☒ 2.0 Million British Thermal Units Per Hour (MMBtu/hr) ☐ 1,000 Pounds Steam Per Hour (1,000 lb steam/hr)	
9. Construction Date: 2016	10. Manufacturer: Thermal Solutions	11. Model: EVA-2000
12. Date of Modification (if applicable): N/A	13. Serial Number (if available): TBD	14. Control Device (if any): None **Note: Attach applicable control equipment form(s)**

FUEL DESCRIPTION AND SPECIFICATIONS				
15. Fuel Type	☐ Diesel Fuel (#) (gal/hr)	☒ Natural Gas x (cf/hr)	☐ Coal (unit: /hr)	☐ Other Fuels (unit: /hr)
16. Full Load Consumption Rate		1950 cf/hr		
17. Actual Consumption Rate		1950 cf/hr		
18. Fuel Heat Content (Btu/unit, LHV)		1026		
19. Sulfur Content wt%		unk		
20. Ash Content wt%		N/A		

STEAM DESCRIPTION AND SPECIFICATIONS				
21. Steam Heat Content	NA	NA		
22. Steam Temperature (^oF)	N/A	N/A		
23. Steam Pressure (psi)	N/A	N/A		
24 Steam Type	N/A	N/A	☐ Saturated ☐ Superheated	☐ Saturated ☐ Superheated

OPERATING LIMITS & SCHEDULE			
25. Imposed Operating Limits (hours/year, or gallons fuel/year, etc.):			Will not operate if GVB4 and GVB5 boilers are operating
26. Operating Schedule (hours/day, months/year, etc.):			24 hr/day, 12 mo/yr, 365 day/yr
27. NSPS Applicability:	☐ Yes ☒ No	If Yes, which subpart:	N/A

1.4.3 Cyclone Form (CYS)

The form included in this section is for the new kiln by-product cyclone (KBPC).

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For assistance, call the
Air Permit Hotline: 1-877-5PERMIT

Cyclone Separator - **Form CYS**
Revision 2
08/28/08

Please see instructions on page 3 before filling out the form.

IDENTIFICATION

1. Company Name:	Great Western Malting Company	2. Facility Name:	Great Western Malting Pocatello Plant	3. Facility ID No.:	005-00035
4. Brief Project Description:	Adding malting capacity to the Pocatello plan This cyclone will handle by-products from the new kiln (ID: KBPC)				

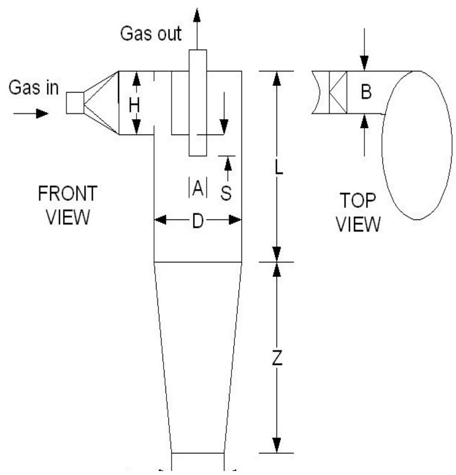
CYCLONE SEPARATOR INFORMATION

Equipment Description

5. Manufacturer: Donaldson Cyclone

6. Model Number: HV-14

7. Dimensions



Give dimensions of cyclone. (See sample diagram above.)

1. B: 3 in.	5. Z: 16 in.
2. H: 7 in.	6. D: 14 in.
3. S: 2 in.	7. A: 3 in.
4. L: 27 in.	8. J: 4 in.

8. Particulate Size Distribution Data

Micron range	Particle size distribution weight %	Manufacturer's guaranteed removal efficiency for each micron range
0.5-1.0		20-40%
1.0-5.0		40-80%
5-10		80-90%
10-20		90%+
Over 20		90%+

9. Type of Cyclone: ☐ Wet ☒ Dry

10. Type of Cyclone Unit: ☒ Single ☐ Quadruple ☐ Dual ☐ Multiclone

11. Blower: Blower horsepower: 2 hp
Design flow rate: 390 scfm
Draft: ☐ Forced ☒ Induced

12. Design Criteria: Cyclone configuration: ☒ Positive pressure ☐ Negative pressure

13. Pre-Treatment Device: ☐ Cyclone ☐ Knock-out chamber ☐ Precooler ☒ None ☐ Preheater

14. Post-Treatment Device: ☐ Baghouse/Cartridge ☐ HEPA ☒ Other: KBPCF- filter

Process Stream Characteristics	
15. Brief Description of Process	.By-products from the new malt kiln will be pneumatically conveyed to this cyclone. This kiln by-products cyclone (KBPC) will separate the by-products solids out of the air stream and discharge the solids into a by-products storage bin. Air from the KBPC will be vented to a dust filter (KBPCF) for particulate control.
16. Flow Data	Gas stream temperature: 70 degrees F Moisture content: Ambient grams of water/cubic feet (ft^3) of dry air <u>Pressure drop range</u> High: 3 in. H_2O Low: 1 in. H_2O Dew point temperature of process stream: degrees F Inlet flow rate: 390 ACFM
17. Dust Collection Device	☒ Pneumatic conveyor ☐ Rotary airlock values ☐ Screw conveyors ☐ Closed container ☐ Double dump ☐ Drag conveyor ☐ Manual discharge device: ☐ Slide gate OR ☐ Hinged doors or drawers
18. Operating Schedule	Normal: hours/day days/week weeks/year Maximum: 24 hours/day 7 days/week 52 weeks/year

1.4.4 Engine Form (Form EU1)

The form included in this section is for the existing emergency generator (EG1). This generator has been onsite since 1980 and is included in this application so that it can be incorporated into the air permit for the plant.

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For assistance, call the
Air Permit Hotline – 1-877-5PERMIT

Emissions Units Industrial IC Engine Information - **Form EU1**
Revision 9
10/23/13

Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name	2. Facility Name:
Great Western Malting Company	Great Western Malting Pocatello Plant Facility ID: 005-00035

3. Brief Project Description:	Adding malting capacity to Pocatello plant Including existing emergency generator (EG1) as an emission source into permit

IC ENGINE DESCRIPTION AND SPECIFICATIONS

4. Type of unit:
- ☐ New unit ☐ Unpermitted existing unit ☒ Modification to an existing permitted unit? Permit number: ________
- ☐ Full-time operation (non-emergency standby use)?
- ☒ Emergency standby use only (operation limited to 100 hrs/yr for maintenance and testing and emergency use only)?
- ☐ Emergency fire pump use only?
- ☐ Stationary test cell/stand operation only (as defined in NSPS Subpart ZZZZ)?
- ☐ National security operation only (as defined in NSPS Subpart ZZZZ)?
- ☐ Institutional emergency standby IC engine (as defined in NSPS Subpart ZZZZ)?

IC ENGINE SPECIFICATIONS

Questions 5 through 15 apply to **all IC engines**.

5. IC Engine Manufacturer: Kohler 6. Model: 45ROZ71 7. Date manufactured: 1980 8. Model year: 1980
9. Date of installation (if an existing IC engine): 1980 10. IC Engine cylinder displacement: 56 liters per cylinder
11. Maximum rated horsepower (per the data plate/manufacturer specifications): 60 bhp
12. EPA Certification: Tier certification number ________ or ☒ None/not tier certified
13. Ignition type: ☐ Spark ☒ Compression
14. Fuel combusted in the IC engine? ☒ Distillate fuel oil ☐ Natural gas/LNG ☐ LPG/propane
If distillate fuel oil (#1, #2, or a mixture) is used, what is the maximum sulfur content? ☒ 15 ppm (0.0015% by weight) ☐ 500 ppm (0.05% by weight)
15. IC engine exhaust stack parameters: Diameter 4 inches Height 6 feet Temperature 600 °F Flow rate 400 acfm

IC ENGINE EMISSIONS PARAMETERS

Questions 16 through 27 apply to **full-time** non-Tier certified IC engines or Tier certified IC engines manufactured prior to July 11, 2005. If you are proposing a Tier certified IC engine manufactured on and after July 11, 2005 or an emergency standby IC engine do not answer questions 17 through 27.

16. Testing schedule (for emergency standby IC engines only): 1 hrs/day 1 hrs/mon 3 hrs/qtr 12 hrs/yr
17. Maximum daily operation: na hrs/day 18. Maximum annual operation: na hrs/yr **Note:** These operational limits will be placed in the permit.
19. Will CO emissions be limited to a specific ppmvd (i.e. 49 or 23 ppmvd)? ☐ Yes ☒ No 20. What will the CO emissions limit be? ________ ppmvd
21. Will CO emissions be reduced by 70% or more? ☐ Yes ☒ No
22. Will a CEMS (Continuous Emissions Monitoring System) be used to measure pollutants in the IC engine exhaust stream? ☐ Yes ☒ No
23. Will a CPMS (Continuous Parameters Monitoring System) be used to measure parameters of the IC engine exhaust stream? ☐ Yes ☒ No
24. Will the IC engine be equipped with an oxidation catalyst? ☐ Yes ☒ No
25. If applicable, will the oxidation catalyst be equipped with a temperature measurement system to ensure it is operating properly? ☐ Yes ☐ No
26. Will the IC engine be equipped with a diesel particulate filter? ☐ Yes ☒ No
27. If applicable, will the diesel particulate filter be equipped with a backpressure monitor that notifies the owner or operator when the high backpressure limit of the engine is approached? ☐ Yes ☐ No

1.4.5 Dust Filter Forms (Forms BCE)

There will be ten new filters added to the material handling and storage equipment for air pollution control. The forms included in this section are for the following dust filters:

APCD Name	APCD ID	APCD Name	APCD ID
Steep Tank Conveyor 1 Filter	STC1F	Kiln By-Product Cyclone Filter	KBPCF
Steep Tank Conveyor 2 Filter	STC2F	New Malt Conveyor 3 Filter	NMC3F
New Malt Leg Filter	NMLF	Micro Bins Conveyor Filter	MBCF
Analysis Bin 1 Filter	BA1F	New Malt Storage Bins Conveyor 1 Filter	NMSBC1F
Analysis Bin 2 Filter	BA2F	New Malt Storage Bins Conveyor 2 Filter	NMSBC2F

Note that the air flow rates listed in the filter forms are presented in actual cubic feet per minute (acfm). Because the air being filtered is at ambient conditions and because there is very little moisture in the grain and malt, the difference between acfm and dry standard cubic feet per minute (dscfm) should be minor.

The air flow rate estimates are engineering estimates that were developed based on the quantity of air being displaced by the product moving through the equipment. The displaced air flows were then multiplied by a safety factor of 1.5 to account for some variability in the new systems. The resulting air flows are presented in the following table:

Table 1-2: Dust Filter Flow Rates

Stack #	Equipment Name	Description	Existing Conditions CFM	Safety Factor	Total ACFM
S1	STC1F	Spot filter on transfer conveyor from Barley to Steeps	190	1.5	285
S2	STC2F	Spot filter on conveyor above the steeps	190	1.5	285
S32	NMLF	Spot filter on discharge from the kiln	1000	1.5	1500
S33	BA1F	Analysis Bin Spot Filter	260	1.5	390
S34	BA2F	Analysis Bin Spot Filter	260	1.5	390
S35	KBPCF	Byproduct Cyclone Spot Filter	260	1.5	390
S36	NMC3F	Spot Filter on tranfer conveyor to Kiln Tunnel	190	1.5	285
S37	MBCF	Micro Bin Spot Filter	65	1.5	97.5
S46	NMSBC1F	Malt Storage Spot Filter	190	1.5	285
S47	NMSBC2F	Malt Storage Spot Filter	190	1.5	285

All of the new dust filters will be part of the Donaldson Torit Powercore CP Series. The filter (NMLF) for the New Malt Leg conveyor will be a CPV3 model. The remaining nine filters all will be CPV1 models. Manufacturer's information on the dust filters is provided in Appendix D.

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Baghouse Control Equipment **Form BCE**
Revision 6
2/18/10

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IDENTIFICATION

1. Company Name	2. Facility Name:
Great Western Malting	Great Western Malting Pocatello Plant

3. Brief Project Description: Adding malting capacity to the Pocatello Plant
Project will add new dust filter for controlling PM10/PM2.5 emissions from Steep Tanks Conveyor 1

BAGHOUSE INFORMATION

4. Baghouse Manufacturer: Donaldson Torit	5. Baghouse Model: CPV1	6. Baghouse Equipment ID: STC1F

7 (a). Baghouse particulate matter emission concentration. **Note: Provide information in 7(a)-(c) or answer question #8 below.**	0.002 gr/dscf	*Manufacturers typically provide guarantees in grains per dry standard cubic foot (gr/dscf). Provide a copy of the guarantee, or other documentation, with the application along with a description of the types of bags that must be used to achieve the emission concentration.* ***Emission concentrations less than 0.01 gr/dscf will receive additional scrutiny by DEQ and a source test of the baghouse may be required.*** *If a guarantee is not provided then you must document how you obtained the emission concentration. Without documentation the application is not complete.*
7 (b). Percentage PM_{10} Or Provide PM_{10} Emission Concentration	_____ % 0.002 gr/dscf	*What percentage of the PM concentration listed in question #7(a) is PM_{10}. You must provide documentation as to how the percentage was determined (i.e per the baghouse manufacturer). Without documentation the application is not complete.*
7 (c). Baghouse flow rate	285 dscfm	*Provide the baghouse flow rate in dry standard cubic feet per minute. Actual cubic feet per minute may be given in lieu of dscfm* ***if it is documented*** *that moisture content is insignificant. You must provide documentation as to how this flow rate was determined (i.e. per the exhaust fan manufacturer, combustion evaluation, etc.). Without documentation the application is not complete.*
8. Baghouse particulate matter control efficiency. **Note: Not needed if section #7 is completed.**	_____ % PM control _____ % PM_{10} control	*Applicant's providing the control efficiency of the baghouse must provide control efficiency for both PM and PM_{10}. Provide a copy of the control efficiency documentation with the application. Documentation must include a description of the types of bags that must be used to achieve the control efficiency. Without documentation the application is not complete.*
9. Is the baghouse equipped with a bag leak detector?	☐ Yes ☒ No	*If a bag leak detector is installed provide documentation on the leak detector, including; how the leak detector functions and what level of the output signal indicates that a bag is leaking. Without documentation the application is not complete.*

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Revision 6
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3. Brief Project Description: Adding malting capacity to the Pocatello Plant
Project will add new dust filter for controlling PM10/PM2.5 emissions from Steep Tanks Conveyor 2

BAGHOUSE INFORMATION

4. Baghouse Manufacturer: Donaldson Torit	5. Baghouse Model: CPV1	6. Baghouse Equipment ID: STC2F

7 (a). Baghouse particulate matter emission concentration. **Note: Provide information in 7(a)-(c) or answer question #8 below.**	0.002 gr/dscf	*Manufacturers typically provide guarantees in grains per dry standard cubic foot (gr/dscf). Provide a copy of the guarantee, or other documentation, with the application along with a description of the types of bags that must be used to achieve the emission concentration.* ***Emission concentrations less than 0.01 gr/dscf will receive additional scrutiny by DEQ and a source test of the baghouse may be required.*** *If a guarantee is not provided then you must document how you obtained the emission concentration. Without documentation the application is not complete.*
7 (b). Percentage PM_{10} Or Provide PM_{10} Emission Concentration	_____ % 0.002 gr/dscf	*What percentage of the PM concentration listed in question #7(a) is PM_{10}. You must provide documentation as to how the percentage was determined (i.e per the baghouse manufacturer). Without documentation the application is not complete.*
7 (c). Baghouse flow rate	285 dscfm	*Provide the baghouse flow rate in dry standard cubic feet per minute. Actual cubic feet per minute may be given in lieu of dscfm* ***if it is documented*** *that moisture content is insignificant. You must provide documentation as to how this flow rate was determined (i.e. per the exhaust fan manufacturer, combustion evaluation, etc.). Without documentation the application is not complete.*
8. Baghouse particulate matter control efficiency. **Note: Not needed if section #7 is completed.**	_____ % PM control _____ % PM_{10} control	*Applicant's providing the control efficiency of the baghouse must provide control efficiency for both PM and PM_{10}. Provide a copy of the control efficiency documentation with the application. Documentation must include a description of the types of bags that must be used to achieve the control efficiency. Without documentation the application is not complete.*
9. Is the baghouse equipped with a bag leak detector?	☐ Yes ☒ No	*If a bag leak detector is installed provide documentation on the leak detector, including; how the leak detector functions and what level of the output signal indicates that a bag is leaking. Without documentation the application is not complete.*

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Revision 6
2/18/10

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IDENTIFICATION

1. Company Name	2. Facility Name:
Great Western Malting	Great Western Malting Pocatello Plant

3. Brief Project Description:	Adding malting capacity to the Pocatello Plant Project will add new dust filter for controlling PM10/PM2.5 emissions from New Malt Leg conveyor

BAGHOUSE INFORMATION

4. Baghouse Manufacturer: Donaldson Torit	5. Baghouse Model: CPV3	6. Baghouse Equipment ID: NMLF

7 (a). Baghouse particulate matter emission concentration. **Note: Provide information in 7(a)-(c) or answer question #8 below.**	0.002 gr/dscf	*Manufacturers typically provide guarantees in grains per dry standard cubic foot (gr/dscf). Provide a copy of the guarantee, or other documentation, with the application along with a description of the types of bags that must be used to achieve the emission concentration.* ***Emission concentrations less than 0.01 gr/dscf will receive additional scrutiny by DEQ and a source test of the baghouse may be required.*** *If a guarantee is not provided then you must document how you obtained the emission concentration. Without documentation the application is not complete.*
7 (b). Percentage PM_{10} Or Provide PM_{10} Emission Concentration	_____ % 0.002 gr/dscf	*What percentage of the PM concentration listed in question #7(a) is PM_{10}. You must provide documentation as to how the percentage was determined (i.e per the baghouse manufacturer). Without documentation the application is not complete.*
7 (c). Baghouse flow rate	1500 dscfm	*Provide the baghouse flow rate in dry standard cubic feet per minute. Actual cubic feet per minute may be given in lieu of dscfm* ***if it is documented*** *that moisture content is insignificant. You must provide documentation as to how this flow rate was determined (i.e. per the exhaust fan manufacturer, combustion evaluation, etc.). Without documentation the application is not complete.*
8. Baghouse particulate matter control efficiency. **Note: Not needed if section #7 is completed.**	_____ % PM control _____ % PM_{10} control	*Applicant's providing the control efficiency of the baghouse must provide control efficiency for both PM and PM_{10}. Provide a copy of the control efficiency documentation with the application. Documentation must include a description of the types of bags that must be used to achieve the control efficiency. Without documentation the application is not complete.*
9. Is the baghouse equipped with a bag leak detector?	☐ Yes ☒ No	*If a bag leak detector is installed provide documentation on the leak detector, including; how the leak detector functions and what level of the output signal indicates that a bag is leaking. Without documentation the application is not complete.*

DEQ AIR QUALITY PROGRAM
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Baghouse Control Equipment **Form BCE**
Revision 6
2/18/10

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IDENTIFICATION

1. Company Name	2. Facility Name:
Great Western Malting	Great Western Malting Pocatello Plant

3. Brief Project Description: Adding malting capacity to the Pocatello Plant
Project will add new dust filter for controlling PM10/PM2.5 emissions from Analysis Bin 1 fill

BAGHOUSE INFORMATION

4. Baghouse Manufacturer: Donaldson Torit	5. Baghouse Model: CPV1	6. Baghouse Equipment ID: BA1F

7 (a). Baghouse particulate matter emission concentration. **Note: Provide information in 7(a)-(c) or answer question #8 below.**	0.002 gr/dscf	*Manufacturers typically provide guarantees in grains per dry standard cubic foot (gr/dscf). Provide a copy of the guarantee, or other documentation, with the application along with a description of the types of bags that must be used to achieve the emission concentration.* ***Emission concentrations less than 0.01 gr/dscf will receive additional scrutiny by DEQ and a source test of the baghouse may be required.*** *If a guarantee is not provided then you must document how you obtained the emission concentration. Without documentation the application is not complete.*
7 (b). Percentage PM_{10} Or Provide PM_{10} Emission Concentration	_____ % 0.002 gr/dscf	*What percentage of the PM concentration listed in question #7(a) is PM_{10}. You must provide documentation as to how the percentage was determined (i.e per the baghouse manufacturer). Without documentation the application is not complete.*
7 (c). Baghouse flow rate	390 dscfm	*Provide the baghouse flow rate in dry standard cubic feet per minute. Actual cubic feet per minute may be given in lieu of dscfm* ***if it is documented*** *that moisture content is insignificant. You must provide documentation as to how this flow rate was determined (i.e. per the exhaust fan manufacturer, combustion evaluation, etc.). Without documentation the application is not complete.*
8. Baghouse particulate matter control efficiency. **Note: Not needed if section #7 is completed.**	_____ % PM control _____ % PM_{10} control	*Applicant's providing the control efficiency of the baghouse must provide control efficiency for both PM and PM_{10}. Provide a copy of the control efficiency documentation with the application. Documentation must include a description of the types of bags that must be used to achieve the control efficiency. Without documentation the application is not complete.*
9. Is the baghouse equipped with a bag leak detector?	☐ Yes ☒ No	*If a bag leak detector is installed provide documentation on the leak detector, including; how the leak detector functions and what level of the output signal indicates that a bag is leaking. Without documentation the application is not complete.*

DEQ AIR QUALITY PROGRAM
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Baghouse Control Equipment **Form BCE**
Revision 6
2/18/10

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1. Company Name	2. Facility Name:
Great Western Malting	Great Western Malting Pocatello Plant

3. Brief Project Description: Adding malting capacity to the Pocatello Plant
Project will add new dust filter for controlling PM10/PM2.5 emissions from Analysis Bin 2 fill

BAGHOUSE INFORMATION

4. Baghouse Manufacturer: Donaldson Torit	5. Baghouse Model: CPV1	6. Baghouse Equipment ID: BA2F

7 (a). Baghouse particulate matter emission concentration. **Note: Provide information in 7(a)-(c) or answer question #8 below.**	0.002 gr/dscf	*Manufacturers typically provide guarantees in grains per dry standard cubic foot (gr/dscf). Provide a copy of the guarantee, or other documentation, with the application along with a description of the types of bags that must be used to achieve the emission concentration.* ***Emission concentrations less than 0.01 gr/dscf will receive additional scrutiny by DEQ and a source test of the baghouse may be required.*** *If a guarantee is not provided then you must document how you obtained the emission concentration. Without documentation the application is not complete.*
7 (b). Percentage PM_{10} Or Provide PM_{10} Emission Concentration	_____ % 0.002 gr/dscf	*What percentage of the PM concentration listed in question #7(a) is PM_{10}. You must provide documentation as to how the percentage was determined (i.e per the baghouse manufacturer). Without documentation the application is not complete.*
7 (c). Baghouse flow rate	390 dscfm	*Provide the baghouse flow rate in dry standard cubic feet per minute. Actual cubic feet per minute may be given in lieu of dscfm* ***if it is documented*** *that moisture content is insignificant. You must provide documentation as to how this flow rate was determined (i.e. per the exhaust fan manufacturer, combustion evaluation, etc.). Without documentation the application is not complete.*
8. Baghouse particulate matter control efficiency. **Note: Not needed if section #7 is completed.**	_____ % PM control _____ % PM_{10} control	*Applicant's providing the control efficiency of the baghouse must provide control efficiency for both PM and PM_{10}. Provide a copy of the control efficiency documentation with the application. Documentation must include a description of the types of bags that must be used to achieve the control efficiency. Without documentation the application is not complete.*
9. Is the baghouse equipped with a bag leak detector?	☐ Yes ☒ No	*If a bag leak detector is installed provide documentation on the leak detector, including; how the leak detector functions and what level of the output signal indicates that a bag is leaking. Without documentation the application is not complete.*

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Baghouse Control Equipment **Form BCE**
Revision 6
2/18/10

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1. Company Name	2. Facility Name:
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3. Brief Project Description: Adding malting capacity to the Pocatello Plant
Project will add new dust filter for controlling PM10/PM2.5 emissions from Kiln By-Products Cyclone

BAGHOUSE INFORMATION

4. Baghouse Manufacturer: Donaldson Torit	5. Baghouse Model: CPV1	6. Baghouse Equipment ID: KBPCF

7 (a). Baghouse particulate matter emission concentration. **Note: Provide information in 7(a)-(c) or answer question #8 below.**	0.002 gr/dscf	*Manufacturers typically provide guarantees in grains per dry standard cubic foot (gr/dscf). Provide a copy of the guarantee, or other documentation, with the application along with a description of the types of bags that must be used to achieve the emission concentration.* ***Emission concentrations less than 0.01 gr/dscf will receive additional scrutiny by DEQ and a source test of the baghouse may be required.*** *If a guarantee is not provided then you must document how you obtained the emission concentration. Without documentation the application is not complete.*
7 (b). Percentage PM_{10} Or Provide PM_{10} Emission Concentration	_____ % 0.002 gr/dscf	*What percentage of the PM concentration listed in question #7(a) is PM_{10}. You must provide documentation as to how the percentage was determined (i.e per the baghouse manufacturer). Without documentation the application is not complete.*
7 (c). Baghouse flow rate	390 dscfm	*Provide the baghouse flow rate in dry standard cubic feet per minute. Actual cubic feet per minute may be given in lieu of dscfm* ***if it is documented*** *that moisture content is insignificant. You must provide documentation as to how this flow rate was determined (i.e. per the exhaust fan manufacturer, combustion evaluation, etc.). Without documentation the application is not complete.*
8. Baghouse particulate matter control efficiency. **Note: Not needed if section #7 is completed.**	_____ % PM control _____ % PM_{10} control	*Applicant's providing the control efficiency of the baghouse must provide control efficiency for both PM and PM_{10}. Provide a copy of the control efficiency documentation with the application. Documentation must include a description of the types of bags that must be used to achieve the control efficiency. Without documentation the application is not complete.*
9. Is the baghouse equipped with a bag leak detector?	☐ Yes ☒ No	*If a bag leak detector is installed provide documentation on the leak detector, including; how the leak detector functions and what level of the output signal indicates that a bag is leaking. Without documentation the application is not complete.*

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Baghouse Control Equipment **Form BCE**
Revision 6
2/18/10

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1. Company Name	2. Facility Name:
Great Western Malting	Great Western Malting Pocatello Plant

3. Brief Project Description: Adding malting capacity to the Pocatello Plant
Project will add new dust filter for controlling PM10/PM2.5 emissions from New Malt Conveyor 3

BAGHOUSE INFORMATION

4. Baghouse Manufacturer: Donaldson Torit	5. Baghouse Model: CPV1	6. Baghouse Equipment ID: NMC3F

7 (a). Baghouse particulate matter emission concentration. **Note: Provide information in 7(a)-(c) or answer question #8 below.**	0.002 gr/dscf	*Manufacturers typically provide guarantees in grains per dry standard cubic foot (gr/dscf). Provide a copy of the guarantee, or other documentation, with the application along with a description of the types of bags that must be used to achieve the emission concentration.* ***Emission concentrations less than 0.01 gr/dscf will receive additional scrutiny by DEQ and a source test of the baghouse may be required.*** *If a guarantee is not provided then you must document how you obtained the emission concentration. Without documentation the application is not complete.*
7 (b). Percentage PM_{10} Or Provide PM_{10} Emission Concentration	_____ % 0.002 gr/dscf	*What percentage of the PM concentration listed in question #7(a) is PM_{10}. You must provide documentation as to how the percentage was determined (i.e per the baghouse manufacturer). Without documentation the application is not complete.*
7 (c). Baghouse flow rate	285 dscfm	*Provide the baghouse flow rate in dry standard cubic feet per minute. Actual cubic feet per minute may be given in lieu of dscfm* ***if it is documented*** *that moisture content is insignificant. You must provide documentation as to how this flow rate was determined (i.e. per the exhaust fan manufacturer, combustion evaluation, etc.). Without documentation the application is not complete.*
8. Baghouse particulate matter control efficiency. **Note: Not needed if section #7 is completed.**	_____ % PM control _____ % PM_{10} control	*Applicant's providing the control efficiency of the baghouse must provide control efficiency for both PM and PM_{10}. Provide a copy of the control efficiency documentation with the application. Documentation must include a description of the types of bags that must be used to achieve the control efficiency. Without documentation the application is not complete.*
9. Is the baghouse equipped with a bag leak detector?	☐ Yes ☒ No	*If a bag leak detector is installed provide documentation on the leak detector, including; how the leak detector functions and what level of the output signal indicates that a bag is leaking. Without documentation the application is not complete.*

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Revision 6
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Great Western Malting	Great Western Malting Pocatello Plant

3. Brief Project Description: Adding malting capacity to the Pocatello Plant
Project will add new dust filter for controlling PM10/PM2.5 emissions from Micro Bins fill conveyor

BAGHOUSE INFORMATION

4. Baghouse Manufacturer: Donaldson Torit	5. Baghouse Model: CPV1	6. Baghouse Equipment ID: MBCF

7 (a). Baghouse particulate matter emission concentration. **Note: Provide information in 7(a)-(c) or answer question #8 below.**	0.002 gr/dscf	*Manufacturers typically provide guarantees in grains per dry standard cubic foot (gr/dscf). Provide a copy of the guarantee, or other documentation, with the application along with a description of the types of bags that must be used to achieve the emission concentration.* ***Emission concentrations less than 0.01 gr/dscf will receive additional scrutiny by DEQ and a source test of the baghouse may be required.*** *If a guarantee is not provided then you must document how you obtained the emission concentration. Without documentation the application is not complete.*
7 (b). Percentage PM_{10} Or Provide PM_{10} Emission Concentration	_____ % 0.002 gr/dscf	*What percentage of the PM concentration listed in question #7(a) is PM_{10}. You must provide documentation as to how the percentage was determined (i.e per the baghouse manufacturer). Without documentation the application is not complete.*
7 (c). Baghouse flow rate	97.5 dscfm	*Provide the baghouse flow rate in dry standard cubic feet per minute. Actual cubic feet per minute may be given in lieu of dscfm* ***if it is documented*** *that moisture content is insignificant. You must provide documentation as to how this flow rate was determined (i.e. per the exhaust fan manufacturer, combustion evaluation, etc.). Without documentation the application is not complete.*
8. Baghouse particulate matter control efficiency. **Note: Not needed if section #7 is completed.**	_____ % PM control _____ % PM_{10} control	*Applicant's providing the control efficiency of the baghouse must provide control efficiency for both PM and PM_{10}. Provide a copy of the control efficiency documentation with the application. Documentation must include a description of the types of bags that must be used to achieve the control efficiency. Without documentation the application is not complete.*
9. Is the baghouse equipped with a bag leak detector?	☐ Yes ☒ No	*If a bag leak detector is installed provide documentation on the leak detector, including; how the leak detector functions and what level of the output signal indicates that a bag is leaking. Without documentation the application is not complete.*

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Revision 6
2/18/10

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3. Brief Project Description: Adding malting capacity to the Pocatello Plant
Project will add new dust filter for controlling PM10/PM2.5 emissions from New Malt Storage Bins fill Conveyor 1

BAGHOUSE INFORMATION

4. Baghouse Manufacturer: Donaldson Torit	5. Baghouse Model: CPV1	6. Baghouse Equipment ID: NMSBC1F

7 (a). Baghouse particulate matter emission concentration. **Note: Provide information in 7(a)-(c) or answer question #8 below.**	0.002 gr/dscf	*Manufacturers typically provide guarantees in grains per dry standard cubic foot (gr/dscf). Provide a copy of the guarantee, or other documentation, with the application along with a description of the types of bags that must be used to achieve the emission concentration.* ***Emission concentrations less than 0.01 gr/dscf will receive additional scrutiny by DEQ and a source test of the baghouse may be required.*** *If a guarantee is not provided then you must document how you obtained the emission concentration. Without documentation the application is not complete.*
7 (b). Percentage PM_{10} Or Provide PM_{10} Emission Concentration	_____ % 0.002 gr/dscf	*What percentage of the PM concentration listed in question #7(a) is PM_{10}. You must provide documentation as to how the percentage was determined (i.e per the baghouse manufacturer). Without documentation the application is not complete.*
7 (c). Baghouse flow rate	285 dscfm	*Provide the baghouse flow rate in dry standard cubic feet per minute. Actual cubic feet per minute may be given in lieu of dscfm* ***if it is documented*** *that moisture content is insignificant. You must provide documentation as to how this flow rate was determined (i.e. per the exhaust fan manufacturer, combustion evaluation, etc.). Without documentation the application is not complete.*
8. Baghouse particulate matter control efficiency. **Note: Not needed if section #7 is completed.**	_____ % PM control _____ % PM_{10} control	*Applicant's providing the control efficiency of the baghouse must provide control efficiency for both PM and PM_{10}. Provide a copy of the control efficiency documentation with the application. Documentation must include a description of the types of bags that must be used to achieve the control efficiency. Without documentation the application is not complete.*
9. Is the baghouse equipped with a bag leak detector?	☐ Yes ☒ No	*If a bag leak detector is installed provide documentation on the leak detector, including; how the leak detector functions and what level of the output signal indicates that a bag is leaking. Without documentation the application is not complete.*

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Revision 6
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1. Company Name	2. Facility Name:
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3. Brief Project Description: Adding malting capacity to the Pocatello Plant
Project will add new dust filter for controlling PM10/PM2.5 emissions from New Malt Storage Bins Converor 2

BAGHOUSE INFORMATION

4. Baghouse Manufacturer: Donaldson Torit	5. Baghouse Model: CPV1	6. Baghouse Equipment ID: NMSBC2F

7 (a). Baghouse particulate matter emission concentration. **Note: Provide information in 7(a)-(c) or answer question #8 below.**	0.002 gr/dscf	*Manufacturers typically provide guarantees in grains per dry standard cubic foot (gr/dscf). Provide a copy of the guarantee, or other documentation, with the application along with a description of the types of bags that must be used to achieve the emission concentration.* ***Emission concentrations less than 0.01 gr/dscf will receive additional scrutiny by DEQ and a source test of the baghouse may be required.*** *If a guarantee is not provided then you must document how you obtained the emission concentration. Without documentation the application is not complete.*
7 (b). Percentage PM_{10} Or Provide PM_{10} Emission Concentration	_____ % 0.002 gr/dscf	*What percentage of the PM concentration listed in question #7(a) is PM_{10}. You must provide documentation as to how the percentage was determined (i.e per the baghouse manufacturer). Without documentation the application is not complete.*
7 (c). Baghouse flow rate	285 dscfm	*Provide the baghouse flow rate in dry standard cubic feet per minute. Actual cubic feet per minute may be given in lieu of dscfm* ***if it is documented*** *that moisture content is insignificant. You must provide documentation as to how this flow rate was determined (i.e. per the exhaust fan manufacturer, combustion evaluation, etc.). Without documentation the application is not complete.*
8. Baghouse particulate matter control efficiency. **Note: Not needed if section #7 is completed.**	_____ % PM control _____ % PM_{10} control	*Applicant's providing the control efficiency of the baghouse must provide control efficiency for both PM and PM_{10}. Provide a copy of the control efficiency documentation with the application. Documentation must include a description of the types of bags that must be used to achieve the control efficiency. Without documentation the application is not complete.*
9. Is the baghouse equipped with a bag leak detector?	☐ Yes ☒ No	*If a bag leak detector is installed provide documentation on the leak detector, including; how the leak detector functions and what level of the output signal indicates that a bag is leaking. Without documentation the application is not complete.*

2.0 Process Description

This section of the application contains:

- Project Information
- Construction Schedule
- Process Description

2.1 Project Information

Great Western Malting produces high quality malted barley and other malted grains that are basic ingredients in beer. The company is planning to increase the malting capacity of the Pocatello plant. The plant is located at 1666 Kraft Road in Pocatello, Idaho. The UTM Coordinates of the facility are X: 378.6 km, Y: 4749.8 km.

The processes of the plant can be divided into four main areas:

- Grain Handling (grain receiving, storage, cleaning and conveying);
- Malting (steeping, germination and kilning);
- Malt Handling (storage, cleaning, conveying, and shipping), and
- By-product Handling (pellet making, storage, conveying and shipping).

The proposed project will add a second malting line (i.e., new steeps, new germination vessels and new kiln) plus added malt handling capacity (i.e., new storage bins and shipping bins) to yield an increase in malt production. In addition, the heaters in the existing malt kiln will be replaced.

Only minor changes to the existing grain handling equipment at the plant are planned. The existing equipment is sized to handle the additional grain quantities needed to support the new malting equipment.

The malting expansion project will result in an increase in grain throughput and malt production. The expected maximum production rates are:

Maximum Production After Expansion (MT/year)

Material	Existing	Added	Facility Total
Barley & other grains	144,000	180,000	324,000
Malt	130,000	162,000	292,000
Pelletized/Feed	12,000	15,000	27,000

The plot plan drawing of the site is provided as Figure 3-1. The locations of the stacks associated with the air emission equipment are shown as part of the modeling analysis in Section 7.

2.2 Construction Schedule

The project will be constructed in two phases. Phase 1 includes the construction and testing of the new malting and material handling equipment in the malting expansion.

Phase 2 covers the replacement of the heaters in the existing kiln with new air-to-air heat exchangers.

The approximate start and end dates for the main tasks associated with the Pocatello malting expansion project are:

Phase 1: Malting Expansion
- Foundations and Utilities: December 2015 to May 2016
- Equipment Installations: April 2016 to February 2017
- Start-up Trials: January 2017 to May 2017
- Begin Production: May 2017

Phase 2: Heater Replacement
- Stop Production in Existing Kiln: May 2017
- Heater Installations: May to June 2017
- Begin Production in Existing Kiln: July 2017

2.3 Process Description

2.3.1 Grain Handling

The existing grain handling processes are described in this section of the application. A Grain and By-Product Handling Process Flow diagram is provided in Figure 3-2. Most of the grain received at the plant is barley but the plant also processes wheat and could process rye, rice or other grains, only in much smaller amounts. In the flow diagrams and process descriptions, whenever barley is mentioned, the description also applies to other grains.

Grain is received by truck or railcar and unloading operations occur at the truck bay (TB) and rail bay (RB). During unloading, the trucks or railcars discharge grain into hoppers, from which the grain is conveyed through the headhouse. Unloading operations result in the generation of particulate matter (PM) emissions. The truck bay receiving pit is equipped with side draw vacuums with exhaust to Baghouse 1 (BH1). Hopper-type trucks account for a majority of the truck receiving operations. These trucks and railcar unloading operations employ choke feed to the receiving pit to minimize fugitive particulate emissions.

The grain is transferred through the headhouse to the grain storage silos. PM emissions generated by headhouse transfer operations are controlled by BH1. The grain is cleaned and graded. The grain transfers and the cleaning device emissions are controlled by BH2. “Thin” grain is transferred to Feed Barley transfer bins and the material is trucked offsite for use as animal feed. Feed Barley transfer operations are controlled by BH1. Feed Barley truck loadout operations are controlled by a cyclone side vacuum draw system that exhausts to BH3.

Materials collected by all of the centralized baghouse systems (BH1, BH2 and BH3) are sent to the pellet mill (Section 2.3.4).

The project will not change the grain handling operations at the plant. Emissions from the grain handling equipment will increase as a result of the increase in grain throughput quantities.

2.3.2 Malting

Existing Malting Process

After cleaning, the grain is transferred to the malting operations. Currently there is one malting process at the plant that takes place in the Malthouse. The existing Malthouse contains steeping tanks and six germination beds. The process flow diagram for the exiting Malthouse is provided in Figure 3-3. The grain is conveyed to steep tanks where it is steeped by placing it in large tanks with cool water. Following steeping, the grain is dropped into one of 6 temperature and humidity controlled germination beds and allowed to grow.

The steeping and germination processes are served by chilled water systems. The germination beds are periodically sanitized with hypochlorite resulting in minor emissions of chlorine through the Germination Bed Exhaust emission points (GBE 1-6). The sanitizing is performed on one germination bed on any given day with emissions lasting for a period of about 2 hours. The germination process requires heated air provided by the two existing natural gas-fired hot water boilers (Malthouse Boilers 1 & 2) that exhaust to a common stack (BS1).

Following germination, “green” malt is dried in an indirect natural gas-fired malt kiln (Kiln1). The malt kiln has two levels. Green malt enters the upper deck and is dried. The green malt is then transferred to the lower deck of the kiln where it is further dried to about 4% moisture content. During a portion of the kilning, sulfur may be burned in a sulfur stove and exhausted into the kiln, primarily as sulfur dioxide. Sulfur is only burned if customer product specifications require its use. The kiln emits PM, volatile organic compounds (VOC) and sulfur dioxide that are vented through a single stack (KSE).

Currently, heat for the kiln is provided by ten natural gas-fired malt kiln burners that exhaust through 5 malt kiln burner stacks (KS1-KS5). The burners for the existing kiln will be replaced with ten air-to-air heat exchangers to provide drying air to the kiln. The new heat exchangers will have ten natural gas-fired low NOx burners, one for each heat exchanger. Each burner will have a 7.9 MM Btu/hr heat input capacity. The exhausts from the new heat exchanger burners will discharge through the 5 malt kiln burner stacks (KS1-KS5).

New Malting Process

The project will add a new malting process line to the plant. The new malting equipment will include 16 new steep tanks, 4 new germination vessels, and 1 new kiln. A detailed process flow diagram for the new malting process is provided in Figure 3-4.

There will be two new conveyor transfer points as grain is conveyed to the new steep tanks. Steep tank fill conveyor 1 (STC1) and steep tank fill conveyor 2 (STC2) will each have a new dust filter (STC1F and STC2F) to capture particulate matter from the grain transfers into the new steeps. The steep tanks will be located in a Steep House in an upper group of eight tanks (STA1-STA8) and a lower group of eight tanks (STB1-STB8). Each steep tank will have its own stack for exhausting CO2 emissions.

Heat for the Steep House building will be provided by two natural gas-fired makeup air heaters (MAU1- MAU2). Each heater will have a 2.188 MM Btu/hr heat input capacity.

Four new germination vessels (GV1- GV4) will be constructed. Each vessel will be an independent structure. There will be two stacks for each GV for a total of eight stacks (S19-S26). Just like in the existing germination equipment, the new germination vessels will be sanitized using hypochlorite, which may produce minor amounts of chlorine emissions. Only one germination vessel will be sanitized on any given day with emissions lasting up to 2 hours per cleaning event.

The hot water for germination will be provided by 6 new natural gas-fired boilers. Each boiler will have a 2 MM Btu/hr heat input capacity. Three boilers (GVB1-GVB3) will serve GV1 and GV2 but only two boilers will operate at any one time and one will serve as a backup. Similarly, three boilers (GVB4-GVB6) will serve GV3 and GV4 with only two boilers operating at any one time.

A new malt kiln (Kiln2) will be constructed in a new separate building at the plant. The new kiln will use four air-to-air heat exchangers to provide the drying air for the kiln. The heat exchangers will have a total of four natural gas-fired burners (KB1- KB4), one for each heat exchanger. Each burner will have an 18.15 MM Btu/hr heat input capacity and its own exhaust stack (S27-S30). The sulfur will not be burned in the new kiln. Air from the kiln will be discharged from a single stack (S31).

Biogenic carbon dioxide (CO2) is given off during the malting process and is generated from combustion equipment. This pollutant will need to be added to the permit for the existing and new equipment.

2.3.3 Malt Handling

After the malt is dried in the kiln, it is conveyed and placed into bins for analysis, then it is cleaned and transferred to malt storage silos until it is shipped. The process flow diagram is shown in Figure 3-5.

Two new 375 MT malt analysis bins (BA1 and BA2) will be added to handle the malt from the new kiln (K2). The malt analysis bins will have fill conveyors and dust filters (BA1F and BA2F) for capturing particulate matter when filling the bins. These bins are used as temporary storage while the malt is being analyzed for product quality.

There will be two new malt conveyer transfer points when moving the malt from the new kiln to the existing malt handling conveyors. One transfer point is called the new malt leg conveyor (NML) and the other is called New Malt Conveyor 3 (NMC3). Each conveyor transfer point will have a dust filter (NMLF and NMC3F) to control particulate emissions.

After analysis, the malt is cleaned before it is placed into storage. A new drum scalper and aspirator will be replacing some of the existing malt cleaning (MC) equipment at the plant. Particulate matter generated during cleaning is collected in existing baghouse 2

(BH2). Grain transfer emissions are collected in existing Baghouse 3 (BH3). The existing baghouses have enough capacity to control the additional throughputs.

The increase in malt production will require the addition of storage to the existing plant. The plan is to add 10 new 750 MT malt storage bins. There will be two new fill conveyors (NMSBC1 and NMSBC2), one for each group of 5 malt storage bins. The dust from the malt storage bins during filling will be captured in the enclosed conveyor and vented through a new dust filter, one filter for each conveyor (NMSBC1F and NMSBC2F).

Before shipping, the malt is transferred from the storage bins into smaller loadout bins. The project will add 4 new 40 MT Micro Bins (loadout bins). The Micro Bin fill conveyor (MBC) will have a dust filter (MBCF) for controlling dust during bin filling. The Micro Bins will be used to store specific qualities and mixes of malts for micro-brew customer orders.

The malt is shipped by railcar and truck. The malt is gravity fed into trucks in the existing Truck Bay (TB) or railcars in the existing Rail Bay (RB). There will be an increase in the number of trucks and railcars after the project starts operation as a result of the increase in production.

2.3.4 By-Product Handling

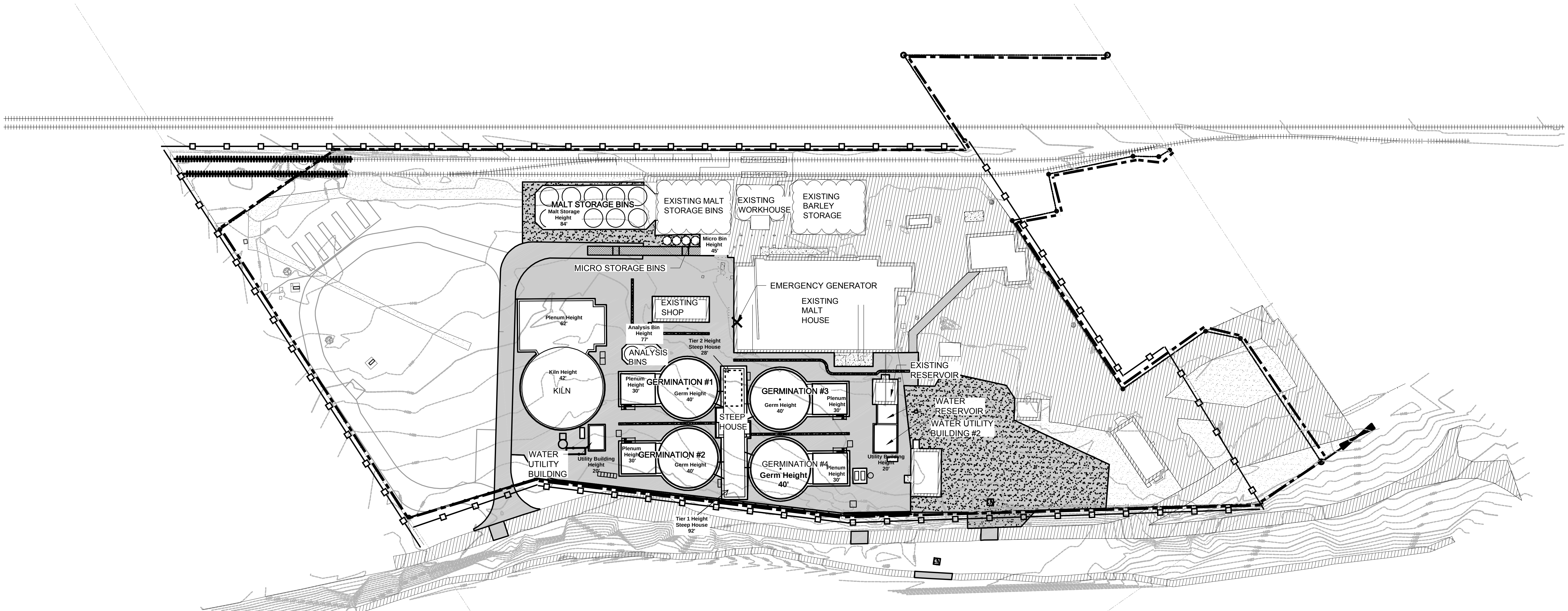
By-products are produced from the kilning process. By-products from the new kiln will be pneumatically conveyed to a new cyclone that feeds into an existing by-product storage bin. A dust filter (KBPCF) will be used to control emissions from the kiln by-product cyclone (KBPC) exhaust.

By-products from the kilns and material collected by the baghouses are sent to an existing pellet mill system where the material is pelletized and shipped offsite. The pellet mill mixer requires steam provided by an existing steam boiler (pellet mill boiler) that exhausts through its own boiler stack (BS2). After pellets are formed, they are cooled using the existing pellet mill cooler cyclone and stored in a pellet bin. The cooler cyclone exhausts directly to atmosphere through its own stack (CS). The loadout of pelletized material into trucks results in fugitive emissions. The existing pellet mill system has enough capacity to handle the grain residues, malt by-products and baghouse material from the expansion so no changes are planned to the pellet mill system or pellet mill boiler.

The process flow diagram for the by-product handling and pellet mill is included in Figure 3-2.

3.0 Site Plan and Process Flow Diagrams

This section contains the figures for site plan and process flow diagrams.



Legend

- Building Edge
- Tier Edge
- Fence Line
- Property Line

NORTH

1
EX15

EX15 - SITE PLAN EXHIBIT

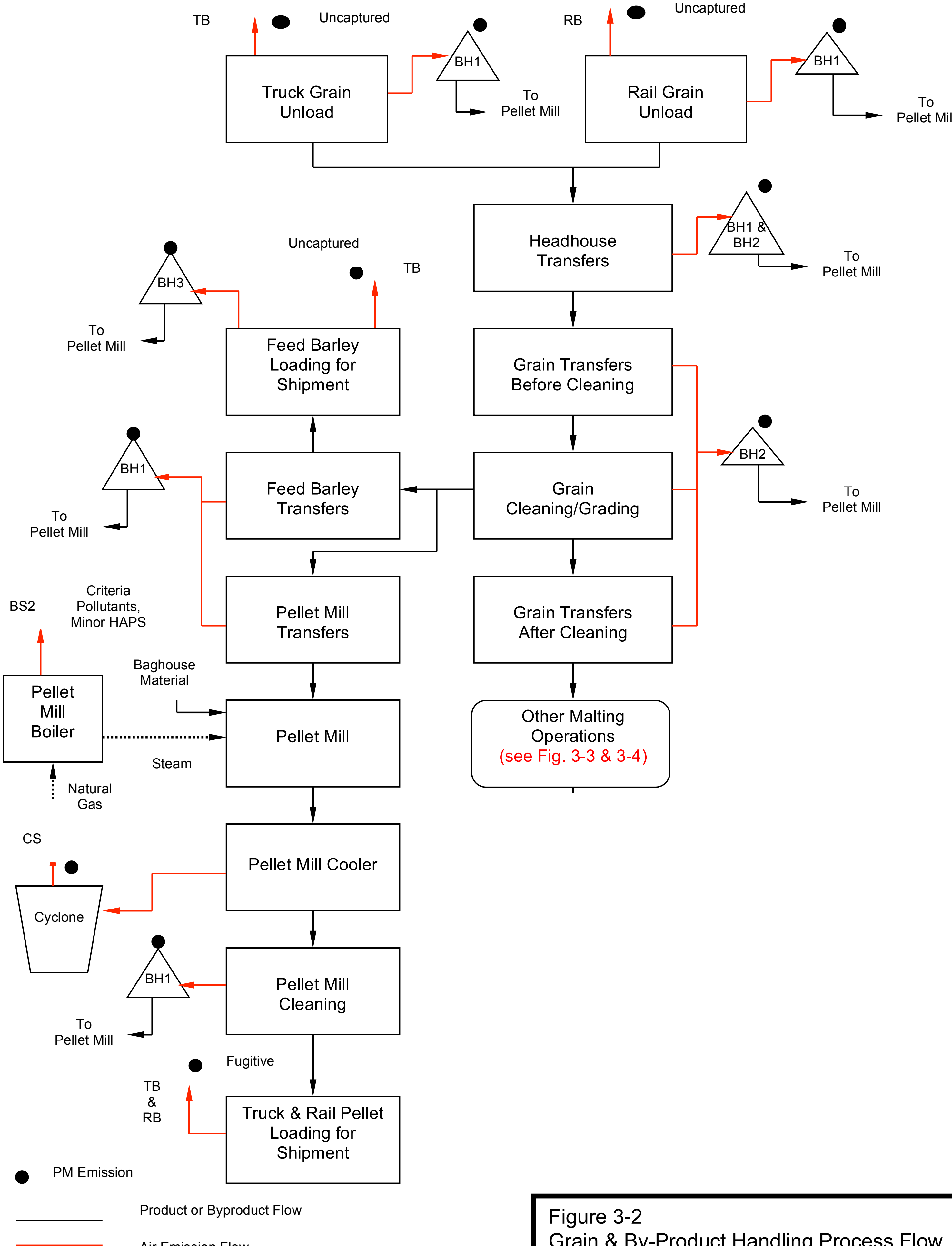
0 150' 300' 450'

1"= 150'

Figure 3-1: General Site Map

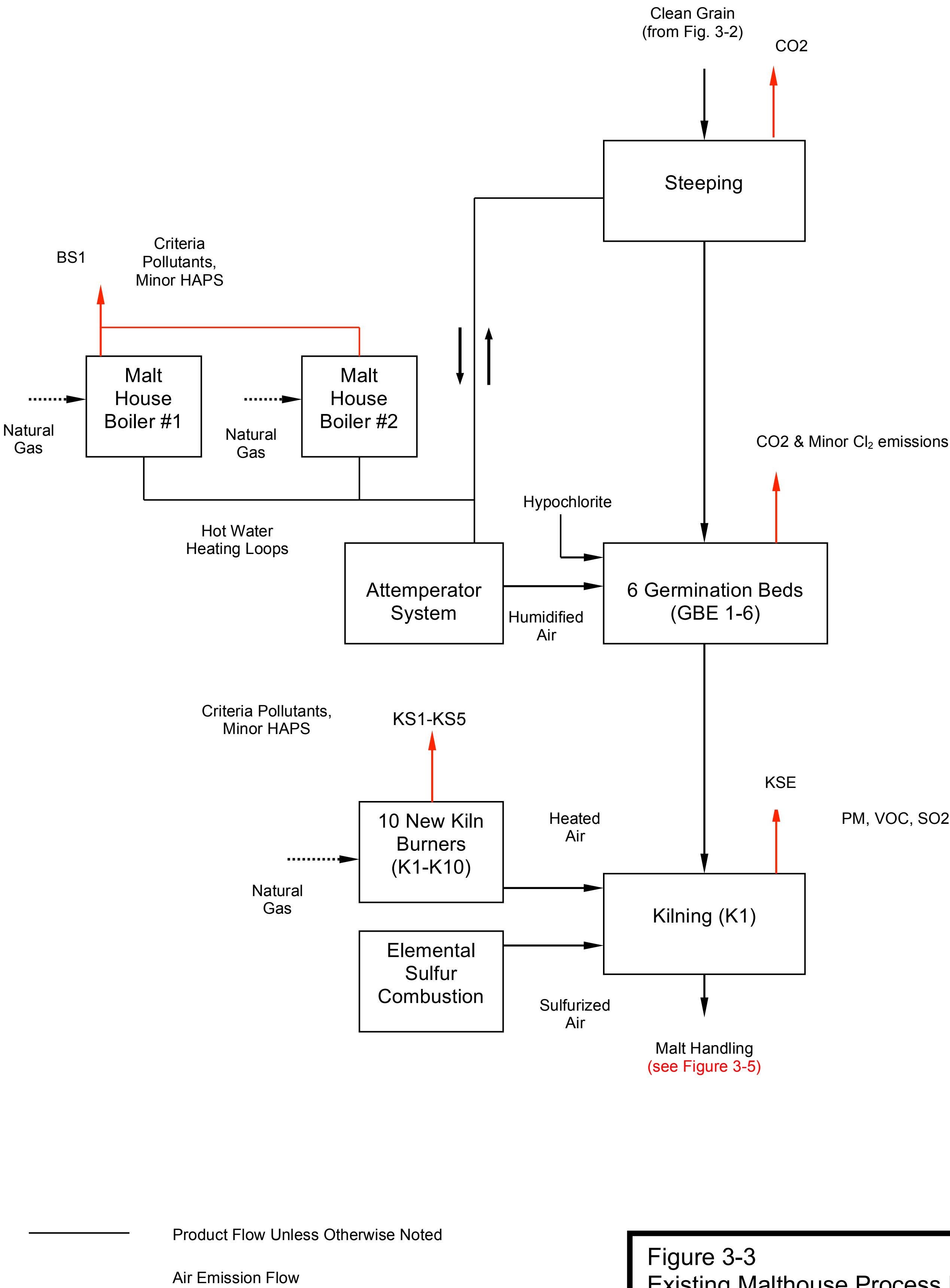
POCATELLO, ID

PROJECT: 150248
8/26/2015



RB = Rail Bay; TB = Truck Bay; BH = Baghouse; CS = Cyclone Stack; BS = Boiler Stack

Figure 3-2
Grain & By-Product Handling Process Flow



KSE = Kiln Stack Exhaust; BS1 = Boiler Stacks 1
KS1-KS5 = Kiln Burner Stacks 1-5

Figure 3-3
Existing Malthouse Process Flow

Preliminary Information- Design Subject to Change

NOTES:
1. FILLING TIME OF 8 STEEPS WITH WATER, MAX 60MIN.
2. DRAIN TIME FOR ALL 8 STEEPS TO BE <30MIN.

Figure 3-4

REV	DESCRIPTION	DRN	CKD	DATE
P2	GENERAL UPDATE BY JIM HALLETT PRIOR TO 2nd DESIGN WORKGROUP WITH JHK	GC	JH	19.06.15

Great Western Malting Co.

SCALE N.A.		PROJECT POCATELLO MALTINGS EXPANSION	PROJECT No. POC001
DRAWN G. Chahine	DATE 28.04.2015	TITLE PROCESS FLOW DIAGRAM	DRAWING STATUS DEVELOPMENT
DESIGNED JIM HALLETT	DATE 28.04.2015		DRAWING No. 00-PFD-001
CHECKED	DATE		REVISION P2
APPROVED	DATE		

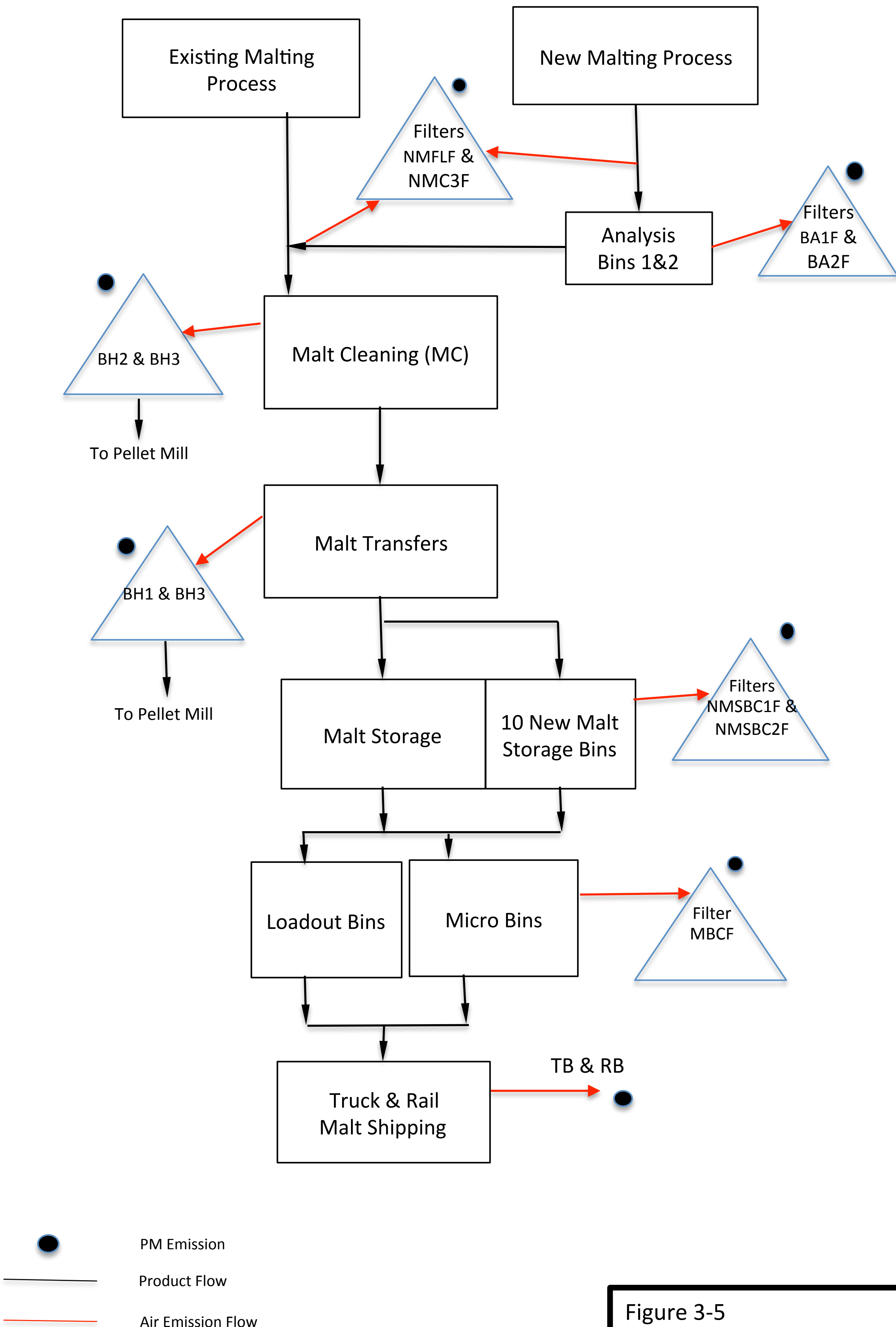


Figure 3-5
Malt Handling Process Flow

4.0 Applicable Requirements

4.1 State Regulations

This section provides a discussion of Idaho DEQ air quality regulations that may impose substantive requirements related to air releases from the new equipment in the expansion project. The air quality regulations with requirements that are more general and apply facility wide, like excess emissions reporting, payment of fees, open burning, and permitting, are not included. Regulatory requirements related to other environmental media, such as stormwater management, are not addressed in this document.

Each regulation is identified and then is followed with a discussion of how the Great Western Malting project complies with the requirements.

IDPA 58.01.01.123- Certification of Documents

The rule requires that all documents submitted to the Department, including application forms, must contain a certification by a responsible official. A Great Western Malting responsible official has reviewed the application and signed the certification statement as shown on Form GI in Section 1 of this application.

IDPA 58.01.01.210- Demonstration of Preconstruction Compliance with Toxic Standards.

The rule requires that Great Western Malting demonstrate preconstruction compliance with toxic air pollutant (TAP) requirements. Lists of emission quantities of each TAP for each emission unit with a comparison to the screening emission level (ELs) are show in Tables 4-1 and 4-2. Compliance is demonstrated if the emissions are less than the EL or if air dispersion modeling is performed to show impacts are less than acceptable ambient concentrations (AAC) or less than acceptable ambient concentrations for carcinogens (AACC).

Details of the emission calculations are discussed in Section 5 and in Appendix E to this application. Dispersion modeling results are presented in Section 7. Model results show that impacts for formaldehyde are less than the AACC and chlorine impacts are less than the AAC. Emissions of the other TAPs are all less than the EL so no further evaluation is required.

Table 4-1: TAPs Compliance Summary- Non-Carcinogens Controlled Emissions

TAP	Controlled Emissions (lb/hr)								
	Malthouse Boilers ** (BS1)	Pellet Mill Boiler (BS2)	New Kiln 1 Heaters (KS1-KS5)	New Germination Boilers (GVB1-GVB6)	New Kiln 2 Heaters (KB1-KB4)	New Makeup Air Heaters (MAU1-MAU2)	Total lb/hr	EL lb/hr	Compliance Demonstration
Acrolein*	1.69E-05	6.75E-06	2.09E-04	2.16E-05	1.91E-04	1.18E-05	0.00046	0.017	Total Below EL
Ethyl Benzene*	5.94E-05	2.38E-05	7.36E-04	7.60E-05	6.73E-04	4.16E-05	0.00161	29	Total Below EL
Hexane*	3.94E-05	1.58E-05	4.88E-04	5.04E-05	4.46E-04	2.76E-05	0.00107	12	Total Below EL
Naphthalene*	1.88E-06	7.50E-07	2.32E-05	2.40E-06	2.12E-05	1.31E-06	0.00005	3.33	Total Below EL
Toluene*	2.29E-04	9.15E-05	2.83E-03	2.93E-04	2.59E-03	1.60E-04	0.00620	25	Total Below EL
Xylenes*	1.70E-04	6.80E-05	2.11E-03	2.18E-04	1.93E-03	1.19E-04	0.00461	29	Total Below EL

* 24-hr average

** Hourly heat input restriction on Existing Malthouse Boilers

TAP	Controlled Emissions (lb/hr)				
	Germination Bed Cleaning (GBE1-GBE6)	Germination Vessel Cleaning (GV1-GV4)	Total lb/hr	EL lb/hr	Compliance Demonstration
Chlorine***	0.5375	0.5375	1.075	0.2	Modeling

*** 24-hr average lb/hr

Table 4-2: TAPs Compliance Summary- Carcinogens Controlled Emissions

TAP	Controlled Emissions (lb/hr)								
	Malthouse Boilers ** (BS1)	Pellet Mill Boiler (BS2)	New Kiln 1 Heaters** (KS1-KS5)	New Germination Boilers (GVB1-GVB6)	New Kiln 2 Heaters** (KB1-KB4)	New Makeup Air Heaters (MAU1-MAU2)	Total lb/hr	EL lb/hr	Compliance Demonstration
Acetaldehyde*	1.03E-05	1.08E-05	1.42E-04	3.44E-05	2.06E-04	1.88E-05	0.00042	0.003	Total Below EL
Benzene*	1.92E-05	2.00E-05	2.65E-04	6.40E-05	3.84E-04	3.50E-05	0.00079	0.0008	Total Below EL
Formaldehyde*	4.08E-05	4.25E-05	5.63E-04	1.36E-04	8.15E-04	7.44E-05	0.00167	0.00051	Modeling
PAHs*	9.61E-07	1.00E-06	1.32E-05	3.20E-06	1.92E-05	1.75E-06	0.000039	0.000091	Total Below EL

* Annual average lb/hr

** Annual natural gas usage restriction on Existing Malthouse Boilers, New Kiln 1 heaters, New Kiln 2 heaters

IDPA 58.01.01.576- General Provisions for Ambient Air Quality Standards

The ambient air quality standards established by regulation apply to all of the state. Idaho has adopted the National Ambient Air Quality Standards (NAAQS) by reference.

Air dispersion modeling was performed for all of the sources of PM10, PM2.5, NOx, and CO at the Pocatello facility. The modeling report and approved modeling protocol are presented in Section 7 of this application. Results from the modeling are presented in the following table and show compliance with the NAAQS.

The SO2 emission increases from the expansion project were 0.04 lb/hr and 0.15 tons/yr relative to pre-project SO2 emissions. These emission increases are less than the 0.21 lb/hr and 1.2 ton/year Modeling Level 1 Thresholds, such that a dispersion modeling analysis for SO2 was not required. Modeling for VOC and CO2e emissions was not required.

Compliance with Ambient Air Quality Standards

	Averaging	Concentration ($\mu g/m^3$)			NAAQS	Exceed
Pollutant	**Period**	**Project + Competing Sources**	**Background**	**Total**	**($\mu g/m^3$)**	**NAAQS?**
Nitrogen Dioxide (NO_2)	1-hour	109.2	60.2	169.4	188	No
	Annual	8.9	9.0	17.9	100	No
Fine Particulate Matter ($PM_{2.5}$)	24-hour	21.8	12.0	33.8	35	No
	Annual	6.2	4.3	10.5	12	No
Particulate Matter (PM_{10})	24-hour	69.2	72.0	141.2	150	No
Carbon Monoxide (CO)	1-hour	1,964.8	3,306.0	5,270.8	40,000	No
	8-hour	351.6	1,118.0	1,469.6	10,000	No

IDPA 58.01.01.577- Ambient Air Quality Standards for Fluorides

The rule establishes ambient air quality standards for fluorides. The Great Western Malting facility does not emit fluorides so a compliance demonstration for this regulation is not needed.

IDPA 58.01.01.585- Toxic Air Pollutants Non-Carcinogenic Increments

The TAP screening emission level (EL) and acceptable ambient concentrations for non-carcinogens are presented in this regulation. The AACs are expressed as 24-hr averages.

The pre-project and post project potential-to-emit emissions for non-carcinogenic TAPs are presented in the following table.

Non-Carcinogenic TAP	Pre-Project 24-hour Average Emission Rates	Post Project 24-hour Average Emission Rates	Change in 24-hour Average Emission Rates	Non-Carcinogenic Screening Level (EL)	Exceeds Screening Level?
	lb/hr	lb/hr	lb/hr	lb/hr	Y/N
Acrolein	0.00033	0.00046	0.00013	0.017	No
Ethyl Benzene	0.00115	0.00161	0.00046	29	No
Hexane	0.00077	0.00107	0.00030	12	No
Naphthalene	0.00004	0.00005	0.00001	3.33	No
Toluene	0.00445	0.00620	0.00175	25	No
Xylenes	0.00330	0.00461	0.00131	29	No
Chlorine	**0.5375**	**1.0750**	**0.538**	**0.2**	**Yes**

Emissions of each non-carcinogen are less than the EL except for chlorine. Chlorine post project emissions were modeled and the resulting impact of 114.9 μg/m^3 (24-hr average) demonstrates compliance with the AAC of 150 μg/m^3 (24-hr average). The modeling results are presented in Section 7.

IDPA 58.01.01.586- Toxic Air Pollutants Carcinogenic Increments

The TAP screening emission level (EL) and acceptable ambient concentrations for carcinogens are presented in this regulation. The AACCs are expressed as annual averages.

The pre-project and post project potential-to-emit emissions for carcinogenic TAPs are presented in the following table.

Carcinogenic TAP	Pre-Project Annual Average Emission Rates	Post Project Annual Average Emission Rates	Change in Annual Average Emission Rates	Carcinogenic Screening Level (EL)	Exceeds Screening Level?
	lb/hr	lb/hr	lb/hr	lb/hr	Y/N
Acetaldehyde	1.71E-04	4.23E-04	2.52E-04	3.0E-03	No
Benzene	3.16E-04	7.87E-04	4.71E-04	8.0E-04	No
Formaldehyde	**6.72E-04**	**1.67E-03**	**1.00E-03**	**5.1E-04**	**Yes**
PAH's (including naphthalene)	1.58E-05	3.93E-05	2.35E-05	9.1E-05	No

Each of the carcinogen emissions is less than the EL except for formaldehyde. Formaldehyde post project emissions were modeled and the resulting impact of 0.0061 μg/m^3 (annual average) demonstrates compliance with the AACC of 0.077 μg/m^3 (annual average). The modeling results are presented in Section 7.

IDPA 58.01.01.590- New Source Performance Standards NSPS

An applicability determination for potentially applicable NSPS in 40 CFR Part 60 is presented in Section 4.2 of this application. Results from the NSPS review show that none of the NSPS applies to equipment at the facility.

IDPA 58.01.01.591- National Emission Standards for Hazardous Air Pollutants (NESHAP)

This regulation states that stationary sources must comply with NESHAPs in 40 CFR Part 61 and Part 63 if they apply to the source. The Pocatello facility is a minor (area) source of HAPs and will continue to be after the expansion, as shown in the following emission table.

HAP Pollutant	After Expansion Uncontrolled PTE	After Expansion PTE	Major Source Threshold	Uncontrolled PTE Exceeds Major Source Threshold and PTE Exceeds Major Source Threshold
	T/yr	T/yr	T/yr	Y/N
Acetaldehyde	0.00401	0.00185	10	No
Acrolein	0.00252	0.00116	10	No
Benzene	0.00747	0.00345	10	No
Ethyl Benzene	0.00887	0.00409	10	No
Formaldehyde	0.01587	0.00732	10	No
Hexane	0.00588	0.00271	10	No
Naphthalene	0.00028	0.00013	10	No
PAH's (including naphthalene)	0.00037	0.00017	10	No
Toluene	0.03417	0.01576	10	No
Xylenes	0.02539	0.01171	10	No
Chlorine	1.19135	1.19135	10	No
Site Total	**1.25156**	**1.21913**	**25**	**No**

The NESHAP regulations were reviewed and the only regulation identified as applicable was 40 CFR Part 63 Subpart ZZZZ for reciprocating internal combustion engines (RICE). Details of the RICE regulation and how it applies to the emergency generator (EG) at the plant are discussed in Section 4.2 of this application.

IDPA 58.01.01.625- Visible Emissions

This regulation states that Great Western Malting shall not discharge any air pollutant into the atmosphere from any point of emission for a period or periods aggregating more than 3 minutes in a 60-minute period which is greater than 20% opacity when measured by EPA Method 9, as altered by the rule [IDPA 58.01.01.625.04].

The boilers and heaters at the Pocatello plant are all natural gas-fired. Natural gas typically burns without visible emissions. The emergency generator will be incompliance with the maintenance requirements in the RICE NESHAP and should not have visible emissions except for short periods during a cold start. Most of the grain and malt handling, processing and storage equipment have dust control filters that are designed and operated to minimize emissions. All of the sources at the plant will be in compliance with the 20% opacity limit.

To demonstrate compliance with the 20% opacity limit Great Western Malting periodically will perform monthly visible emission inspections at the plant using a see/no see evaluation. If visible emissions are observed, Great Western Malting will either take corrective action as expeditiously as possible or perform an EPA Method 9 opacity test according to rule requirements. Records of the inspections and corrective actions will be maintained at the plant.

IDPA 58.01.01.650 through 651- Rules for Control of Fugitive Dust and General Rules

All reasonable precautions must be taken to prevent particulate matter from becoming airborne. Great Western Malting will employ the following precautions on an as-needed basis:

1. Use water to control dust during construction operations, grading of roads or clearing of land.
2. Use water to suppress dust from dirt roads during construction.
3. Use baghouses and dust collectors on the grain and malt handling equipment.

   Ten new filters will be added to the new material handling and storage equipment for air pollution control including:

APCD Name	APCD ID	APCD Name	APCD ID
Steep Tank Conveyor 1 Filter	STC1F	Kiln By-Product Cyclone Filter	KBPCF
Steep Tank Conveyor 2 Filter	STC2F	New Malt Conveyor 3 Filter	NMC3F
New Malt Leg Filter	NMLF	Micro Bins Conveyor Filter	MBCF
Analysis Bin 1 Filter	BA1F	New Malt Storage Bins Conveyor 1 Filter	NMSBC1F
Analysis Bin 2 Filter	BA2F	New Malt Storage Bins Conveyor 2 Filter	NMSBC2F

4. Use paving on the roadways and work areas around the plant site.
5. Periodically remove dust and track-out on the paved traffic areas at the plant.

IDPA 58.01.01.675 through 677- Fuel Burning Equipment- Particulate Matter

These regulations establish particulate matter emission standards for fuel-burning equipment. Fuel-burning equipment is defined as *"any furnace, boiler, apparatus, stack and all appurtenances thereto, used in the process of burning fuel for the primary purpose of producing heat or power by indirect heat transfer."* [IDPA 58.01.01.005.45].

Section 676: Standards for New Sources

Particulate emissions shall be a maximum of 0.015 gr/dscf at 3% O2 from gas fired equipment greater than 10 MM Btu/hr of heat input that commenced operation after October 1, 1979. Each of the four new Kiln 2 air-to-air heat exchanger burners (KB1-KB4) will be natural gas-fired with heat input of 18.15 MM Btu/hr and will be subject to this requirement. The existing malthouse boilers (BS1) have heat inputs greater than 10 MM Btu/hr and commenced operation in 1980 so they also are subject to this particulate limit. Compliance will be demonstrated by only burning natural gas and by performing periodic visible emission observations. A demonstration of emissions compliance is shown in the table below.

Section 677: Standards for Minor and Existing Sources

Particulate emissions shall be a maximum of 0.015 gr/dscf at 3% O2 from gas fired equipment less than 10 MM Btu/hr of heat input or commenced operation before October 1, 1979. All of the remaining natural gas-fired boilers and heaters at the facility are subject to this particulate limit. Compliance will be demonstrated by only burning natural gas and by performing periodic visible emission observations. A demonstration of emissions compliance is shown in the table below.

The emergency generator at the plant does not meet the definition as 'fuel-burning equipment' so it is not subject to this rule.

Compliance with Fuel Burning Equipment Particulate Limit of 0.015 gr/dscf

Source	Stack ID	PM10 (lb/hr)	PM10 (grains/min)	Flow (scfm)	PM10 (gr/scf)
Kiln 1 Burner #1	KS1	0.0589	6.87	2025	0.0034
Kiln 1 Burner #2 -#5	KS2	0.2355	27.48	8100	0.0034
Kiln 1 Burner #6	KS3	0.0589	6.87	2025	0.0034
Kiln 1 Burner #7 - #9	KS4	0.1766	20.60	6076	0.0034
Kiln 1 Burner #10	KS5	0.0589	6.87	2025	0.0034
Malt House Boilers 1&2	BS1	0.0475	5.54	1604	0.0035
Pellet Mill Boiler	BS2	0.0190	2.22	642	0.0035
GV boiler 1 (GVB1)	S38	0.0152	1.77	510	0.0035
GV boiler 2 (GVB2)	S39	0.0152	1.77	510	0.0035
GV boiler 3 (GVB3)	S40	0.0152	1.77	510	0.0035
GV boiler 4 (GVB4)	S41	0.0152	1.77	510	0.0035
GV boiler 5 (GVB5)	S42	0.0152	1.77	510	0.0035
GV boiler 6 (GVB6)	S43	0.0152	1.77	510	0.0035
Kiln 2 Burner 1 (KB1)	S27	0.1345	15.69	4660	0.0034
Kiln 2 Burner 2 (KB2)	S28	0.1345	15.69	4660	0.0034
Kiln 2 Burner 3 (KB3)	S29	0.1345	15.69	4660	0.0034
Kiln 2 Burner 4 (KB4)	S30	0.1345	15.69	4660	0.0034
Steep Blg. Makeup Air Unit 1 (MAU1)	S44	0.0166	1.94	481	0.0040
Steep Blg. Makeup Air Unit 2 (MAU2)	S45	0.0166	1.94	481	0.0040

IDPA 58.01.01.701- Particulate Matter-New Equipment Process Weight Limitations

The rule establishes allowable particulate emissions rates for process equipment in operation on or after October 1, 1979. The allowable emission rates are based on the quantity of material that is processed per hour. Fuel burning equipment is exempt from this regulation.

The process weight limits and estimated particulate emissions for each of the regulated emission units are presented in Table 4-3 at the end of this section. As shown, the equipment at the Great Western Malting plant will be in compliance with this regulation after the expansion is complete.

IDPA 58.01.01.702- Particulate Matter-Existing Equipment Process Weight Limitations

The rule applies to equipment that was in operation prior to October 1, 1979. The Pocatello plant was constructed in 1980 so this regulation does not apply.

IDPA 58.01.01.703- Particulate Matter-Other Processes

The rule applies to equipment used to dehydrate sugar beet pulp of alfalfa. None of the equipment at the Pocatello plant falls under this category so the regulation does not apply.

IDPA 58.01.01.725- Rules for Sulfur Content of Fuels

For sources that use distillate fuel oil, the sulfur content must be 0.3% or less for Grade 1 oil and 0.5% or less for Grade 2 oil. All of the heaters and boilers at the plant burn natural gas and are not subject to this requirement. The emergency generator burns low sulfur diesel with sulfur content less than these limits.

IDPA 58.01.01.776- Rules for Control of Odors-General Rules

Section 776.01. The rule requires that no person allow or cause the emission of odorous gases, liquids or solids into the atmosphere in such quantities as to cause air pollution. Great Western Malting does not have odor complaints from its existing operations and does not expect odor complaints after the expansion.

Great Western Malting will demonstrate compliance with this regulation by responding proactively to any odor complaints received by the plant. If an odor complaint is received, the plant will collect information regarding the nature and the time and duration of the odor, investigate the potential causes, take corrective actions (if needed), and will provide a response to the person making the complaint. Records of the complaint and plant responses will be kept at the plant.

Table 4-3: Compliance with Process Weight Particulate Limitations

Process	Emission Point	Max Hourly Transfer Rate (MT/hr.)	Max Hourly Transfer Rate (lb/hr)	Allowable PM Emissions (lb/hr)	PM10 Emissions (lb/hr)	Comply with Process Weight Limit?
Truck Barley Unload	BH1	150	330,000	26.36	0.12	Yes
Rail Barley Unload	BH1	150	330,000	26.36	0.07	Yes
Barley Headhouse Transfers	BH1 & BH2	150	330,000	26.36	0.03	Yes
Barley Transfers Before Cleaning	BH2	150	330,000	26.36	0.03	Yes
Barley Transfers After Cleaning	BH2	150	330,000	26.36	0.03	Yes
Steep Tanks Fill Conveyor 1 (STC1)	S1	160	352,000	26.79	0.03	Yes
Steep Tanks Fill Conveyor 2 (STC2)	S2	160	352,000	26.79	0.03	Yes
Feed Barley Transfer to Bins	BH1	150	330,000	26.36	0.03	Yes
Feed Barley Loading for Shipment	BH3	400	880,000	33.69	0.70	Yes
Pellet Mill Transfers	BH1	5	11,000	11.27	0.0009	Yes
Truck Pellet Loading for Shipment	TB	6	13,200	11.79	0.01	Yes
Rail Pellet Loading for Shipment	RB	6	13,200	11.79	0.01	Yes
Malt Transfers	BH1 & BH3	150	330,000	26.36	0.03	Yes
Kiln 2 New Malt Leg Conveyor (NML)	S32	219	481,800	28.98	0.041	Yes
Malt Analysis Bins 1-2-fill (BA1)	S33	219	481,800	28.98	0.041	Yes
Malt Analysis Bins 1-2-reclaim (BA2)	S34	219	481,800	28.98	0.041	Yes
Kiln Byproduct Cyclone (KBPC)	S35	5	11,000	11.27	0.007	Yes
New Malt Conveyor 3 (NMC3)	S36	160	352,000	26.79	0.030	Yes
Micro Bins 1-4- fill conveyor (MBC))	S37	44	96,800	19.40	0.008	Yes
Malt Storage Bins 1-5- fill conveyor 1 (NMSBC1)	S46	160	352,000	26.79	0.030	Yes
Malt Storage Bins 6-10- fill conveyor 2 (NMSBC2)	S47	160	352,000	26.79	0.030	Yes
Rail Malt Loading for Shipment	RB	180	396,000	27.59	0.44	Yes
Truck Malt Loading for Shipment	TB	20	44,000	15.93	0.64	Yes
Malt House Kilning- Kiln 1 (K1)	KSE	16.74	36,828	15.24	1.43	Yes
Barley Cleaning	BH2	150	330,000	26.36	0.05	Yes
Malt Cleaning (MC)	BH2 & BH3	150	330,000	26.36	0.05	Yes
Pellet Mill Cleaning	BH1	5	11,000	11.27	0.00174	Yes
Pellet Mill Cooler	CS	5	11,000	11.27	0.36	Yes
Kiln 2 (K2)	S31	21	46,200	16.13	1.79	Yes

4.2 Federal Regulations

The federal air regulations reviewed for this project include the New Source Performance Standards (NSPS) in 40 C.F.R Part 60 and the National Emission Standards for Hazardous Air Pollutants (NESHAP) in 40 C.F.R Part 61 and Part 63. Great Western Malting identified the following federal regulations as potentially applicable to the equipment at the malting facility:

- NSPS Part 60 Subpart Dc- Small Industrial Steam Generating Units
- NSPS Part 60 Subpart DD- Grain Elevators
- NSPS Part 60 Subpart IIII- Compression Ignition Engines
- NESHAP Part 63 Subpart JJJJJJ- Area Source Boiler MACT
- NESHAP Part 63 Subpart ZZZZ- Reciprocating Internal Combustion Engines (RICE)

Only the RICE NESHAP was found to be applicable to the emergency generator at the plant. The other federal regulations do not apply. The applicability or non-applicability determinations are presented in this section of the application.

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AIR PERMIT APPLICATION

Revision 6
10/7/09

For each box in the table below, CTRL+click on the blue underlined text for instructions and information.

IDENTIFICATION	
1. Company Name: **Great Western Malting Company**	2. Facility Name: Great Western Malting- Pocatello Plant
3. Brief Project Description:	Exanding malting capability at the Pocatello Plant
APPLICABILITY DETERMINATION	
4. List applicable subparts of the New Source Performance Standards (NSPS) (40 CFR part 60). Examples of NSPS affected emissions units include internal combustion engines, boilers, turbines, etc. The applicant must thoroughly review the list of affected emissions units.	List of potentially applicable subpart(s): Subpart Dc- Small Boilers Subpart DD- Grain Elevators Subpart IIII- CI Engines X These NSPS do not apply.
5. List applicable subpart(s) of the National Emission Standards for Hazardous Air Pollutants (NESHAP) found in 40 CFR part 61 and 40 CFR part 63. Examples of affected emission units include solvent cleaning operations, industrial cooling towers, paint stripping and miscellaneous surface coating. EPA has a web page dedicated to NESHAP that should be useful to applicants.	List of potentially applicable subpart(s): Subpart JJJJJJ- Area Source Boiler MACT Subpart ZZZZ- RICE Subpart JJJJJJ does not apply. Subpart ZZZZ applies.
6. For each subpart identified above, conduct a complete a regulatory analysis using the instructions and referencing the example provided on the following pages. **Note** - Regulatory reviews must be submitted with sufficient detail so that DEQ can verify applicability and document in legal terms why the regulation applies. Regulatory reviews that are submitted with insufficient detail will be determined incomplete.	☒ A detailed regulatory review is provided (Follow instructions and example). ☐ DEQ has already been provided a detailed regulatory review. Give a reference to the document including the date.

IF YOU ARE UNSURE HOW TO ANSWER ANY OF THESE QUESTIONS, CALL THE AIR PERMIT HOTLINE AT 1-877-5PERMIT

It is emphasized that it is the applicant's responsibility to satisfy all technical and regulatory requirements, and that DEQ will help the applicant understand what those requirements are prior to the application being submitted but that DEQ will not perform the required technical or regulatory analysis on the applicant's behalf.

NSPS Part 60 Subpart Dc—Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

§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/h)) or less, but greater than or equal to 2.9 MW (10 MMBtu/h).

The six germination boilers (GVB1-GVB6) each have maximum heat input of 2 MM Btu/hr and do not meet the 10 MM Btu/hr applicability threshold.

The two makeup air heaters (MAU1-MAU2) each have maximum heat input of 2.19 MM Btu/hr and do not meet the 10 MM Btu/hr applicability threshold. Also, they do not meet the definition as steam generating units [40 CFR §60.41c].

The ten burners in the ten new kiln air-to-air heat exchangers (KS1-KS5) each have a maximum heat input of 7.9 MM Btu/hr and do not meet the 10 MM Btu/hr applicability threshold. Also, the heat exchangers do not meet the definition as steam generating units [40 CFR §60.41c].

The four kiln burners in the four air-to-air heat exchangers (KB1-KB4) each have a maximum heat input of 18.15 MM Btu/hr and exceed the 10 MM Btu/hr applicability threshold but are not steam generating units. See the steam generating unit definition in 40 CFR §60.41c.

There are no other combustion units included in the project that would be considered affected facilities under this regulation. NSPS Subpart Dc does not apply.

(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) Affected facilities (*i.e.* heat recovery steam generators and fuel heaters) that are associated with stationary combustion 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, fuel heaters, and other affected facilities that are capable of combusting more than or equal to 2.9 MW (10 MMBtu/h) heat input of fossil fuel but less than or equal to 29 MW (100 MMBtu/h) heat input of fossil fuel. If the heat recovery steam generator, fuel heater, or other affected facility is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The stationary combustion turbine emissions are subject to subpart GG or KKKK, as applicable, of this part.)

(f) Any affected facility that meets the applicability requirements of and is subject to subpart AAAA or subpart CCCC of this part is not subject to this subpart.

(g) Any facility that meets the applicability requirements and is subject to an EPA approved State or Federal section 111(d)/129 plan implementing subpart BBBB of this part is not subject to this subpart.

(h) Affected facilities that also meet the applicability requirements under subpart J or subpart Ja of this part are subject to the PM and NO_x standards under this subpart and the SO_2 standards under subpart J or subpart Ja of this part, as applicable.

(i) Temporary boilers are not subject to this subpart.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5090, Jan. 28, 2009; 77 FR 9461, Feb. 16, 2012]

§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.

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), 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), kerosine, as defined by the American Society of

Testing and Materials in ASTM D3699 (incorporated by reference, see §60.17), biodiesel as defined by the American Society of Testing and Materials in ASTM D6751 (incorporated by reference, see §60.17), or biodiesel blends as defined by the American Society of Testing and Materials in ASTM D7467 (incorporated by reference, see §60.17).

Dry flue gas desulfurization technology means a SO_2 control 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.

The four kiln burners (KB1-KB4) are part of the four air-to-air heaters that will be used in the new kiln. The heaters heat air. The heaters do not produce steam or heat hot water or hot oil or other heat transfer medium. The kiln burners do not meet the definition of a steam generating unit as an affected facility under this NSPS. The NSPS does not apply.

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.

Temporary boiler means a steam generating unit that combusts natural gas or distillate oil with a potential SO_2emissions rate no greater than 26 ng/J (0.060 lb/MMBtu), and the unit is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A steam generating unit is not a temporary boiler if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The steam generating unit or a replacement remains at a location for more than 180 consecutive days. Any temporary boiler that replaces a temporary boiler at a location and performs the same or similar function will be included in calculating the consecutive time period.

(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.

(4) The equipment is moved from one location to another in an attempt to circumvent the residence time requirements of this definition.

Wet flue gas desulfurization technology means an SO_2 control 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.

§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_2 in 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_2 in 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_2 in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO_2 emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2 in 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_2 in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 20 percent (0.20) of the potential SO_2 emission rate (80 percent reduction); nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of SO_2 in 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_2 emissions limit or the 90 percent SO_2 reduction 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_2 emissions shall neither:

(i) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of 50 percent (0.50) of the potential SO_2 emission rate (50 percent reduction); nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in 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_2 in 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/h) 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; or

(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_2 in excess of 215 ng/J (0.50 lb/MMBtu) heat input from oil; 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/h); 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), (3), or (4) 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 affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/h).

(4) Other fuels-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/h).

(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; 77 FR 9462, Feb. 16, 2012]

§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/h) 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/h) 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 combusts coal, wood, or oil and has a heat input capacity of 8.7 MW (30 MMBtu/h) 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 (c).

(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/h) 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/h) 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) 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; 77 FR 9462, Feb. 16, 2012]

§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_2emission 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 $\%R_g$ ($\%R_go$) 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:

$$\%R_go = 100\left(1 - \frac{E^o_{ao}}{E^o_{ai}}\right)$$

Where:

$\%R_go$ = 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) As of January 1, 2012, and within 90 days after the date of completing each performance test, as defined in §60.8, conducted to demonstrate compliance with this subpart, you must submit relative accuracy test audit (*i.e.,* reference method) data and performance test (*i.e.,* compliance test) data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/ert tool.html/*) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

(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/h).

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009; 76 FR 3523, Jan. 20, 2011; 77 FR 9463, Feb. 16, 2012]

§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_2 emission limits under §60.42c shall install, calibrate, maintain, and operate a CEMS for measuring SO_2concentrations and either O_2 or CO_2 concentrations at the outlet of the SO_2 control device (or the outlet of the steam generating unit if no SO_2 control 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_2 concentrations and either O_2 or CO_2 concentrations at both the inlet and outlet of the SO_2 control device.

(b) The 1-hour average SO_2 emission 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_2CEMS 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_2control 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), and (f) 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 within 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 or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(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 or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(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 within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later; 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 10 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) An owner or operator of an affected facility that is subject to an opacity standard in §60.43c(c) is not required to operate a COMS provided that the affected facility meets the conditions in either paragraphs (f)(1), (2), or (3) of this section.

(1) The affected facility uses a fabric filter (baghouse) as the primary PM control device and, the owner or operator operates a bag leak detection system to monitor the performance of the fabric filter according to the requirements in section §60.48Da of this part.

(2) The affected facility uses an ESP as the primary PM control device, and the owner or operator uses an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the requirements in section §60.48Da of this part.

(3) The affected facility burns only gaseous fuels and/or fuel oils that contain no greater than 0.5 weight percent sulfur, and the owner or operator operates the unit according to a written site-specific monitoring plan approved by the permitting authority. 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. For testing performed as part of this site-specific monitoring plan, the permitting authority may require as an alternative to the notification and reporting requirements specified in §§60.8 and 60.11 that the owner or operator submit any deviations with the excess emissions report required under §60.48c(c).

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009; 76 FR 3523, Jan. 20, 2011; 77 FR 9463, Feb. 16, 2012]

§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_2 emissions. 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_2 emission 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_2 standard, 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_2 standard, 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]

NSPS Part 60 Subpart DD—Standards of Performance for Grain Elevators

§60.300 Applicability and designation of affected facility.

(a) The provisions of this subpart apply to each affected facility at any grain terminal elevator or any grain storage elevator, except as provided under §60.304(b). The affected facilities are each truck unloading station, truck loading station, barge and ship unloading station, barge and ship loading station, railcar loading station, railcar unloading station, grain dryer, and all grain handling operations.

The grain elevator at the Pocatello malting plant is not a 'grain terminal elevator' or a 'grain storage elevator' and therefore, this NSPS does not apply to the plant. Further explanation is provided under the definitions below.

(b) Any facility under paragraph (a) of this section which commences construction, modification, or reconstruction after August 3, 1978, is subject to the requirements of this part.

[43 FR 34347, Aug. 3, 1978, as amended at 52 FR 42434, Nov. 5, 1988]

§60.301 Definitions.

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

(a) *Grain* means corn, wheat, sorghum, rice, rye, oats, barley, and soybeans.

(b) *Grain elevator* means any plant or installation at which grain is unloaded, handled, cleaned, dried, stored, or loaded.

The Great Western Malting plant in Pocatello does have a grain elevator, but it is not a 'grain terminal elevator' and is not a 'grain storage elevator' as defined by this rule.

(c) *Grain terminal elevator* means any grain elevator which has a permanent storage capacity of more than 88,100 m^3(ca. 2.5 million U.S. bushels), except those located at animal food manufacturers, pet food manufacturers, cereal manufacturers, breweries, and livestock feedlots.

The maximum permanent grain storage capacity at the Pocatello plant after the expansion will be 17,652 m3 of grain. The maximum malt storage capacity will be 47,540 m3 of malt. The maximum grain storage is well below the 88,100 m3 applicability threshold in the 'grain terminal elevator' definition. Even the combined grain and malt storage is less that the applicability threshold. The grain elevator at the malt plant is not a 'grain terminal elevator' and is not regulated under this rule.

(d) *Permanent storage capacity* means grain storage capacity which is inside a building, bin, or silo.

(e) *Railcar* means railroad hopper car or boxcar.

(f) *Grain storage elevator* means any grain elevator located at any wheat flour mill, wet corn mill, dry corn mill (human consumption), rice mill, or soybean oil extraction plant which has a permanent grain storage capacity of 35,200 m^3 (ca. 1 million bushels).

The Great Western Malting plant in Pocatello is not a wheat flour mill, a wet corn mill, dry corn mill, rice mill or soybean extraction plant, therefore, it does not meet this definition. The grain elevator at the malt plant is not a 'grain storage elevator' regulated under this rule.

(g) *Process emission* means the particulate matter which is collected by a capture system.

(h) *Fugitive emission* means the particulate matter which is not collected by a capture system and is released directly into the atmosphere from an affected facility at a grain elevator.

(i) *Capture system* means the equipment such as sheds, hoods, ducts, fans, dampers, etc. used to collect particulate matter generated by an affected facility at a grain elevator.

(j) *Grain unloading station* means that portion of a grain elevator where the grain is transferred from a truck, railcar, barge, or ship to a receiving hopper.

(k) *Grain loading station* means that portion of a grain elevator where the grain is transferred from the elevator to a truck, railcar, barge, or ship.

(l) *Grain handling operations* include bucket elevators or legs (excluding legs used to unload barges or ships), scale hoppers and surge bins (garners), turn heads, scalpers, cleaners, trippers, and the headhouse and other such structures.

(m) *Column dryer* means any equipment used to reduce the moisture content of grain in which the grain flows from the top to the bottom in one or more continuous packed columns between two perforated metal sheets.

(n) *Rack dryer* means any equipment used to reduce the moisture content of grain in which the grain flows from the top to the bottom in a cascading flow around rows of baffles (racks).

(o) *Unloading leg* means a device which includes a bucket-type elevator which is used to remove grain from a barge or ship.

[43 FR 34347, Aug. 3, 1978, as amended at 65 FR 61759, Oct. 17, 2000]

§60.302 Standard for particulate matter.

(a) On and after the 60th day of achieving the maximum production rate at which the affected facility will be operated, but no later than 180 days after initial startup, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere any gases which exhibit greater than 0 percent opacity from any:

(1) Column dryer with column plate perforation exceeding 2.4 mm diameter (ca. 0.094 inch).

(2) Rack dryer in which exhaust gases pass through a screen filter coarser than 50 mesh.

(b) On and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility except a grain dryer any process emission which:

(1) Contains particulate matter in excess of 0.023 g/dscm (ca. 0.01 gr/dscf).

(2) Exhibits greater than 0 percent opacity.

(c) On and after the 60th day of achieving the maximum production rate at which the affected facility will be operated, but no later than 180 days after initial startup, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere any fugitive emission from:

(1) Any individual truck unloading station, railcar unloading station, or railcar loading station, which exhibits greater than 5 percent opacity.

(2) Any grain handling operation which exhibits greater than 0 percent opacity.

(3) Any truck loading station which exhibits greater than 10 percent opacity.

(4) Any barge or ship loading station which exhibits greater than 20 percent opacity.

(d) The owner or operator of any barge or ship unloading station shall operate as follows:

(1) The unloading leg shall be enclosed from the top (including the receiving hopper) to the center line of the bottom pulley and ventilation to a control device shall be maintained on both sides of the leg and the grain receiving hopper.

(2) The total rate of air ventilated shall be at least 32.1 actual cubic meters per cubic meter of grain handling capacity (ca. 40 ft^3/bu).

(3) Rather than meet the requirements of paragraphs (d)(1) and (2) of this section the owner or operator may use other methods of emission control if it is demonstrated to the Administrator's satisfaction that they would reduce emissions of particulate matter to the same level or less.

§60.303 Test methods and procedures.

(a) In conducting the performance tests required in §60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in §60.8(b). Acceptable alternative methods and procedures are given in paragraph (c) of this section.

(b) The owner or operator shall determine compliance with the particulate matter standards in §60.302 as follows:

(1) Method 5 shall be used to determine the particulate matter concentration and the volumetric flow rate of the effluent gas. The sampling time and sample volume for each run shall be at least 60 minutes and 1.70 dscm (60 dscf). The probe and filter holder shall be operated without heaters.

(2) Method 2 shall be used to determine the ventilation volumetric flow rate.

(3) Method 9 and the procedures in §60.11 shall be used to determine opacity.

(c) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:

(1) For Method 5, Method 17 may be used.

[54 FR 6674, Feb. 14, 1989]

§60.304 Modifications.

(a) The factor 6.5 shall be used in place of "annual asset guidelines repair allowance percentage," to determine whether a capital expenditure as defined by §60.2 has been made to an existing facility.

(b) The following physical changes or changes in the method of operation shall not by themselves be considered a modification of any existing facility:

(1) The addition of gravity loadout spouts to existing grain storage or grain transfer bins.

(2) The installation of automatic grain weighing scales.

(3) Replacement of motor and drive units driving existing grain handling equipment.

(4) The installation of permanent storage capacity with no increase in hourly grain handling capacity.

NSPS Part 60 Subpart IIII—Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

§60.4200 Am I subject to this subpart?

(a) The provisions of this subpart are applicable to manufacturers, owners, and operators of stationary compression ignition (CI) internal combustion engines (ICE) and other persons as specified in paragraphs (a)(1) through (4) of this section. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator.

Great Western Malting owns and operates a diesel-fired emergency generator engine (CI ICE) at the Pocatello plant.

(1) Manufacturers of stationary CI ICE with a displacement of less than 30 liters per cylinder where the model year is:

(i) 2007 or later, for engines that are not fire pump engines;

(ii) The model year listed in Table 3 to this subpart or later model year, for fire pump engines.

(2) Owners and operators of stationary CI ICE that commence construction after July 11, 2005, where the stationary CI ICE are:

(i) Manufactured after April 1, 2006, and are not fire pump engines, or

(ii) Manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

(3) Owners and operators of any stationary CI ICE that are modified or reconstructed after July 11, 2005 and any person that modifies or reconstructs any stationary CI ICE after July 11, 2005.

The diesel-fired emergency generator has not being modified or reconstructed since it was installed in 1980 and will not be modified or reconstructed as part of the expansion project; therefore, this NSPS does not apply.

(4) The provisions of §60.4208 of this subpart are applicable to all owners and operators of stationary CI ICE that commence construction after July 11, 2005.

The diesel-fired emergency generator was constructed and installed at the plant in 1980; therefore, this NSPS does not apply.

(b) The provisions of this subpart are not applicable to stationary CI ICE being tested at a stationary CI ICE test cell/stand.

(c) If you are an owner or operator of an area source subject to this subpart, you are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart applicable to area sources.

(d) Stationary CI ICE may be eligible for exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C (or the exemptions described in 40 CFR part 89, subpart J and 40

CFR part 94, subpart J, for engines that would need to be certified to standards in those parts), except that owners and operators, as well as manufacturers, may be eligible to request an exemption for national security.

(e) Owners and operators of facilities with CI ICE that are acting as temporary replacement units and that are located at a stationary source for less than 1 year and that have been properly certified as meeting the standards that would be applicable to such engine under the appropriate nonroad engine provisions, are not required to meet any other provisions under this subpart with regard to such engines.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37967, June 28, 2011]

EMISSION STANDARDS FOR MANUFACTURERS

§60.4201 What emission standards must I meet for non-emergency engines if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later non-emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 kilowatt (KW) (3,000 horsepower (HP)) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 89.112, 40 CFR 89.113, 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable, for all pollutants, for the same model year and maximum engine power.

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 through 2010 model year non-emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder to the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.

(c) Stationary CI internal combustion engine manufacturers must certify their 2011 model year and later non-emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable, for all pollutants, for the same maximum engine power.

(d) Stationary CI internal combustion engine manufacturers must certify the following non-emergency stationary CI ICE to the certification emission standards for new marine CI engines in 40 CFR 94.8, as applicable, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2007 model year through 2012 non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder;

(2) Their 2013 model year non-emergency stationary CI ICE with a maximum engine power greater than or equal to 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

(3) Their 2013 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(e) Stationary CI internal combustion engine manufacturers must certify the following non-emergency stationary CI ICE to the certification emission standards and other requirements for new marine CI engines in 40 CFR 1042.101, 40 CFR 1042.107, 40 CFR 1042.110, 40 CFR 1042.115, 40 CFR 1042.120, and 40 CFR 1042.145, as applicable, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2013 model year non-emergency stationary CI ICE with a maximum engine power less than 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

(2) Their 2014 model year and later non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder.

(f) Notwithstanding the requirements in paragraphs (a) through (c) of this section, stationary non-emergency CI ICE identified in paragraphs (a) and (c) may be certified to the provisions of 40 CFR part 94 or, if Table 1 to 40 CFR 1042.1 identifies 40 CFR part 1042 as being applicable, 40 CFR part 1042, if the engines will be used solely in either or both of the following locations:

(1) Areas of Alaska not accessible by the Federal Aid Highway System (FAHS); and

(2) Marine offshore installations.

(g) Notwithstanding the requirements in paragraphs (a) through (f) of this section, stationary CI internal combustion engine manufacturers are not required to certify reconstructed engines; however manufacturers may elect to do so. The reconstructed engine must be certified to the emission standards specified in paragraphs (a) through (e) of this section that are applicable to the model year, maximum engine power, and displacement of the reconstructed stationary CI ICE.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37967, June 28, 2011]

§60.4202 What emission standards must I meet for emergency engines if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (a)(1) through (2) of this section.

(1) For engines with a maximum engine power less than 37 KW (50 HP):

(i) The certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants for model year 2007 engines, and

(ii) The certification emission standards for new nonroad CI engines in 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, 40 CFR 1039.115, and table 2 to this subpart, for 2008 model year and later engines.

(2) For engines with a maximum engine power greater than or equal to 37 KW (50 HP), the certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants beginning in model year 2007.

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (b)(1) through (2) of this section.

(1) For 2007 through 2010 model years, the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.

(2) For 2011 model year and later, the certification emission standards for new nonroad CI engines for engines of the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants.

(c) [Reserved]

(d) Beginning with the model years in table 3 to this subpart, stationary CI internal combustion engine manufacturers must certify their fire pump stationary CI ICE to the emission standards in table 4 to this subpart, for all pollutants, for the same model year and NFPA nameplate power.

(e) Stationary CI internal combustion engine manufacturers must certify the following emergency stationary CI ICE that are not fire pump engines to the certification emission standards for new marine CI engines in 40 CFR 94.8, as applicable, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2007 model year through 2012 emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder;

(2) Their 2013 model year and later emergency stationary CI ICE with a maximum engine power greater than or equal to 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder;

(3) Their 2013 model year emergency stationary CI ICE with a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder; and

(4) Their 2014 model year and later emergency stationary CI ICE with a maximum engine power greater than or equal to 2,000 KW (2,682 HP) and a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(f) Stationary CI internal combustion engine manufacturers must certify the following emergency stationary CI ICE to the certification emission standards and other requirements applicable to Tier 3 new marine CI engines in 40 CFR 1042.101, 40 CFR 1042.107, 40 CFR 1042.115, 40 CFR 1042.120, and 40 CFR 1042.145, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2013 model year and later emergency stationary CI ICE with a maximum engine power less than 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

(2) Their 2014 model year and later emergency stationary CI ICE with a maximum engine power less than 2,000 KW (2,682 HP) and a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(g) Notwithstanding the requirements in paragraphs (a) through (d) of this section, stationary emergency CI internal combustion engines identified in paragraphs (a) and (c) may be certified to the provisions of 40 CFR part 94 or, if Table 2 to 40 CFR 1042.101 identifies Tier 3 standards as being applicable, the requirements applicable to Tier 3 engines in 40 CFR part 1042, if the engines will be used solely in either or both of the following locations:

(1) Areas of Alaska not accessible by the FAHS; and

(2) Marine offshore installations.

(h) Notwithstanding the requirements in paragraphs (a) through (f) of this section, stationary CI internal combustion engine manufacturers are not required to certify reconstructed engines; however manufacturers may elect to do so. The reconstructed engine must be certified to the emission standards specified in paragraphs (a) through (f) of this section that are applicable to the model year, maximum engine power and displacement of the reconstructed emergency stationary CI ICE.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37968, June 28, 2011]

§60.4203 How long must my engines meet the emission standards if I am a manufacturer of stationary CI internal combustion engines?

Engines manufactured by stationary CI internal combustion engine manufacturers must meet the emission standards as required in §§60.4201 and 60.4202 during the certified emissions life of the engines.

[76 FR 37968, June 28, 2011]

EMISSION STANDARDS FOR OWNERS AND OPERATORS

§60.4204 What emission standards must I meet for non-emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of less than 10 liters per cylinder must comply with the emission standards in table 1 to this subpart. Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder must comply with the emission standards in 40 CFR 94.8(a)(1).

(b) Owners and operators of 2007 model year and later non-emergency stationary CI ICE with a displacement of less than 30 liters per cylinder must comply with the emission standards for new CI engines in §60.4201 for their 2007 model year and later stationary CI ICE, as applicable.

(c) Owners and operators of non-emergency stationary CI engines with a displacement of greater than or equal to 30 liters per cylinder must meet the following requirements:

(1) For engines installed prior to January 1, 2012, limit the emissions of NO_x in the stationary CI internal combustion engine exhaust to the following:

(i) 17.0 grams per kilowatt-hour (g/KW-hr) (12.7 grams per horsepower-hr (g/HP-hr)) when maximum engine speed is less than 130 revolutions per minute (rpm);

(ii) $45 \cdot n^{-0.2}$ g/KW-hr ($34 \cdot n^{-0.2}$ g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and

(iii) 9.8 g/KW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012 and before January 1, 2016, limit the emissions of NO_x in the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $44 \cdot n^{-0.23}$ g/KW-hr ($33 \cdot n^{-0.23}$ g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) For engines installed on or after January 1, 2016, limit the emissions of NO_x in the stationary CI internal combustion engine exhaust to the following:

(i) 3.4 g/KW-hr (2.5 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $9.0 \cdot n^{-0.20}$ g/KW-hr ($6.7 \cdot n^{-0.20}$ g/HP-hr) where n (maximum engine speed) is 130 or more but less than 2,000 rpm; and

(iii) 2.0 g/KW-hr (1.5 g/HP-hr) where maximum engine speed is greater than or equal to 2,000 rpm.

(4) Reduce particulate matter (PM) emissions by 60 percent or more, or limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.15 g/KW-hr (0.11 g/HP-hr).

(d) Owners and operators of non-emergency stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests in-use must meet the not-to-exceed (NTE) standards as indicated in §60.4212.

(e) Owners and operators of any modified or reconstructed non-emergency stationary CI ICE subject to this subpart must meet the emission standards applicable to the model year, maximum engine power, and displacement of the modified or reconstructed non-emergency stationary CI ICE that are specified in paragraphs (a) through (d) of this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37968, June 28, 2011]

§60.4205 What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of pre-2007 model year emergency stationary CI ICE with a displacement of less than 10 liters per cylinder that are not fire pump engines must comply with the emission standards in Table 1 to this subpart. Owners and operators of pre-2007 model year emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards in 40 CFR 94.8(a)(1).

(b) Owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards for new nonroad CI engines in §60.4202, for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE.

(c) Owners and operators of fire pump engines with a displacement of less than 30 liters per cylinder must comply with the emission standards in table 4 to this subpart, for all pollutants.

(d) Owners and operators of emergency stationary CI engines with a displacement of greater than or equal to 30 liters per cylinder must meet the requirements in this section.

(1) For engines installed prior to January 1, 2012, limit the emissions of NO_x in the stationary CI internal combustion engine exhaust to the following:

(i) 17.0 g/KW-hr (12.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $45 \cdot n^{-0.2}$ g/KW-hr ($34 \cdot n^{-0.2}$ g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and

(iii) 9.8 g/kW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012, limit the emissions of NO_x in the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $44 \cdot n^{-0.23}$ g/KW-hr ($33 \cdot n^{-0.23}$ g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) Limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.40 g/KW-hr (0.30 g/HP-hr).

(e) Owners and operators of emergency stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests in-use must meet the NTE standards as indicated in §60.4212.

(f) Owners and operators of any modified or reconstructed emergency stationary CI ICE subject to this subpart must meet the emission standards applicable to the model year, maximum engine power, and displacement of the modified or reconstructed CI ICE that are specified in paragraphs (a) through (e) of this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

§60.4206 How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?

Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in §§60.4204 and 60.4205 over the entire life of the engine.

[76 FR 37969, June 28, 2011]

Fuel Requirements for Owners and Operators

§60.4207 What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?

(a) Beginning October 1, 2007, owners and operators of stationary CI ICE subject to this subpart that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(a).

(b) Beginning October 1, 2010, owners and operators of stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to October 1, 2010, may be used until depleted.

(c) [Reserved]

(d) Beginning June 1, 2012, owners and operators of stationary CI ICE subject to this subpart with a displacement of greater than or equal to 30 liters per cylinder are no longer subject to the requirements of paragraph (a) of this section, and must use fuel that meets a maximum per-gallon sulfur content of 1,000 parts per million (ppm).

(e) Stationary CI ICE that have a national security exemption under §60.4200(d) are also exempt from the fuel requirements in this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011; 78 FR 6695, Jan. 30, 2013]

OTHER REQUIREMENTS FOR OWNERS AND OPERATORS

§60.4208 What is the deadline for importing or installing stationary CI ICE produced in previous model years?

(a) After December 31, 2008, owners and operators may not install stationary CI ICE (excluding fire pump engines) that do not meet the applicable requirements for 2007 model year engines.

(b) After December 31, 2009, owners and operators may not install stationary CI ICE with a maximum engine power of less than 19 KW (25 HP) (excluding fire pump engines) that do not meet the applicable requirements for 2008 model year engines.

(c) After December 31, 2014, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 19 KW (25 HP) and less than 56 KW (75 HP) that do not meet the applicable requirements for 2013 model year non-emergency engines.

(d) After December 31, 2013, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 56 KW (75 HP) and less than 130 KW (175 HP) that do not meet the applicable requirements for 2012 model year non-emergency engines.

(e) After December 31, 2012, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 130 KW (175 HP), including those above 560 KW (750 HP), that do not meet the applicable requirements for 2011 model year non-emergency engines.

(f) After December 31, 2016, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 560 KW (750 HP) that do not meet the applicable requirements for 2015 model year non-emergency engines.

(g) After December 31, 2018, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power greater than or equal to 600 KW (804 HP) and less than 2,000 KW (2,680 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that do not meet the applicable requirements for 2017 model year non-emergency engines.

(h) In addition to the requirements specified in §§60.4201, 60.4202, 60.4204, and 60.4205, it is prohibited to import stationary CI ICE with a displacement of less than 30 liters per cylinder that do not meet the applicable requirements specified in paragraphs (a) through (g) of this section after the dates specified in paragraphs (a) through (g) of this section.

(i) The requirements of this section do not apply to owners or operators of stationary CI ICE that have been modified, reconstructed, and do not apply to engines that were removed from one existing location and reinstalled at a new location.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

§60.4209 What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?

If you are an owner or operator, you must meet the monitoring requirements of this section. In addition, you must also meet the monitoring requirements specified in §60.4211.

(a) If you are an owner or operator of an emergency stationary CI internal combustion engine that does not meet the standards applicable to non-emergency engines, you must install a non-resettable hour meter prior to startup of the engine.

(b) If you are an owner or operator of a stationary CI internal combustion engine equipped with a diesel particulate filter to comply with the emission standards in §60.4204, the diesel particulate filter must be installed with a backpressure monitor that notifies the owner or operator when the high backpressure limit of the engine is approached.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

COMPLIANCE REQUIREMENTS

§60.4210 What are my compliance requirements if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of less than 10 liters per cylinder to the emission standards specified in §60.4201(a) through (c) and §60.4202(a), (b) and (d) using the certification procedures required in 40 CFR part 89, subpart B, or 40 CFR part 1039, subpart C, as applicable, and must test their engines as specified in those parts. For the purposes of this subpart, engines certified to the standards in table 1 to this subpart shall be subject to the same requirements as engines certified to the standards in 40 CFR part 89. For the purposes of this subpart, engines certified to the standards in table 4 to this subpart shall be subject to the same requirements as engines certified to the standards in 40 CFR part 89, except that engines with NFPA nameplate power of less than 37 KW (50 HP) certified to model year 2011 or later standards shall be subject to the same requirements as engines certified to the standards in 40 CFR part 1039.

(b) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder to the emission standards specified in §60.4201(d) and (e) and §60.4202(e) and (f) using the certification procedures required in 40 CFR part 94, subpart C, or 40 CFR part 1042, subpart C, as applicable, and must test their engines as specified in 40 CFR part 94 or 1042, as applicable.

(c) Stationary CI internal combustion engine manufacturers must meet the requirements of 40 CFR 1039.120, 1039.125, 1039.130, and 1039.135, and 40 CFR part 1068 for engines that are certified to the emission standards in 40 CFR part 1039. Stationary CI internal combustion engine manufacturers must meet the corresponding provisions of 40 CFR part 89, 40 CFR part 94 or 40 CFR part 1042 for engines that would be covered by that part if they were nonroad (including marine) engines. Labels on such engines must refer to stationary engines, rather than or in addition to nonroad or marine engines, as appropriate. Stationary CI internal combustion engine manufacturers must label their engines according to paragraphs (c)(1) through (3) of this section.

(1) Stationary CI internal combustion engines manufactured from January 1, 2006 to March 31, 2006 (January 1, 2006 to June 30, 2006 for fire pump engines), other than those that are part of certified engine families under the nonroad CI engine regulations, must be labeled according to 40 CFR 1039.20.

(2) Stationary CI internal combustion engines manufactured from April 1, 2006 to December 31, 2006 (or, for fire pump engines, July 1, 2006 to December 31 of the year preceding the year listed in table 3 to this subpart) must be labeled according to paragraphs (c)(2)(i) through (iii) of this section:

(i) Stationary CI internal combustion engines that are part of certified engine families under the nonroad regulations must meet the labeling requirements for nonroad CI engines, but do not have to meet the labeling requirements in 40 CFR 1039.20.

(ii) Stationary CI internal combustion engines that meet Tier 1 requirements (or requirements for fire pumps) under this subpart, but do not meet the requirements applicable to nonroad CI engines must be labeled according to 40 CFR 1039.20. The engine manufacturer may add language to the label clarifying that the engine meets Tier 1 requirements (or requirements for fire pumps) of this subpart.

(iii) Stationary CI internal combustion engines manufactured after April 1, 2006 that do not meet Tier 1 requirements of this subpart, or fire pumps engines manufactured after July 1, 2006 that do not meet the requirements for fire pumps under this subpart, may not be used in the U.S. If any such engines are manufactured in the U.S. after April 1, 2006 (July 1, 2006 for fire pump engines), they must be exported or must be brought into compliance with the appropriate standards prior to initial operation. The export provisions of 40 CFR 1068.230 would apply to engines for export and the manufacturers must label such engines according to 40 CFR 1068.230.

(3) Stationary CI internal combustion engines manufactured after January 1, 2007 (for fire pump engines, after January 1 of the year listed in table 3 to this subpart, as applicable) must be labeled according to paragraphs (c)(3)(i) through (iii) of this section.

(i) Stationary CI internal combustion engines that meet the requirements of this subpart and the corresponding requirements for nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in 40 CFR parts 89, 94, 1039 or 1042, as appropriate.

(ii) Stationary CI internal combustion engines that meet the requirements of this subpart, but are not certified to the standards applicable to nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in 40 CFR parts 89, 94, 1039 or 1042, as appropriate, but the words “stationary” must be included instead of “nonroad” or “marine” on the label. In addition, such engines must be labeled according to 40 CFR 1039.20.

(iii) Stationary CI internal combustion engines that do not meet the requirements of this subpart must be labeled according to 40 CFR 1068.230 and must be exported under the provisions of 40 CFR 1068.230.

(d) An engine manufacturer certifying an engine family or families to standards under this subpart that are identical to standards applicable under 40 CFR parts 89, 94, 1039 or 1042 for that model year may certify any such family that contains both nonroad (including marine) and stationary engines as a single engine family and/or may include any such family containing stationary engines in the averaging, banking and trading provisions applicable for such engines under those parts.

(e) Manufacturers of engine families discussed in paragraph (d) of this section may meet the labeling requirements referred to in paragraph (c) of this section for stationary CI ICE by either adding a separate label containing the information required in paragraph (c) of this section or by adding the words “and stationary” after the word “nonroad” or “marine,” as appropriate, to the label.

(f) Starting with the model years shown in table 5 to this subpart, stationary CI internal combustion engine manufacturers must add a permanent label stating that the engine is for stationary emergency use only to each new emergency stationary CI internal combustion engine greater than or equal to 19 KW (25 HP) that meets all the emission standards for emergency engines in §60.4202 but does not meet all the emission standards for non-emergency engines in §60.4201. The label must be added according to the labeling requirements specified in 40 CFR 1039.135(b). Engine manufacturers must specify in the owner's manual that operation of emergency engines is limited to emergency operations and required maintenance and testing.

(g) Manufacturers of fire pump engines may use the test cycle in table 6 to this subpart for testing fire pump engines and may test at the NFPA certified nameplate HP, provided that the engine is labeled as "Fire Pump Applications Only".

(h) Engine manufacturers, including importers, may introduce into commerce uncertified engines or engines certified to earlier standards that were manufactured before the new or changed standards took effect until inventories are depleted, as long as such engines are part of normal inventory. For example, if the engine manufacturers' normal industry practice is to keep on hand a one-month supply of engines based on its projected sales, and a new tier of standards starts to apply for the 2009 model year, the engine manufacturer may manufacture engines based on the normal inventory requirements late in the 2008 model year, and sell those engines for installation. The engine manufacturer may not circumvent the provisions of §60.4201 or §60.4202 by stockpiling engines that are built before new or changed standards take effect. Stockpiling of such engines beyond normal industry practice is a violation of this subpart.

(i) The replacement engine provisions of 40 CFR 89.1003(b)(7), 40 CFR 94.1103(b)(3), 40 CFR 94.1103(b)(4) and 40 CFR 1068.240 are applicable to stationary CI engines replacing existing equipment that is less than 15 years old.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

§60.4211 What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) If you are an owner or operator and must comply with the emission standards specified in this subpart, you must do all of the following, except as permitted under paragraph (g) of this section:

(1) Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions;

(2) Change only those emission-related settings that are permitted by the manufacturer; and

(3) Meet the requirements of 40 CFR parts 89, 94 and/or 1068, as they apply to you.

(b) If you are an owner or operator of a pre-2007 model year stationary CI internal combustion engine and must comply with the emission standards specified in §§60.4204(a) or 60.4205(a), or if you are an owner or operator of a CI fire pump engine that is manufactured prior to the model years in table 3 to this subpart and must comply with the emission standards specified in §60.4205(c), you must demonstrate compliance according to one of the methods specified in paragraphs (b)(1) through (5) of this section.

(1) Purchasing an engine certified according to 40 CFR part 89 or 40 CFR part 94, as applicable, for the same model year and maximum engine power. The engine must be installed and configured according to the manufacturer's specifications.

(2) Keeping records of performance test results for each pollutant for a test conducted on a similar engine. The test must have been conducted using the same methods specified in this subpart and these methods must have been followed correctly.

(3) Keeping records of engine manufacturer data indicating compliance with the standards.

(4) Keeping records of control device vendor data indicating compliance with the standards.

(5) Conducting an initial performance test to demonstrate compliance with the emission standards according to the requirements specified in §60.4212, as applicable.

(c) If you are an owner or operator of a 2007 model year and later stationary CI internal combustion engine and must comply with the emission standards specified in §60.4204(b) or §60.4205(b), or if you are an owner or operator of a CI fire pump engine that is manufactured during or after the model year that applies to your fire pump engine power rating in table 3 to this subpart and must comply with the emission standards specified in §60.4205(c), you must comply by purchasing an engine certified to the emission standards in §60.4204(b), or §60.4205(b) or (c), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in paragraph (g) of this section.

(d) If you are an owner or operator and must comply with the emission standards specified in §60.4204(c) or §60.4205(d), you must demonstrate compliance according to the requirements specified in paragraphs (d)(1) through (3) of this section.

(1) Conducting an initial performance test to demonstrate initial compliance with the emission standards as specified in §60.4213.

(2) Establishing operating parameters to be monitored continuously to ensure the stationary internal combustion engine continues to meet the emission standards. The owner or operator must petition the Administrator for approval of operating parameters to be monitored continuously. The petition must include the information described in paragraphs (d)(2)(i) through (v) of this section.

(i) Identification of the specific parameters you propose to monitor continuously;

(ii) A discussion of the relationship between these parameters and NO_x and PM emissions, identifying how the emissions of these pollutants change with changes in these parameters, and how limitations on these parameters will serve to limit NO_x and PM emissions;

(iii) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(iv) A discussion identifying the methods and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(v) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(3) For non-emergency engines with a displacement of greater than or equal to 30 liters per cylinder, conducting annual performance tests to demonstrate continuous compliance with the emission standards as specified in §60.4213.

(e) If you are an owner or operator of a modified or reconstructed stationary CI internal combustion engine and must comply with the emission standards specified in §60.4204(e) or §60.4205(f), you must demonstrate compliance according to one of the methods specified in paragraphs (e)(1) or (2) of this section.

(1) Purchasing, or otherwise owning or operating, an engine certified to the emission standards in §60.4204(e) or §60.4205(f), as applicable.

(2) Conducting a performance test to demonstrate initial compliance with the emission standards according to the requirements specified in §60.4212 or §60.4213, as appropriate. The test must be conducted within 60 days after the engine commences operation after the modification or reconstruction.

(f) If you own or operate an emergency stationary ICE, you must operate the emergency stationary ICE according to the requirements in paragraphs (f)(1) through (3) of this section. In order for the engine to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (3) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (3) of this section, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary ICE in emergency situations.

(2) You may operate your emergency stationary ICE for any combination of the purposes specified in paragraphs (f)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (f)(3) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.

(ii) Emergency stationary ICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see §60.17), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.

(iii) Emergency stationary ICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

(3) Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. Except as provided in paragraph (f)(3)(i) of this section, the 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator;

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

(ii) [Reserved]

(g) If you do not install, configure, operate, and maintain your engine and control device according to the manufacturer's emission-related written instructions, or you change emission-related settings in a way that is not permitted by the manufacturer, you must demonstrate compliance as follows:

(1) If you are an owner or operator of a stationary CI internal combustion engine with maximum engine power less than 100 HP, you must keep a maintenance plan and records of conducted maintenance to demonstrate compliance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, if you do not install and configure the engine and control device according to the manufacturer's emission-related written instructions, or you change the emission-related settings in a way that is not permitted by the manufacturer, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of such action.

(2) If you are an owner or operator of a stationary CI internal combustion engine greater than or equal to 100 HP and less than or equal to 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer.

(3) If you are an owner or operator of a stationary CI internal combustion engine greater than 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer. You must conduct subsequent performance testing every 8,760 hours of engine operation or 3 years, whichever comes first, thereafter to demonstrate compliance with the applicable emission standards.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37970, June 28, 2011; 78 FR 6695, Jan. 30, 2013]

TESTING REQUIREMENTS FOR OWNERS AND OPERATORS

§60.4212 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of less than 30 liters per cylinder?

Owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests pursuant to this subpart must do so according to paragraphs (a) through (e) of this section.

(a) The performance test must be conducted according to the in-use testing procedures in 40 CFR part 1039, subpart F, for stationary CI ICE with a displacement of less than 10 liters per cylinder, and according to 40 CFR part 1042, subpart F, for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder.

(b) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1039 must not exceed the not-to-exceed (NTE) standards for the same model year and maximum engine power as required in 40 CFR 1039.101(e) and 40 CFR 1039.102(g)(1), except as specified in 40 CFR 1039.104(d). This requirement starts when NTE requirements take effect for nonroad diesel engines under 40 CFR part 1039.

(c) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8, as applicable, must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in 40 CFR 89.112 or 40 CFR 94.8, as applicable, determined from the following equation:

$$\text{NTE requirement for each pollutant} = (1.25) \times (\text{STD}) \qquad \text{(Eq. 1)}$$

Where:

STD = The standard specified for that pollutant in 40 CFR 89.112 or 40 CFR 94.8, as applicable.

Alternatively, stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8 may follow the testing procedures specified in §60.4213 of this subpart, as appropriate.

(d) Exhaust emissions from stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in §60.4204(a), §60.4205(a), or §60.4205(c) must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in §60.4204(a), §60.4205(a), or §60.4205(c), determined from the equation in paragraph (c) of this section.

Where:

STD = The standard specified for that pollutant in §60.4204(a), §60.4205(a), or §60.4205(c).

Alternatively, stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in §60.4204(a), §60.4205(a), or §60.4205(c) may follow the testing procedures specified in §60.4213, as appropriate.

(e) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1042 must not exceed the NTE standards for the same model year and maximum engine power as required in 40 CFR 1042.101(c).

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011]

§60.4213 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of greater than or equal to 30 liters per cylinder?

Owners and operators of stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder must conduct performance tests according to paragraphs (a) through (f) of this section.

(a) Each performance test must be conducted according to the requirements in §60.8 and under the specific conditions that this subpart specifies in table 7. The test must be conducted within 10 percent of 100 percent peak (or the highest achievable) load.

(b) You may not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in §60.8(c).

(c) You must conduct three separate test runs for each performance test required in this section, as specified in §60.8(f). Each test run must last at least 1 hour.

(d) To determine compliance with the percent reduction requirement, you must follow the requirements as specified in paragraphs (d)(1) through (3) of this section.

(1) You must use Equation 2 of this section to determine compliance with the percent reduction requirement:

$$\frac{C_i - C_o}{C_i} \times 100 = R \qquad \text{(Eq. 2)}$$

Where:

C_i = concentration of NO_X or PM at the control device inlet,

C_o = concentration of NO_X or PM at the control device outlet, and

R = percent reduction of NO_x or PM emissions.

(2) You must normalize the NO_x or PM concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen (O_2) using Equation 3 of this section, or an equivalent percent carbon dioxide (CO_2) using the procedures described in paragraph (d)(3) of this section.

$$C_{adj} = C_d \frac{5.9}{20.9 - \%\, O_2} \qquad \text{(Eq. 3)}$$

Where:

C_{adj} = Calculated NO_X or PM concentration adjusted to 15 percent O_2.

C_d = Measured concentration of NO_X or PM, uncorrected.

5.9 = 20.9 percent O_2–15 percent O_2, the defined O_2 correction value, percent.

$\%O_2$ = Measured O_2 concentration, dry basis, percent.

(3) If pollutant concentrations are to be corrected to 15 percent O_2 and CO_2 concentration is measured in lieu of O_2concentration measurement, a CO_2 correction factor is needed. Calculate the CO_2 correction factor as described in paragraphs (d)(3)(i) through (iii) of this section.

(i) Calculate the fuel-specific F_o value for the fuel burned during the test using values obtained from Method 19, Section 5.2, and the following equation:

$$F_o = \frac{0.209 F_d}{F_c} \qquad \text{(Eq. 4)}$$

Where:

F_o = Fuel factor based on the ratio of O_2 volume to the ultimate CO_2 volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is O_2, percent/100.

F_d = Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm^3/J ($dscf/10^6$ Btu).

F_c = Ratio of the volume of CO_2 produced to the gross calorific value of the fuel from Method 19, dsm^3/J ($dscf/10^6$ Btu).

(ii) Calculate the CO_2 correction factor for correcting measurement data to 15 percent O_2, as follows:

$$X_{CO_2} = \frac{5.9}{F_o} \qquad \text{(Eq. 5)}$$

Where:

X_{CO2} = CO_2 correction factor, percent.

5.9 = 20.9 percent O_2–15 percent O_2, the defined O_2 correction value, percent.

(iii) Calculate the NO_x and PM gas concentrations adjusted to 15 percent O_2 using CO_2 as follows:

$$C_{adj} = C_d \frac{X_{CO_2}}{\%CO_2} \qquad \text{(Eq. 6)}$$

Where:

C_{adj} = Calculated NO_x or PM concentration adjusted to 15 percent O_2.

C_d = Measured concentration of NO_x or PM, uncorrected.

$\%CO_2$ = Measured CO_2 concentration, dry basis, percent.

(e) To determine compliance with the NO_x mass per unit output emission limitation, convert the concentration of NO_xin the engine exhaust using Equation 7 of this section:

$$ER = \frac{C_d \times 1.912 \times 10^{-3} \times Q \times T}{\text{KW-hour}} \qquad \text{(Eq. 7)}$$

Where:

ER = Emission rate in grams per KW-hour.

C_d = Measured NO_x concentration in ppm.

1.912×10^{-3} = Conversion constant for ppm NO_x to grams per standard cubic meter at 25 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour.

T = Time of test run, in hours.

KW-hour = Brake work of the engine, in KW-hour.

(f) To determine compliance with the PM mass per unit output emission limitation, convert the concentration of PM in the engine exhaust using Equation 8 of this section:

$$ER = \frac{C_{adj} \times Q \times T}{\text{KW-hour}} \qquad \text{(Eq. 8)}$$

Where:

ER = Emission rate in grams per KW-hour.

C_{adj} = Calculated PM concentration in grams per standard cubic meter.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour.

T = Time of test run, in hours.

KW-hour = Energy output of the engine, in KW.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011]

NOTIFICATION, REPORTS, AND RECORDS FOR OWNERS AND OPERATORS

§60.4214 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of non-emergency stationary CI ICE that are greater than 2,237 KW (3,000 HP), or have a displacement of greater than or equal to 10 liters per cylinder, or are pre-2007 model year engines that are greater than 130 KW (175 HP) and not certified, must meet the requirements of paragraphs (a)(1) and (2) of this section.

(1) Submit an initial notification as required in §60.7(a)(1). The notification must include the information in paragraphs (a)(1)(i) through (v) of this section.

(i) Name and address of the owner or operator;

(ii) The address of the affected source;

(iii) Engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement;

(iv) Emission control equipment; and

(v) Fuel used.

(2) Keep records of the information in paragraphs (a)(2)(i) through (iv) of this section.

(i) All notifications submitted to comply with this subpart and all documentation supporting any notification.

(ii) Maintenance conducted on the engine.

(iii) If the stationary CI internal combustion is a certified engine, documentation from the manufacturer that the engine is certified to meet the emission standards.

(iv) If the stationary CI internal combustion is not a certified engine, documentation that the engine meets the emission standards.

(b) If the stationary CI internal combustion engine is an emergency stationary internal combustion engine, the owner or operator is not required to submit an initial notification. Starting with the model years in table 5 to this subpart, if the emergency engine does not meet the standards applicable to non-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.

(c) If the stationary CI internal combustion engine is equipped with a diesel particulate filter, the owner or operator must keep records of any corrective action taken after the backpressure monitor has notified the owner or operator that the high backpressure limit of the engine is approached.

(d) If you own or operate an emergency stationary CI ICE with a maximum engine power more than 100 HP that operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §60.4211(f)(2)(ii) and (iii) or that operates for the purposes specified in §60.4211(f)(3)(i), you must submit an annual report according to the requirements in paragraphs (d)(1) through (3) of this section.

(1) The report must contain the following information:

(i) Company name and address where the engine is located.

(ii) Date of the report and beginning and ending dates of the reporting period.

(iii) Engine site rating and model year.

(iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(v) Hours operated for the purposes specified in §60.4211(f)(2)(ii) and (iii), including the date, start time, and end time for engine operation for the purposes specified in §60.4211(f)(2)(ii) and (iii).

(vi) Number of hours the engine is contractually obligated to be available for the purposes specified in §60.4211(f)(2)(ii) and (iii).

(vii) Hours spent for operation for the purposes specified in §60.4211(f)(3)(i), including the date, start time, and end time for engine operation for the purposes specified in §60.4211(f)(3)(i). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

(2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

(3) The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in §60.4.

[71 FR 39172, July 11, 2006, as amended at 78 FR 6696, Jan. 30, 2013]

SPECIAL REQUIREMENTS

§60.4215 What requirements must I meet for engines used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands?

(a) Stationary CI ICE with a displacement of less than 30 liters per cylinder that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are required to meet the applicable emission standards in §§60.4202 and 60.4205.

(b) Stationary CI ICE that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are not required to meet the fuel requirements in §60.4207.

(c) Stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are required to meet the following emission standards:

(1) For engines installed prior to January 1, 2012, limit the emissions of NO_x in the stationary CI internal combustion engine exhaust to the following:

(i) 17.0 g/KW-hr (12.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $45 \cdot n^{-0.2}$ g/KW-hr ($34 \cdot n^{-0.2}$ g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and

(iii) 9.8 g/KW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012, limit the emissions of NO_x in the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) 44 · $n^{-0.23}$ g/KW-hr (33 · $n^{-0.23}$ g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) Limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.40 g/KW-hr (0.30 g/HP-hr).

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011]

§60.4216 What requirements must I meet for engines used in Alaska?

(a) Prior to December 1, 2010, owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder located in areas of Alaska not accessible by the FAHS should refer to 40 CFR part 69 to determine the diesel fuel requirements applicable to such engines.

(b) Except as indicated in paragraph (c) of this section, manufacturers, owners and operators of stationary CI ICE with a displacement of less than 10 liters per cylinder located in areas of Alaska not accessible by the FAHS may meet the requirements of this subpart by manufacturing and installing engines meeting the requirements of 40 CFR parts 94 or 1042, as appropriate, rather than the otherwise applicable requirements of 40 CFR parts 89 and 1039, as indicated in sections §§60.4201(f) and 60.4202(g) of this subpart.

(c) Manufacturers, owners and operators of stationary CI ICE that are located in areas of Alaska not accessible by the FAHS may choose to meet the applicable emission standards for emergency engines in §§60.4202 and 60.4205, and not those for non-emergency engines in §60.4201 and §60.4204, except that for 2014 model year and later non-emergency CI ICE, the owner or operator of any such engine that was not certified as meeting Tier 4 PM standards, must meet the applicable requirements for PM in §§60.4201 and 60.4204 or install a PM emission control device that achieves PM emission reductions of 85 percent, or 60 percent for engines with a displacement of greater than or equal to 30 liters per cylinder, compared to engine-out emissions.

(d) The provisions of §60.4207 do not apply to owners and operators of pre-2014 model year stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the FAHS.

(e) The provisions of §60.4208(a) do not apply to owners and operators of stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the FAHS until after December 31, 2009.

(f) The provisions of this section and §60.4207 do not prevent owners and operators of stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the FAHS from using fuels mixed with used lubricating oil, in volumes of up to 1.75 percent of the total fuel. The sulfur content of the used lubricating oil must be less than 200 parts per million. The used lubricating oil must meet the on-specification levels and properties for used oil in 40 CFR 279.11.

[76 FR 37971, June 28, 2011]

§60.4217 What emission standards must I meet if I am an owner or operator of a stationary internal combustion engine using special fuels?

Owners and operators of stationary CI ICE that do not use diesel fuel may petition the Administrator for approval of alternative emission standards, if they can demonstrate that they use a fuel that is not the fuel on which the manufacturer of the engine certified the engine and that the engine cannot meet the applicable standards required in §60.4204 or §60.4205 using such fuels and that use of such fuel is appropriate and reasonably necessary, considering cost, energy, technical feasibility, human health and environmental, and other factors, for the operation of the engine.

[76 FR 37972, June 28, 2011]

General Provisions

§60.4218 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§60.1 through 60.19 apply to you.

Definitions

§60.4219 What definitions apply to this subpart?

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

Certified emissions life means the period during which the engine is designed to properly function in terms of reliability and fuel consumption, without being remanufactured, specified as a number of hours of operation or calendar years, whichever comes first. The values for certified emissions life for stationary CI ICE with a displacement of less than 10 liters per cylinder are given in 40 CFR 1039.101(g). The values for certified emissions life for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder are given in 40 CFR 94.9(a).

Combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle combustion turbine, any regenerative/recuperative cycle combustion turbine, the combustion turbine portion of any cogeneration cycle combustion system, or the combustion turbine portion of any combined cycle steam/electric generating system.

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Date of manufacture means one of the following things:

(1) For freshly manufactured engines and modified engines, date of manufacture means the date the engine is originally produced.

(2) For reconstructed engines, date of manufacture means the date the engine was originally produced, except as specified in paragraph (3) of this definition.

(3) Reconstructed engines are assigned a new date of manufacture if the fixed capital cost of the new and refurbished components exceeds 75 percent of the fixed capital cost of a comparable entirely new facility. An engine that is produced from a previously used engine block does not retain the date of manufacture of the engine in which the engine block was previously used if the engine is produced using all new components except for the engine block. In these cases, the date of manufacture is the date of reconstruction or the date the new engine is produced.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is number 2 distillate oil.

Diesel particulate filter means an emission control technology that reduces PM emissions by trapping the particles in a flow filter substrate and periodically removes the collected particles by either physical action or by oxidizing (burning off) the particles in a process called regeneration.

Emergency stationary internal combustion engine means any stationary reciprocating internal combustion engine that meets all of the criteria in paragraphs (1) through (3) of this definition. All emergency stationary ICE must comply with the requirements specified in §60.4211(f) in order to be considered emergency stationary ICE. If the engine does not comply with the requirements specified in §60.4211(f), then it is not considered to be an emergency stationary ICE under this subpart.

(1) The stationary ICE is operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary ICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary ICE used to pump water in the case of fire or flood, etc.

(2) The stationary ICE is operated under limited circumstances for situations not included in paragraph (1) of this definition, as specified in §60.4211(f).

(3) The stationary ICE operates as part of a financial arrangement with another entity in situations not included in paragraph (1) of this definition only as allowed in §60.4211(f)(2)(ii) or (iii) and §60.4211(f)(3)(i).

Engine manufacturer means the manufacturer of the engine. See the definition of “manufacturer” in this section.

Fire pump engine means an emergency stationary internal combustion engine certified to NFPA requirements that is used to provide power to pump water for fire suppression or protection.

Freshly manufactured engine means an engine that has not been placed into service. An engine becomes freshly manufactured when it is originally produced.

Installed means the engine is placed and secured at the location where it is intended to be operated.

Manufacturer has the meaning given in section 216(1) of the Act. In general, this term includes any person who manufactures a stationary engine for sale in the United States or otherwise introduces a new stationary engine into commerce in the United States. This includes importers who import stationary engines for sale or resale.

Maximum engine power means maximum engine power as defined in 40 CFR 1039.801.

Model year means the calendar year in which an engine is manufactured (see “date of manufacture”), except as follows:

(1) Model year means the annual new model production period of the engine manufacturer in which an engine is manufactured (see “date of manufacture”), if the annual new model production period is different than the calendar year and includes January 1 of the calendar year for which the model year is named. It may not begin before January 2 of the previous calendar year and it must end by December 31 of the named calendar year.

(2) For an engine that is converted to a stationary engine after being placed into service as a nonroad or other non-stationary engine, model year means the calendar year or new model production period in which the engine was manufactured (see “date of manufacture”).

Other internal combustion engine means any internal combustion engine, except combustion turbines, which is not a reciprocating internal combustion engine or rotary internal combustion engine.

Reciprocating internal combustion engine means any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work.

Rotary internal combustion engine means any internal combustion engine which uses rotary motion to convert heat energy into mechanical work.

Spark ignition means relating to a gasoline, natural gas, or liquefied petroleum gas fueled engine or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

Stationary internal combustion engine means any internal combustion engine, except combustion turbines, that converts heat energy into mechanical work and is not mobile. Stationary ICE differ from mobile ICE in that a stationary internal combustion engine is not a nonroad engine as defined at 40 CFR 1068.30 (excluding paragraph (2)(ii) of that definition), and is not used to propel a motor vehicle, aircraft, or a vehicle used solely for competition. Stationary ICE include reciprocating ICE, rotary ICE, and other ICE, except combustion turbines.

Subpart means 40 CFR part 60, subpart IIII.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37972, June 28, 2011; 78 FR 6696, Jan. 30, 2013]

Table 1 to Subpart IIII of Part 60—Emission Standards for Stationary Pre-2007 Model Year Engines With a Displacement of <10 Liters per Cylinder and 2007-2010 Model Year Engines >2,237 KW (3,000 HP) and With a Displacement of <10 Liters per Cylinder

[As stated in §§60.4201(b), 60.4202(b), 60.4204(a), and 60.4205(a), you must comply with the following emission standards]

Maximum engine power	Emission standards for stationary pre-2007 model year engines with a displacement of <10 liters per cylinder and 2007-2010 model year engines >2,237 KW (3,000 HP) and with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)				
	NMHC + NO_x	HC	NO_x	CO	PM
KW<8 (HP<11)	10.5 (7.8)			8.0 (6.0)	1.0 (0.75)
8≤KW<19 (11≤HP<25)	9.5 (7.1)			6.6 (4.9)	0.80 (0.60)
19≤KW<37 (25≤HP<50)	9.5 (7.1)			5.5 (4.1)	0.80 (0.60)

37≤KW<56 (50≤HP<75)			9.2 (6.9)		
56≤KW<75 (75≤HP<100)			9.2 (6.9)		
75≤KW<130 (100≤HP<175)			9.2 (6.9)		
130≤KW<225 (175≤HP<300)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
225≤KW<450 (300≤HP<600)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
450≤KW≤560 (600≤HP≤750)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
KW>560 (HP>750)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)

Table 2 to Subpart IIII of Part 60—Emission Standards for 2008 Model Year and Later Emergency Stationary CI ICE <37 KW (50 HP) With a Displacement of <10 Liters per Cylinder

[As stated in §60.4202(a)(1), you must comply with the following emission standards]

Engine power	Emission standards for 2008 model year and later emergency stationary CI ICE <37 KW (50 HP) with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)			
	Model year(s)	**NO_x + NMHC**	**CO**	**PM**
KW<8 (HP<11)	2008+	7.5 (5.6)	8.0 (6.0)	0.40 (0.30)
8≤KW<19 (11≤HP<25)	2008+	7.5 (5.6)	6.6 (4.9)	0.40 (0.30)
19≤KW<37 (25≤HP<50)	2008+	7.5 (5.6)	5.5 (4.1)	0.30 (0.22)

Table 3 to Subpart IIII of Part 60—Certification Requirements for Stationary Fire Pump Engines

As stated in §60.4202(d), you must certify new stationary fire pump engines beginning with the following model years:

Engine power	Starting model year engine manufacturers must certify new stationary fire pump engines according to §60.4202(d)[1]
KW<75 (HP<100)	2011
75≤KW<130	2010

(100≤HP<175)	
130≤KW≤560 (175≤HP≤750)	2009
KW>560 (HP>750)	2008

[1]Manufacturers of fire pump stationary CI ICE with a maximum engine power greater than or equal to 37 kW (50 HP) and less than 450 KW (600 HP) and a rated speed of greater than 2,650 revolutions per minute (rpm) are not required to certify such engines until three model years following the model year indicated in this Table 3 for engines in the applicable engine power category.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37972, June 28, 2011]

Table 4 to Subpart IIII of Part 60—Emission Standards for Stationary Fire Pump Engines

[As stated in §§60.4202(d) and 60.4205(c), you must comply with the following emission standards for stationary fire pump engines]

Maximum engine power	Model year(s)	NMHC + NO_x	CO	PM
KW<8 (HP<11)	2010 and earlier	10.5 (7.8)	8.0 (6.0)	1.0 (0.75)
	2011+	7.5 (5.6)		0.40 (0.30)
8≤KW<19 (11≤HP<25)	2010 and earlier	9.5 (7.1)	6.6 (4.9)	0.80 (0.60)
	2011+	7.5 (5.6)		0.40 (0.30)
19≤KW<37 (25≤HP<50)	2010 and earlier	9.5 (7.1)	5.5 (4.1)	0.80 (0.60)
	2011+	7.5 (5.6)		0.30 (0.22)
37≤KW<56 (50≤HP<75)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2011+[1]	4.7 (3.5)		0.40 (0.30)
56≤KW<75 (75≤HP<100)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2011+[1]	4.7 (3.5)		0.40 (0.30)
75≤KW<130 (100≤HP<175)	2009 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2010+[2]	4.0 (3.0)		0.30 (0.22)
130≤KW<225 (175≤HP<300)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+[3]	4.0 (3.0)		0.20 (0.15)
225≤KW<450 (300≤HP<600)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+[3]	4.0 (3.0)		0.20 (0.15)
450≤KW≤560 (600≤HP≤750)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+	4.0 (3.0)		0.20 (0.15)
KW>560 (HP>750)	2007 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)

	2008+	6.4 (4.8)		0.20 (0.15)

[1]For model years 2011-2013, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 revolutions per minute (rpm) may comply with the emission limitations for 2010 model year engines.

[2]For model years 2010-2012, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2009 model year engines.

[3]In model years 2009-2011, manufacturers of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2008 model year engines.

Table 5 to Subpart IIII of Part 60—Labeling and Recordkeeping Requirements for New Stationary Emergency Engines

[You must comply with the labeling requirements in §60.4210(f) and the recordkeeping requirements in §60.4214(b) for new emergency stationary CI ICE beginning in the following model years:]

Engine power	Starting model year
19≤KW<56 (25≤HP<75)	2013
56≤KW<130 (75≤HP<175)	2012
KW≥130 (HP≥175)	2011

Table 6 to Subpart IIII of Part 60—Optional 3-Mode Test Cycle for Stationary Fire Pump Engines

[As stated in §60.4210(g), manufacturers of fire pump engines may use the following test cycle for testing fire pump engines:]

Mode No.	Engine speed[1]	Torque (percent)[2]	Weighting factors
1	Rated	100	0.30
2	Rated	75	0.50
3	Rated	50	0.20

[1]Engine speed: ±2 percent of point.

[2]Torque: NFPA certified nameplate HP for 100 percent point. All points should be ±2 percent of engine percent load value.

Table 7 to Subpart IIII of Part 60—Requirements for Performance Tests for Stationary CI ICE With a Displacement of ≥30 Liters per Cylinder

As stated in §60.4213, you must comply with the following requirements for performance tests for stationary CI ICE with a displacement of ≥30 liters per cylinder:

Each	Complying with the requirement to	You must	Using	According to the following requirements
1. Stationary CI internal combustion engine with a displacement of ≥ 30 liters per cylinder	a. Reduce NO_x emissions by 90 percent or more;	i. Select the sampling port location and number/location of traverse points at the inlet and outlet of the control device;		(a) For NO_x, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A-1, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A-4.
		ii. Measure O_2 at the inlet and outlet of the control device;	(1) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-2	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for NO_x concentration.
		iii. If necessary, measure moisture content at the inlet and outlet of the control device; and	(2) Method 4 of 40 CFR part 60, appendix A-3, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see §60.17)	(c) Measurements to determine moisture content must be made at the same time as the measurements for NO_x concentration.
		iv. Measure NO_x at the inlet and outlet of the control device.	(3) Method 7E of 40 CFR part 60, appendix A-4, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see §60.17)	(d) NO_x concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	b. Limit the concentration of	i. Select the sampling port location and		(a) For NO_x, O_2, and moisture measurement, ducts ≤6 inches

Each	Complying with the requirement to	You must	Using	According to the following requirements
	NO_x in the stationary CI internal combustion engine exhaust.	number/location of traverse points at the exhaust of the stationary internal combustion engine;		in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A-1, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A-4.
		ii. Determine the O_2concentration of the stationary internal combustion engine exhaust at the sampling port location;	(1) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-2	(b) Measurements to determine O_2 concentration must be made at the same time as the measurement for NO_xconcentration.
		iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(2) Method 4 of 40 CFR part 60, appendix A-3, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see §60.17)	(c) Measurements to determine moisture content must be made at the same time as the measurement for NO_xconcentration.
		iv. Measure NO_x at the exhaust of the stationary internal combustion engine; if using a control device, the sampling site must be located at the outlet of the control device.	(3) Method 7E of 40 CFR part 60, Appendix A-4, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see §60.17)	(d) NO_x concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	c. Reduce PM emissions by 60	i. Select the sampling port location and the	(1) Method 1 or 1A of 40 CFR	(a) Sampling sites must be located at the inlet and outlet of

Each	Complying with the requirement to	You must	Using	According to the following requirements
	percent or more	number of traverse points;	part 60, appendix A-1	the control device.
		ii. Measure O_2 at the inlet and outlet of the control device;	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-2	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for PM concentration.
		iii. If necessary, measure moisture content at the inlet and outlet of the control device; and	(3) Method 4 of 40 CFR part 60, appendix A-3	(c) Measurements to determine and moisture content must be made at the same time as the measurements for PM concentration.
		iv. Measure PM at the inlet and outlet of the control device.	(4) Method 5 of 40 CFR part 60, appendix A-3	(d) PM concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	d. Limit the concentration of PM in the stationary CI internal combustion engine exhaust	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A-1	(a) If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location;	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-2	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for PM concentration.
		iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(3) Method 4 of 40 CFR part 60, appendix A-3	(c) Measurements to determine moisture content must be made at the same time as the measurements for PM concentration.
		iv. Measure PM at the exhaust of the stationary internal combustion engine.	(4) Method 5 of 40 CFR part 60, appendix A-3	(d) PM concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

[79 FR 11251, Feb. 27, 2014]

Table 8 to Subpart IIII of Part 60—Applicability of General Provisions to Subpart IIII

[As stated in §60.4218, you must comply with the following applicable General Provisions:]

General Provisions citation	Subject of citation	Applies to subpart	Explanation
§60.1	General applicability of the General Provisions	Yes	
§60.2	Definitions	Yes	Additional terms defined in §60.4219.
§60.3	Units and abbreviations	Yes	
§60.4	Address	Yes	
§60.5	Determination of construction or modification	Yes	
§60.6	Review of plans	Yes	
§60.7	Notification and Recordkeeping	Yes	Except that §60.7 only applies as specified in §60.4214(a).
§60.8	Performance tests	Yes	Except that §60.8 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder and engines that are not certified.
§60.9	Availability of information	Yes	
§60.10	State Authority	Yes	
§60.11	Compliance with standards and maintenance requirements	No	Requirements are specified in subpart IIII.
§60.12	Circumvention	Yes	
§60.13	Monitoring requirements	Yes	Except that §60.13 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder.
§60.14	Modification	Yes	
§60.15	Reconstruction	Yes	
§60.16	Priority list	Yes	
§60.17	Incorporations by reference	Yes	
§60.18	General control device requirements	No	
§60.19	General notification and reporting requirements	Yes	

Subpart JJJJJJ—National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources

WHAT THIS SUBPART COVERS

§63.11193 Am I subject to this subpart?

You are subject to this subpart if you own or operate an industrial, commercial, or institutional boiler as defined in §63.11237 that is located at, or is part of, an area source of hazardous air pollutants (HAP), as defined in §63.2, except as specified in §63.11195.

The Great Western Malting plant is an area source of HAP. The facility has two existing natural gas-fired hot water boilers and is adding 6 new natural gas-fired hot water boilers.

§63.11194 What is the affected source of this subpart?

(a) This subpart applies to each new, reconstructed, or existing affected source as defined in paragraphs (a)(1) and (2) of this section.

(1) The affected source of this subpart is the collection of all existing industrial, commercial, and institutional boilers within a subcategory, as listed in §63.11200 and defined in §63.11237, located at an area source.

(2) The affected source of this subpart is each new or reconstructed industrial, commercial, or institutional boiler within a subcategory, as listed in §63.11200 and as defined in §63.11237, located at an area source.

(b) An affected source is an existing source if you commenced construction or reconstruction of the affected source on or before June 4, 2010.

(c) An affected source is a new source if you commenced construction of the affected source after June 4, 2010, and the boiler meets the applicability criteria at the time you commence construction.

(d) An affected source is a reconstructed source if the boiler meets the reconstruction criteria as defined in §63.2, you commenced reconstruction after June 4, 2010, and the boiler meets the applicability criteria at the time you commence reconstruction.

(e) An existing dual-fuel fired boiler meeting the definition of gas-fired boiler, as defined in §63.11237, that meets the applicability requirements of this subpart after June 4, 2010 due to a fuel switch from gaseous fuel to solid fossil fuel, biomass, or liquid fuel is considered to be an existing source under this subpart as long as the boiler was designed to accommodate the alternate fuel.

(f) If you are an owner or operator of an area source subject to this subpart, you are exempt from the obligation to obtain a permit under 40 CFR part 70 or part 71 as a result of this subpart. You may, however, be required to obtain a title V permit due to another reason or reasons. *See* 40 CFR 70.3(a) and (b) or 71.3(a) and (b). Notwithstanding the exemption from title V permitting for area sources under this subpart, you must continue to comply with the provisions of this subpart.

[76 FR 15591, Mar. 21, 2011, as amended at 78 FR 7506, Feb. 1, 2013]

§63.11195 Are any boilers not subject to this subpart?

The types of boilers listed in paragraphs (a) through (k) of this section are not subject to this subpart and to any requirements in this subpart.

(a) Any boiler specifically listed as, or included in the definition of, an affected source in another standard(s) under this part.

(b) Any boiler specifically listed as an affected source in another standard(s) established under section 129 of the Clean Air Act.

(c) A boiler required to have a permit under section 3005 of the Solid Waste Disposal Act or covered by subpart EEE of this part (e.g., hazardous waste boilers), unless such units do not combust hazardous waste and combust comparable fuels.

(d) A boiler that is used specifically for research and development. This exemption does not include boilers that solely or primarily provide steam (or heat) to a process or for heating at a research and development facility. This exemption does not prohibit the use of the steam (or heat) generated from the boiler during research and development, however, the boiler must be concurrently and primarily engaged in research and development for the exemption to apply.

(e) A gas-fired boiler as defined in this subpart.

The two existing and six proposed natural gas-fired boilers meet this exclusion; therefore, this NESHAP does not apply. See definition of 'gas-fired boiler' in §63.11237.

(f) A hot water heater as defined in this subpart.

(g) Any boiler that is used as a control device to comply with another subpart of this part, or part 60, part 61, or part 65 of this chapter provided that at least 50 percent of the average annual heat input during any 3 consecutive calendar years to the boiler is provided by regulated gas streams that are subject to another standard.

(h) Temporary boilers as defined in this subpart.

(i) Residential boilers as defined in this subpart.

(j) Electric boilers as defined in this subpart.

(k) An electric utility steam generating unit (EGU) covered by subpart UUUUU of this part.

[76 FR 15591, Mar. 21, 2011, as amended at 78 FR 7506, Feb. 1, 2013]

§63.11196 What are my compliance dates?

(a) If you own or operate an existing affected boiler, you must achieve compliance with the applicable provisions in this subpart as specified in paragraphs (a)(1) through (3) of this section.

(1) If the existing affected boiler is subject to a work practice or management practice standard of a tune-up, you must achieve compliance with the work practice or management practice standard no later than March 21, 2014.

(2) If the existing affected boiler is subject to emission limits, you must achieve compliance with the emission limits no later than March 21, 2014.

(3) If the existing affected boiler is subject to the energy assessment requirement, you must achieve compliance with the energy assessment requirement no later than March 21, 2014.

(b) If you start up a new affected source on or before May 20, 2011, you must achieve compliance with the provisions of this subpart no later than May 20, 2011.

(c) If you start up a new affected source after May 20, 2011, you must achieve compliance with the provisions of this subpart upon startup of your affected source.

(d) If you own or operate an industrial, commercial, or institutional boiler and would be subject to this subpart except for the exemption in §63.11195(b) for commercial and industrial solid waste incineration units covered by 40 CFR part 60, subpart CCCC or subpart DDDD, and you cease combusting solid waste, you must be in compliance with this subpart on the effective date of the waste to fuel switch as specified in §60.2145(a)(2) and (3) of subpart CCCC or §60.2710(a)(2) and (3) of subpart DDDD.

[76 FR 15591, Mar. 21, 2011, as amended at 78 FR 7506, Feb. 1, 2013]

EMISSION LIMITS, WORK PRACTICE STANDARDS, EMISSION REDUCTION MEASURES, AND MANAGEMENT PRACTICES

§63.11200 What are the subcategories of boilers?

The subcategories of boilers, as defined in §63.11237 are:

(a) Coal.

(b) Biomass.

(c) Oil.

(d) Seasonal boilers.

(e) Oil-fired boilers with heat input capacity of equal to or less than 5 million British thermal units (Btu) per hour.

(f) Boilers with an oxygen trim system that maintains an optimum air-to-fuel ratio that would otherwise be subject to a biennial tune-up.

(g) Limited-use boilers.

[78 FR 7506, Feb. 1, 2013]

§63.11201 What standards must I meet?

(a) You must comply with each emission limit specified in Table 1 to this subpart that applies to your boiler.

(b) You must comply with each work practice standard, emission reduction measure, and management practice specified in Table 2 to this subpart that applies to your boiler. An energy assessment completed on or after January 1, 2008 that meets or is amended to meet the energy assessment requirements in Table 2 to this subpart satisfies the energy assessment requirement. A facility that operates under an energy management program established through energy management systems compatible with ISO 50001, that includes the affected units, also satisfies the energy assessment requirement.

(c) You must comply with each operating limit specified in Table 3 to this subpart that applies to your boiler.

(d) These standards apply at all times the affected boiler is operating, except during periods of startup and shutdown as defined in §63.11237, during which time you must comply only with Table 2 to this subpart.

[76 FR 15591, Mar. 21, 2011, as amended at 78 FR 7506, Feb. 1, 2013]

General Compliance Requirements

§63.11205 What are my general requirements for complying with this subpart?

(a) At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require you to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

(b) You must demonstrate compliance with all applicable emission limits using performance stack testing, fuel analysis, or a continuous monitoring system (CMS), including a continuous emission monitoring system (CEMS), a continuous opacity monitoring system (COMS), or a continuous parameter monitoring system (CPMS), where applicable. You may demonstrate compliance with the applicable mercury emission limit using fuel analysis if the emission rate calculated according to §63.11211(c) is less than the applicable emission limit. Otherwise, you must demonstrate compliance using stack testing.

(c) If you demonstrate compliance with any applicable emission limit through performance stack testing and subsequent compliance with operating limits (including the use of CPMS), with a CEMS, or with a COMS, you must develop a site-specific monitoring plan according to the requirements in paragraphs (c)(1) through (3) of this section for the use of any CEMS, COMS, or CPMS. This requirement also applies to you if you petition the EPA Administrator for alternative monitoring parameters under §63.8(f).

(1) For each CMS required in this section (including CEMS, COMS, or CPMS), you must develop, and submit to the Administrator for approval upon request, a site-specific monitoring plan that addresses paragraphs (c)(1)(i) through (vi) of this section. You must submit this site-specific monitoring plan, if requested, at least 60 days before your initial performance evaluation of your CMS. This requirement to develop and submit a site-specific monitoring plan does not apply to affected sources with existing CEMS or COMS operated according to the performance specifications under appendix B to part 60 of this chapter and that meet the requirements of §63.11224.

(i) Installation of the CMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (e.g., on or downstream of the last control device);

(ii) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems; and

(iii) Performance evaluation procedures and acceptance criteria (*e.g.,* calibrations).

(iv) Ongoing operation and maintenance procedures in accordance with the general requirements of §63.8(c)(1)(ii), (c)(3), and (c)(4)(ii);

(v) Ongoing data quality assurance procedures in accordance with the general requirements of §63.8(d); and

(vi) Ongoing recordkeeping and reporting procedures in accordance with the general requirements of §63.10(c) (as applicable in Table 8 to this subpart), (e)(1), and (e)(2)(i).

(2) You must conduct a performance evaluation of each CMS in accordance with your site-specific monitoring plan.

(3) You must operate and maintain the CMS in continuous operation according to the site-specific monitoring plan.

[76 FR 15591, Mar. 21, 2011, as amended at 78 FR 7506, Feb. 1, 2013]

Initial Compliance Requirements

§63.11210 What are my initial compliance requirements and by what date must I conduct them?

(a) You must demonstrate initial compliance with each emission limit specified in Table 1 to this subpart that applies to you by either conducting performance (stack) tests, as applicable, according to §63.11212 and Table 4 to this subpart or, for mercury, conducting fuel analyses, as applicable, according to §63.11213 and Table 5 to this subpart.

(b) For existing affected boilers that have applicable emission limits, you must demonstrate initial compliance with the applicable emission limits no later than 180 days after the compliance date that is specified in §63.11196 and according to the applicable provisions in §63.7(a)(2), except as provided in paragraph (j) of this section.

(c) For existing affected boilers that have applicable work practice standards, management practices, or emission reduction measures, you must demonstrate initial compliance no later than the compliance date that is specified in §63.11196 and according to the applicable provisions in §63.7(a)(2), except as provided in paragraph (j) of this section.

(d) For new or reconstructed affected boilers that have applicable emission limits, you must demonstrate initial compliance with the applicable emission limits no later than 180 days after March 21, 2011 or within 180 days after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(e) For new or reconstructed oil-fired boilers that combust 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 emission limit under this subpart and that do not use a post-combustion technology (except a wet scrubber) to reduce particulate matter (PM) or sulfur dioxide emissions, you are not subject to the PM emission limit in Table 1 of this subpart providing you monitor and record on a monthly basis the type of fuel combusted. If you intend to burn a new type of fuel or fuel mixture that does not meet the requirements of this paragraph, you must conduct a performance test within 60 days of burning the new fuel.

(f) For new or reconstructed affected boilers that have applicable work practice standards or management practices, you are not required to complete an initial performance tune-up, but you are required to complete the applicable biennial or 5-year tune-up as specified in §63.11223 no later than 25 months or 61 months, respectively, after the initial startup of the new or reconstructed affected source.

(g) For affected boilers that ceased burning solid waste consistent with §63.11196(d) and for which your initial compliance date has passed, you must demonstrate compliance within 60 days of the effective date of the waste-to-fuel switch as specified in §60.2145(a)(2) and (3) of subpart CCCC or §60.2710(a)(2) and (3) of subpart DDDD. If you have not conducted your compliance demonstration for this subpart within the previous 12 months, you must complete all compliance demonstrations for this subpart before you commence or recommence combustion of solid waste.

(h) For affected boilers that switch fuels or make a physical change to the boiler that results in the applicability of a different subcategory within subpart JJJJJJ or the boiler becoming subject to subpart JJJJJJ, you must demonstrate compliance within 180 days of the effective date of the fuel switch or the physical change. Notification of such changes must be submitted according to §63.11225(g).

(i) For boilers located at existing major sources of HAP that limit their potential to emit (e.g., make a physical change or take a permit limit) such that the existing major source becomes an area source, you must comply with the applicable provisions as specified in paragraphs (i)(1) through (3) of this section.

(1) Any such existing boiler at the existing source must demonstrate compliance with subpart JJJJJJ within 180 days of the later of March 21, 2014 or upon the existing major source commencing operation as an area source.

(2) Any new or reconstructed boiler at the existing source must demonstrate compliance with subpart JJJJJJ within 180 days of the later of March 21, 2011 or startup.

(3) Notification of such changes must be submitted according to §63.11225(g).

(j) For existing affected boilers that have not operated between the effective date of the rule and the compliance date that is specified for your source in §63.11196, you must comply with the applicable provisions as specified in paragraphs (j)(1) through (3) of this section.

(1) You must complete the initial compliance demonstration, if subject to the emission limits in Table 1 to this subpart, as specified in paragraphs (a) and (b) of this section, no later than 180 days after the re-start of the affected boiler and according to the applicable provisions in §63.7(a)(2).

(2) You must complete the initial performance tune-up, if subject to the tune-up requirements in §63.11223, by following the procedures described in §63.11223(b) no later than 30 days after the re-start of the affected boiler.

(3) You must complete the one-time energy assessment, if subject to the energy assessment requirements specified in Table 2 to this subpart, no later than the compliance date specified in §63.11196.

[76 FR 15591, Mar. 21, 2011, as amended at 78 FR 7507, Feb. 1, 2013]

§63.11211 How do I demonstrate initial compliance with the emission limits?

(a) For affected boilers that demonstrate compliance with any of the emission limits of this subpart through performance (stack) testing, your initial compliance requirements include conducting performance tests according to §63.11212 and Table 4 to this subpart, conducting a fuel analysis for each type of fuel burned in your boiler according to §63.11213 and Table 5 to this subpart, establishing operating limits according to §63.11222, Table 6 to this subpart and paragraph (b) of this section, as applicable, and conducting CMS performance evaluations according to §63.11224. For affected boilers that burn a single type of fuel, you are exempted from the compliance requirements of conducting a fuel analysis for each type of fuel burned in your boiler. For purposes of this subpart, boilers that use a supplemental fuel only for startup, unit shutdown, and transient flame stability purposes still qualify as affected boilers that burn a single type of fuel, and the supplemental fuel is not subject to the fuel analysis requirements under §63.11213 and Table 5 to this subpart.

(b) You must establish parameter operating limits according to paragraphs (b)(1) through (4) of this section.

(1) For a wet scrubber, you must establish the minimum scrubber liquid flow rate and minimum scrubber pressure drop as defined in §63.11237, as your operating limits during the three-run performance stack test. If you use a wet scrubber and you conduct separate performance stack tests for PM and mercury emissions, you must establish one set of minimum scrubber liquid flow rate and pressure drop operating limits. If you conduct multiple performance stack tests, you must set the minimum scrubber liquid flow rate and pressure drop operating limits at the highest minimum values established during the performance stack tests.

(2) For an electrostatic precipitator operated with a wet scrubber, you must establish the minimum total secondary electric power (secondary voltage and secondary current), as defined in §63.11237, as your operating limits during the three-run performance stack test.

(3) For activated carbon injection, you must establish the minimum activated carbon injection rate, as defined in §63.11237, as your operating limit during the three-run performance stack test.

(4) The operating limit for boilers with fabric filters that demonstrate continuous compliance through bag leak detection systems is that a bag leak detection system be installed according to the requirements in §63.11224, and that each fabric filter must be operated such that the bag leak detection system alarm does not sound more than 5 percent of the operating time during a 6-month period.

(c) If you elect to demonstrate compliance with an applicable mercury emission limit through fuel analysis, you must conduct fuel analyses according to §63.11213 and Table 5 to this subpart and follow the procedures in paragraphs (c)(1) through (3) of this section.

(1) If you burn more than one fuel type, you must determine the fuel type, or mixture, you could burn in your boiler that would result in the maximum emission rates of mercury.

(2) You must determine the 90th percentile confidence level fuel mercury concentration of the composite samples analyzed for each fuel type using Equation 1 of this section.

$$P_{90} = mean + (SD * t) \quad \text{(Eq. 1)}$$

Where:

P_{90} = 90th percentile confidence level mercury concentration, in pounds per million Btu.

mean = Arithmetic average of the fuel mercury concentration in the fuel samples analyzed according to §63.11213, in units of pounds per million Btu.

SD = Standard deviation of the mercury concentration in the fuel samples analyzed according to §63.11213, in units of pounds per million Btu.

t = t distribution critical value for 90th percentile (0.1) probability for the appropriate degrees of freedom (number of samples minus one) as obtained from a Distribution Critical Value Table.

(3) To demonstrate compliance with the applicable mercury emission limit, the emission rate that you calculate for your boiler using Equation 1 of this section must be less than the applicable mercury emission limit.

[76 FR 15591, Mar. 21, 2011, as amended at 78 FR 7508, Feb. 1, 2013]

§63.11212 What stack tests and procedures must I use for the performance tests?

(a) You must conduct all performance tests according to §63.7(c), (d), (f), and (h). You must also develop a site-specific test plan according to the requirements in §63.7(c).

(b) You must conduct each stack test according to the requirements in Table 4 to this subpart. Boilers that use a CEMS for carbon monoxide (CO) are exempt from the initial CO performance testing in Table 4 to this subpart and the oxygen concentration operating limit requirement specified in Table 3 to this subpart.

(c) You must conduct performance stack tests at the representative operating load conditions while burning the type of fuel or mixture of fuels that have the highest emissions potential for each regulated pollutant, and you must demonstrate initial compliance and establish your operating limits based on these performance stack tests. For subcategories with more than one emission limit, these requirements could result in the need to conduct more than one performance stack test. Following each performance stack test and until the next performance stack test, you must comply with the operating limit for operating load conditions specified in Table 3 to this subpart.

(d) You must conduct a minimum of three separate test runs for each performance stack test required in this section, as specified in §63.7(e)(3) and in accordance with the provisions in Table 4 to this subpart.

(e) To determine compliance with the emission limits, you must use the F-Factor methodology and equations in sections 12.2 and 12.3 of EPA Method 19 of appendix A-7 to part 60 of this chapter to convert the measured PM concentrations and the measured mercury concentrations that result from the performance test to pounds per million Btu heat input emission rates.

[76 FR 15591, Mar. 21, 2011, as amended at 78 FR 7508, Feb. 1, 2013]

§63.11213 What fuel analyses and procedures must I use for the performance tests?

(a) You must conduct fuel analyses according to the procedures in paragraphs (b) and (c) of this section and Table 5 to this subpart, as applicable. You are not required to conduct fuel analyses for fuels used for only startup, unit shutdown, and transient flame stability purposes. You are required to conduct fuel analyses only for fuels and units that are subject to emission limits for mercury in Table 1 of this subpart.

(b) At a minimum, you must obtain three composite fuel samples for each fuel type according to the procedures in Table 5 to this subpart. Each composite sample must consist of a minimum of three samples collected at approximately equal intervals during a test run period.

(c) Determine the concentration of mercury in the fuel in units of pounds per million Btu of each composite sample for each fuel type according to the procedures in Table 5 to this subpart.

§63.11214 How do I demonstrate initial compliance with the work practice standard, emission reduction measures, and management practice?

(a) If you own or operate an existing or new coal-fired boiler with a heat input capacity of less than 10 million Btu per hour, you must conduct a performance tune-up according to §63.11223(b) and you must submit a signed statement in the Notification of Compliance Status report that indicates that you conducted a tune-up of the boiler.

(b) If you own or operate an existing or new biomass-fired boiler or an existing or new oil-fired boiler, you must conduct a performance tune-up according to §63.11223(b) and you must submit a signed statement in the Notification of Compliance Status report that indicates that you conducted a tune-up of the boiler.

(c) If you own or operate an existing affected boiler with a heat input capacity of 10 million Btu per hour or greater, you must submit a signed certification in the Notification of Compliance Status report that an energy assessment of the boiler and its energy use systems was completed according to Table 2 to this subpart and is an accurate depiction of your facility.

(d) If you own or operate a boiler subject to emission limits in Table 1 of this subpart, you must minimize the boiler's startup and shutdown periods following the manufacturer's recommended procedures, if available. If manufacturer's recommended procedures are not available, you must follow recommended procedures for a unit of similar design for which manufacturer's recommended procedures are available. You must submit a signed statement in the Notification of Compliance Status report that indicates that you conducted startups and shutdowns according to the manufacturer's recommended procedures or procedures specified for a boiler of similar design if manufacturer's recommended procedures are not available.

[76 FR 15591, Mar. 21, 2011, as amended at 78 FR 7508, Feb. 1, 2013]

CONTINUOUS COMPLIANCE REQUIREMENTS

§63.11220 When must I conduct subsequent performance tests or fuel analyses?

(a) If your boiler has a heat input capacity of 10 million British thermal units per hour or greater, you must conduct all applicable performance (stack) tests according to §63.11212 on a triennial basis, except as specified in paragraphs (b) through (d) of this section. Triennial performance tests must be completed no more than 37 months after the previous performance test.

(b) When demonstrating initial compliance with the PM emission limit, if your boiler's performance test results show that your PM emissions are equal to or less than half of the PM emission limit, you do not need to conduct further performance tests for PM but must continue to comply with all applicable operating limits and monitoring requirements. If your initial performance test results show that your PM emissions are greater than half of the PM emission limit, you must conduct subsequent performance tests as specified in paragraph (a) of this section.

(c) If you demonstrate compliance with the mercury emission limit based on fuel analysis, you must conduct a fuel analysis according to §63.11213 for each type of fuel burned as specified in paragraphs (c)(1) and (2) of this section. If you plan to burn a new type of fuel or fuel mixture, you must conduct a fuel analysis before burning the new type of fuel or mixture in your boiler. You must recalculate the mercury emission rate using Equation 1 of §63.11211. The recalculated mercury emission rate must be less than the applicable emission limit.

(1) When demonstrating initial compliance with the mercury emission limit, if the mercury constituents in the fuel or fuel mixture are measured to be equal to or less than half of the mercury emission limit, you do not need to conduct further fuel analysis sampling but must continue to comply with all applicable operating limits and monitoring requirements.

(2) When demonstrating initial compliance with the mercury emission limit, if the mercury constituents in the fuel or fuel mixture are greater than half of the mercury emission limit, you must conduct quarterly sampling.

(d) For existing affected boilers that have not operated since the previous compliance demonstration and more than 3 years have passed since the previous compliance demonstration, you must complete your subsequent compliance demonstration no later than 180 days after the re-start of the affected boiler.

[78 FR 7508, Feb. 1, 2013]

§63.11221 Is there a minimum amount of monitoring data I must obtain?

(a) You must monitor and collect data according to this section and the site-specific monitoring plan required by §63.11205(c).

(b) You must operate the monitoring system and collect data at all required intervals at all times the affected source is operating and compliance is required, except for periods of monitoring system malfunctions or out-of-control periods (see §63.8(c)(7) of this part), repairs associated with monitoring system malfunctions or out-of-control periods, and required monitoring system quality assurance or quality control activities including, as applicable, calibration checks, required zero and span adjustments, and scheduled CMS maintenance as defined in your site-specific monitoring plan. A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You are required to complete monitoring system repairs in response to monitoring system malfunctions or out-of-control periods and to return the monitoring system to operation as expeditiously as practicable.

(c) You may not use data collected during monitoring system malfunctions or out-of-control periods, repairs associated with monitoring system malfunctions or out-of-control periods, or required monitoring system quality assurance or quality control activities in calculations used to report emissions or operating levels. Any such periods must be reported according to the requirements in §63.11225. You must use all the data collected during all other periods in assessing the operation of the control device and associated control system.

(d) Except for periods of monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, and required monitoring system quality assurance or quality control activities (including, as applicable, calibration checks, required zero and span adjustments, and scheduled CMS maintenance as defined in your site-specific monitoring plan), failure to collect required data is a deviation of the monitoring requirements.

[78 FR 7508, Feb. 1, 2013]

§63.11222 How do I demonstrate continuous compliance with the emission limits?

(a) You must demonstrate continuous compliance with each emission limit and operating limit in Tables 1 and 3 to this subpart that applies to you according to the methods specified in Table 7 to this subpart and to paragraphs (a)(1) through (4) of this section.

(1) Following the date on which the initial compliance demonstration is completed or is required to be completed under §§63.7 and 63.11196, whichever date comes first, you must continuously monitor the operating parameters. Operation above the established maximum, below the established minimum, or outside the allowable range of the operating limits specified in paragraph (a) of this section constitutes a deviation from your operating limits established under this subpart, except during performance tests

conducted to determine compliance with the emission and operating limits or to establish new operating limits. Operating limits are confirmed or reestablished during performance tests.

(2) If you have an applicable mercury or PM emission limit, you must keep records of the type and amount of all fuels burned in each boiler during the reporting period to demonstrate that all fuel types and mixtures of fuels burned would result in lower emissions of mercury than the applicable emission limit (if you demonstrate compliance through fuel analysis), or result in lower fuel input of mercury than the maximum values calculated during the last performance stack test (if you demonstrate compliance through performance stack testing).

(3) If you have an applicable mercury emission limit and you plan to burn a new type of fuel, you must determine the mercury concentration for any new fuel type in units of pounds per million Btu, using the procedures in Equation 1 of §63.11211 based on supplier data or your own fuel analysis, and meet the requirements in paragraphs (a)(3)(i) or (ii) of this section.

(i) The recalculated mercury emission rate must be less than the applicable emission limit.

(ii) If the mercury concentration is higher than mercury fuel input during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in §63.11212 to demonstrate that the mercury emissions do not exceed the emission limit.

(4) If your unit is controlled with a fabric filter, and you demonstrate continuous compliance using a bag leak detection system, you must initiate corrective action within 1 hour of a bag leak detection system alarm and operate and maintain the fabric filter system such that the alarm does not sound more than 5 percent of the operating time during a 6-month period. You must also keep records of the date, time, and duration of each alarm, the time corrective action was initiated and completed, and a brief description of the cause of the alarm and the corrective action taken. You must also record the percent of the operating time during each 6-month period that the alarm sounds. In calculating this operating time percentage, if inspection of the fabric filter demonstrates that no corrective action is required, no alarm time is counted. If corrective action is required, each alarm is counted as a minimum of 1 hour. If you take longer than 1 hour to initiate corrective action, the alarm time is counted as the actual amount of time taken to initiate corrective action.

(b) You must report each instance in which you did not meet each emission limit and operating limit in Tables 1 and 3 to this subpart that apply to you. These instances are deviations from the emission limits in this subpart. These deviations must be reported according to the requirements in §63.11225.

§63.11223 How do I demonstrate continuous compliance with the work practice and management practice standards?

(a) For affected sources subject to the work practice standard or the management practices of a tune-up, you must conduct a performance tune-up according to paragraph (b) of this section and keep records as required in §63.11225(c) to demonstrate continuous compliance. You must conduct the tune-up while burning the type of fuel (or fuels in the case of boilers that routinely burn two types of fuels at the same time) that provided the majority of the heat input to the boiler over the 12 months prior to the tune-up.

(b) Except as specified in paragraphs (c) through (f) of this section, you must conduct a tune-up of the boiler biennially to demonstrate continuous compliance as specified in paragraphs (b)(1) through (7) of this section. Each biennial tune-up must be conducted no more than 25 months after the previous tune-up. For a new or reconstructed boiler, the first biennial tune-up must be no later than 25 months after the initial startup of the new or reconstructed boiler.

(1) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may delay the burner inspection until the next scheduled unit shutdown, not to exceed 36 months from the previous inspection). Units that produce electricity for sale may delay the burner inspection until the first outage, not to exceed 36 months from the previous inspection.

(2) Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available.

(3) Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (you may delay the inspection until the next scheduled unit shutdown, not to exceed 36 months from the previous inspection). Units that produce electricity for sale may delay the inspection until the first outage, not to exceed 36 months from the previous inspection.

(4) Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any nitrogen oxide requirement to which the unit is subject.

(5) Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). Measurements may be taken using a portable CO analyzer.

(6) Maintain on-site and submit, if requested by the Administrator, a report containing the information in paragraphs (b)(6)(i) through (iii) of this section.

(i) The concentrations of CO in the effluent stream in parts per million, by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler.

(ii) A description of any corrective actions taken as a part of the tune-up of the boiler.

(iii) The type and amount of fuel used over the 12 months prior to the tune-up of the boiler, but only if the unit was physically and legally capable of using more than one type of fuel during that period. Units sharing a fuel meter may estimate the fuel use by each unit.

(7) If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 days of startup.

(c) Boilers with an oxygen trim system that maintains an optimum air-to-fuel ratio that would otherwise be subject to a biennial tune-up must conduct a tune-up of the boiler every 5 years as specified in paragraphs (b)(1) through (7) of this section. Each 5-year tune-up must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed boiler with an oxygen trim system, the first 5-year tune-up must be no later than 61 months after the initial startup. You may delay the burner inspection specified in paragraph (b)(1) of this section and inspection of the system controlling the air-to-fuel ratio specified in paragraph (b)(3) of this section until the next scheduled unit shutdown, but you must inspect each burner and system controlling the air-to-fuel ratio at least once every 72 months.

(d) Seasonal boilers must conduct a tune-up every 5 years as specified in paragraphs (b)(1) through (7) of this section. Each 5-year tune-up must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed seasonal boiler, the first 5-year tune-up must be no later than 61 months after the initial startup. You may delay the burner inspection specified in paragraph (b)(1) of this section and inspection of the system controlling the air-to-fuel ratio specified in paragraph (b)(3) of this section until the next scheduled unit shutdown, but you must inspect each burner and system controlling the air-to-fuel ratio at least once every 72 months. Seasonal boilers are not subject to the emission limits in Table 1 to this subpart or the operating limits in Table 3 to this subpart.

(e) Oil-fired boilers with a heat input capacity of equal to or less than 5 million Btu per hour must conduct a tune-up every 5 years as specified in paragraphs (b)(1) through (7) of this section. Each 5-year tune-up must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed oil-fired boiler with a heat input capacity of equal to or less than 5 million Btu per hour, the first 5-year tune-up must be no later than 61 months after the initial startup. You may delay the burner inspection specified in paragraph (b)(1) of this section and inspection of the system controlling the air-to-fuel ratio specified in paragraph (b)(3) of this section until the next scheduled unit shutdown, but you must inspect each burner and system controlling the air-to-fuel ratio at least once every 72 months.

(f) Limited-use boilers must conduct a tune-up every 5 years as specified in paragraphs (b)(1) through (7) of this section. Each 5-year tune-up must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed limited-use boiler, the first 5-year tune-up must be no later than 61 months after the initial startup. You may delay the burner inspection specified in paragraph (b)(1) of this section and inspection of the system controlling the air-to-fuel ratio specified in paragraph (b)(3) of this section until the next scheduled unit shutdown, but you must inspect each burner and system controlling the air-to-fuel ratio at least once every 72 months. Limited-use boilers are not subject to the emission limits in Table 1 to this subpart, the energy assessment requirements in Table 2 to this subpart, or the operating limits in Table 3 to this subpart.

(g) If you own or operate a boiler subject to emission limits in Table 1 of this subpart, you must minimize the boiler's startup and shutdown periods following the manufacturer's recommended procedures, if available. If manufacturer's recommended procedures are not available, you must follow recommended procedures for a unit of similar design for which manufacturer's recommended procedures are available. You must submit a signed statement in the Notification of Compliance Status report that indicates that you conducted startups and shutdowns according to the manufacturer's recommended procedures or procedures specified for a boiler of similar design if manufacturer's recommended procedures are not available.

[76 FR 15591, Mar. 21, 2011, as amended at 78 FR 7509, Feb. 1, 2013]

§63.11224 What are my monitoring, installation, operation, and maintenance requirements?

(a) If your boiler is subject to a CO emission limit in Table 1 to this subpart, you must either install, operate, and maintain a CEMS for CO and oxygen according to the procedures in paragraphs (a)(1) through (6) of this section, or install, calibrate, operate, and maintain an oxygen analyzer system, as defined in §63.11237, according to the manufacturer's recommendations and paragraphs (a)(7) and (d) of this section, as applicable, by the compliance date specified in §63.11196. Where a certified CO CEMS is used, the CO level shall be monitored at the outlet of the boiler, after any add-on controls or flue gas recirculation system and before release to the atmosphere. Boilers that use a CO CEMS are exempt from the initial CO performance testing and oxygen concentration operating limit requirements specified in §63.11211(a) of this subpart. Oxygen monitors and oxygen trim systems must be installed to monitor oxygen in the boiler flue gas, boiler firebox, or other appropriate intermediate location.

(1) Each CO CEMS must be installed, operated, and maintained according to the applicable procedures under Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B, and each oxygen CEMS must be installed, operated, and maintained according to Performance Specification 3 at 40 CFR part 60, appendix B. Both the CO and oxygen CEMS must also be installed, operated, and maintained according to the site-specific monitoring plan developed according to paragraph (c) of this section.

(2) You must conduct a performance evaluation of each CEMS according to the requirements in §63.8(e) and according to Performance Specifications 3 and 4, 4A, or 4B at 40 CFR part 60, appendix B.

(3) Each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) every 15 minutes. You must have CEMS data values from a minimum of four successive cycles of operation representing each of the four 15-minute periods in an hour, or at least two 15-minute data

values during an hour when CEMS calibration, quality assurance, or maintenance activities are being performed, to have a valid hour of data.

(4) The CEMS data must be reduced as specified in §63.8(g)(2).

(5) You must calculate hourly averages, corrected to 3 percent oxygen, from each hour of CO CEMS data in parts per million CO concentrations and determine the 10-day rolling average of all recorded readings, except as provided in §63.11221(c). Calculate a 10-day rolling average from all of the hourly averages collected for the 10-day operating period using Equation 2 of this section.

$$\text{10-day average} = \frac{\sum_{i=1}^{n} Hpvi}{n} \qquad \text{(Eq. 2)}$$

Where:

Hpvi = the hourly parameter value for hour i

n = the number of valid hourly parameter values collected over 10 boiler operating days

(6) For purposes of collecting CO data, you must operate the CO CEMS as specified in §63.11221(b). For purposes of calculating data averages, you must use all the data collected during all periods in assessing compliance, except that you must exclude certain data as specified in §63.11221(c). Periods when CO data are unavailable may constitute monitoring deviations as specified in §63.11221(d).

(7) You must operate the oxygen analyzer system at or above the minimum oxygen level that is established as the operating limit according to Table 6 to this subpart when firing the fuel or fuel mixture utilized during the most recent CO performance stack test. Operation of oxygen trim systems to meet these requirements shall not be done in a manner which compromises furnace safety.

(b) If you are using a control device to comply with the emission limits specified in Table 1 to this subpart, you must maintain each operating limit in Table 3 to this subpart that applies to your boiler as specified in Table 7 to this subpart. If you use a control device not covered in Table 3 to this subpart, or you wish to establish and monitor an alternative operating limit and alternative monitoring parameters, you must apply to the United States Environmental Protection Agency (EPA) Administrator for approval of alternative monitoring under §63.8(f).

(c) If you demonstrate compliance with any applicable emission limit through stack testing and subsequent compliance with operating limits, you must develop a site-specific monitoring plan according to the requirements in paragraphs (c)(1) through (4) of this section. This requirement also applies to you if you petition the EPA Administrator for alternative monitoring parameters under §63.8(f).

(1) For each CMS required in this section, you must develop, and submit to the EPA Administrator for approval upon request, a site-specific monitoring plan that addresses paragraphs (c)(1)(i) through (iii) of this section. You must submit this site-specific monitoring plan (if requested) at least 60 days before your initial performance evaluation of your CMS.

(i) Installation of the CMS sampling probe or other interface at a measurement location relative to each affected unit such that the measurement is representative of control of the exhaust emissions (*e.g.,* on or downstream of the last control device).

(ii) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems.

(iii) Performance evaluation procedures and acceptance criteria (*e.g.,* calibrations).

(2) In your site-specific monitoring plan, you must also address paragraphs (c)(2)(i) through (iii) of this section.

(i) Ongoing operation and maintenance procedures in accordance with the general requirements of §63.8(c)(1), (3), and (4)(ii).

(ii) Ongoing data quality assurance procedures in accordance with the general requirements of §63.8(d).

(iii) Ongoing recordkeeping and reporting procedures in accordance with the general requirements of §63.10(c), (e)(1), and (e)(2)(i).

(3) You must conduct a performance evaluation of each CMS in accordance with your site-specific monitoring plan.

(4) You must operate and maintain the CMS in continuous operation according to the site-specific monitoring plan.

(d) If you have an operating limit that requires the use of a CMS, you must install, operate, and maintain each CPMS according to the procedures in paragraphs (d)(1) through (4) of this section.

(1) The CPMS must complete a minimum of one cycle of operation every 15 minutes. You must have data values from a minimum of four successive cycles of operation representing each of the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CMS calibration, quality assurance, or maintenance activities are being performed, to have a valid hour of data.

(2) You must calculate hourly arithmetic averages from each hour of CPMS data in units of the operating limit and determine the 30-day rolling average of all recorded readings, except as provided in §63.11221(c). Calculate a 30-day rolling average from all of the hourly averages collected for the 30-day operating period using Equation 3 of this section.

$$\text{30-day average} = \frac{\sum_{i=1}^{n} Hpvi}{n} \qquad \text{(Eq. 3)}$$

Where:

Hpvi = the hourly parameter value for hour i

n = the number of valid hourly parameter values collected over 30 boiler operating days

(3) For purposes of collecting data, you must operate the CPMS as specified in §63.11221(b). For purposes of calculating data averages, you must use all the data collected during all periods in assessing compliance, except that you must exclude certain data as specified in §63.11221(c). Periods when CPMS data are unavailable may constitute monitoring deviations as specified in §63.11221(d).

(4) Record the results of each inspection, calibration, and validation check.

(e) If you have an applicable opacity operating limit under this rule, you must install, operate, certify and maintain each COMS according to the procedures in paragraphs (e)(1) through (8) of this section by the compliance date specified in §63.11196.

(1) Each COMS must be installed, operated, and maintained according to Performance Specification 1 of 40 CFR part 60, appendix B.

(2) You must conduct a performance evaluation of each COMS according to the requirements in §63.8 and according to Performance Specification 1 of 40 CFR part 60, appendix B.

(3) As specified in §63.8(c)(4)(i), each COMS must complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

(4) The COMS data must be reduced as specified in §63.8(g)(2).

(5) You must include in your site-specific monitoring plan procedures and acceptance criteria for operating and maintaining each COMS according to the requirements in §63.8(d). At a minimum, the monitoring plan must include a daily calibration drift assessment, a quarterly performance audit, and an annual zero alignment audit of each COMS.

(6) You must operate and maintain each COMS according to the requirements in the monitoring plan and the requirements of §63.8(e). You must identify periods the COMS is out of control including any periods that the COMS fails to pass a daily calibration drift assessment, a quarterly performance audit, or an annual zero alignment audit.

(7) You must calculate and record 6-minute averages from the opacity monitoring data and determine and record the daily block average of recorded readings, except as provided in §63.11221(c).

(8) For purposes of collecting opacity data, you must operate the COMS as specified in §63.11221(b). For purposes of calculating data averages, you must use all the data collected during all periods in assessing compliance, except that you must exclude certain data as specified in §63.11221(c). Periods when COMS data are unavailable may constitute monitoring deviations as specified in §63.11221(d).

(f) If you use a fabric filter bag leak detection system to comply with the requirements of this subpart, you must install, calibrate, maintain, and continuously operate the bag leak detection system as specified in paragraphs (f)(1) through (8) of this section.

(1) You must install and operate a bag leak detection system for each exhaust stack of the fabric filter.

(2) Each bag leak detection system must be installed, operated, calibrated, and maintained in a manner consistent with the manufacturer's written specifications and recommendations and in accordance with EPA-454/R-98-015 (incorporated by reference, see §63.14).

(3) The bag leak detection system must be certified by the manufacturer to be capable of detecting particulate matter emissions at concentrations of 10 milligrams per actual cubic meter or less.

(4) The bag leak detection system sensor must provide output of relative or absolute particulate matter loadings.

(5) The bag leak detection system must be equipped with a device to continuously record the output signal from the sensor.

(6) The bag leak detection system must be equipped with an audible or visual alarm system that will activate automatically when an increase in relative particulate matter emissions over a preset level is detected. The alarm must be located where it is easily heard or seen by plant operating personnel.

(7) For positive pressure fabric filter systems that do not duct all compartments or cells to a common stack, a bag leak detection system must be installed in each baghouse compartment or cell.

(8) Where multiple bag leak detectors are required, the system's instrumentation and alarm may be shared among detectors.

[76 FR 15591, Mar. 21, 2011, as amended at 78 FR 7510, Feb. 1, 2013]

§63.11225 What are my notification, reporting, and recordkeeping requirements?

(a) You must submit the notifications specified in paragraphs (a)(1) through (5) of this section to the administrator.

(1) You must submit all of the notifications in §§63.7(b); 63.8(e) and (f); and 63.9(b) through (e), (g), and (h) that apply to you by the dates specified in those sections except as specified in paragraphs (a)(2) and (4) of this section.

(2) An Initial Notification must be submitted no later than January 20, 2014 or within 120 days after the source becomes subject to the standard.

(3) If you are required to conduct a performance stack test you must submit a Notification of Intent to conduct a performance test at least 60 days before the performance stack test is scheduled to begin.

(4) You must submit the Notification of Compliance Status no later than 120 days after the applicable compliance date specified in §63.11196 unless you must conduct a performance stack test. If you must conduct a performance stack test, you must submit the Notification of Compliance Status within 60 days of completing the performance stack test. You must submit the Notification of Compliance Status in accordance with paragraphs (a)(4)(i) and (vi) of this section. The Notification of Compliance Status must include the information and certification(s) of compliance in paragraphs (a)(4)(i) through (v) of this section, as applicable, and signed by a responsible official.

(i) You must submit the information required in §63.9(h)(2), except the information listed in §63.9(h)(2)(i)(B), (D), (E), and (F). If you conduct any performance tests or CMS performance evaluations, you must submit that data as specified in paragraph (e) of this section. If you conduct any opacity or visible emission observations, or other monitoring procedures or methods, you must submit that data to the Administrator at the appropriate address listed in §63.13.

(ii) "This facility complies with the requirements in §63.11214 to conduct an initial tune-up of the boiler."

(iii) "This facility has had an energy assessment performed according to §63.11214(c)."

(iv) For units that install bag leak detection systems: "This facility complies with the requirements in §63.11224(f)."

(v) For units that do not qualify for a statutory exemption as provided in section 129(g)(1) of the Clean Air Act: "No secondary materials that are solid waste were combusted in any affected unit."

(vi) The notification must be submitted electronically using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written Notification of Compliance Status must be submitted to the Administrator at the appropriate address listed in §63.13.

(5) If you are using data from a previously conducted emission test to serve as documentation of conformance with the emission standards and operating limits of this subpart, you must include in the Notification of Compliance Status the date of the test and a summary of the results, not a complete test report, relative to this subpart.

(b) You must prepare, by March 1 of each year, and submit to the delegated authority upon request, an annual compliance certification report for the previous calendar year containing the information specified in paragraphs (b)(1) through (4) of this section. You must submit the report by March 15 if you had any instance described by paragraph (b)(3) of this section. For boilers that are subject only to a requirement to conduct a biennial or 5-year tune-up according to §63.11223(a) and not subject to emission limits or operating limits, you may prepare only a biennial or 5-year compliance report as specified in paragraphs (b)(1) and (2) of this section.

(1) Company name and address.

(2) Statement by a responsible official, with the official's name, title, phone number, email address, and signature, certifying the truth, accuracy and completeness of the notification and a statement of whether the source has complied with all the relevant standards and other requirements of this subpart. Your notification must include the following certification(s) of compliance, as applicable, and signed by a responsible official:

(i) “This facility complies with the requirements in §63.11223 to conduct a biennial or 5-year tune-up, as applicable, of each boiler.”

(ii) For units that do not qualify for a statutory exemption as provided in section 129(g)(1) of the Clean Air Act: “No secondary materials that are solid waste were combusted in any affected unit.”

(iii) “This facility complies with the requirement in §§63.11214(d) and 63.11223(g) to minimize the boiler's time spent during startup and shutdown and to conduct startups and shutdowns according to the manufacturer's recommended procedures or procedures specified for a boiler of similar design if manufacturer's recommended procedures are not available.”

(3) If the source experiences any deviations from the applicable requirements during the reporting period, include a description of deviations, the time periods during which the deviations occurred, and the corrective actions taken.

(4) The total fuel use by each affected boiler subject to an emission limit, for each calendar month within the reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by you or EPA through a petition process to be a non-waste under §241.3(c), whether the fuel(s) were processed from discarded non-hazardous secondary materials within the meaning of §241.3, and the total fuel usage amount with units of measure.

(c) You must maintain the records specified in paragraphs (c)(1) through (7) of this section.

(1) As required in §63.10(b)(2)(xiv), you must keep a copy of each notification and report that you submitted to comply with this subpart and all documentation supporting any Initial Notification or Notification of Compliance Status that you submitted.

(2) You must keep records to document conformance with the work practices, emission reduction measures, and management practices required by §63.11214 and §63.11223 as specified in paragraphs (c)(2)(i) through (vi) of this section.

(i) Records must identify each boiler, the date of tune-up, the procedures followed for tune-up, and the manufacturer's specifications to which the boiler was tuned.

(ii) For operating units that combust non-hazardous secondary materials that have been determined not to be solid waste pursuant to §241.3(b)(1) of this chapter, you must keep a record which documents how the secondary material meets each of the legitimacy criteria under §241.3(d)(1). If you combust a fuel that has been processed from a discarded non-hazardous secondary material pursuant to §241.3(b)(4) of this chapter, you must keep records as to how the operations that produced the fuel satisfies the definition of processing in §241.2 and each of the legitimacy criteria in §241.3(d)(1) of this chapter. If the fuel received a non-waste determination pursuant to the petition process submitted under §241.3(c) of this chapter, you must keep a record that documents how the fuel satisfies the requirements of the petition process. For operating units that combust non-hazardous secondary materials as fuel per §241.4, you must keep records documenting that the material is a listed non-waste under §241.4(a).

(iii) For each boiler required to conduct an energy assessment, you must keep a copy of the energy assessment report.

(iv) For each boiler subject to an emission limit in Table 1 to this subpart, you must also keep records of monthly fuel use by each boiler, including the type(s) of fuel and amount(s) used.

(v) For each boiler that meets the definition of seasonal boiler, you must keep records of days of operation per year.

(vi) For each boiler that meets the definition of limited-use boiler, you must keep a copy of the federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent and records of fuel use for the days the boiler is operating.

(3) For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation that were done to demonstrate compliance with the mercury emission limits. Supporting documentation should include results of any fuel analyses. You can use the results from one fuel analysis for multiple boilers provided they are all burning the same fuel type.

(4) Records of the occurrence and duration of each malfunction of the boiler, or of the associated air pollution control and monitoring equipment.

(5) Records of actions taken during periods of malfunction to minimize emissions in accordance with the general duty to minimize emissions in §63.11205(a), including corrective actions to restore the malfunctioning boiler, air pollution control, or monitoring equipment to its normal or usual manner of operation.

(6) You must keep the records of all inspection and monitoring data required by §§63.11221 and 63.11222, and the information identified in paragraphs (c)(6)(i) through (vi) of this section for each required inspection or monitoring.

(i) The date, place, and time of the monitoring event.

(ii) Person conducting the monitoring.

(iii) Technique or method used.

(iv) Operating conditions during the activity.

(v) Results, including the date, time, and duration of the period from the time the monitoring indicated a problem to the time that monitoring indicated proper operation.

(vi) Maintenance or corrective action taken (if applicable).

(7) If you use a bag leak detection system, you must keep the records specified in paragraphs (c)(7)(i) through (iii) of this section.

(i) Records of the bag leak detection system output.

(ii) Records of bag leak detection system adjustments, including the date and time of the adjustment, the initial bag leak detection system settings, and the final bag leak detection system settings.

(iii) The date and time of all bag leak detection system alarms, and for each valid alarm, the time you initiated corrective action, the corrective action taken, and the date on which corrective action was completed.

(d) Your records must be in a form suitable and readily available for expeditious review. You must keep each record for 5 years following the date of each recorded action. You must keep each record on-site or be accessible from a central location by computer or other means that instantly provide access at the site for at least 2 years after the date of each recorded action. You may keep the records off site for the remaining 3 years.

(e)(1) Within 60 days after the date of completing each performance test (defined in §63.2) as required by this subpart you must submit the results of the performance tests, including any associated fuel analyses, required by this subpart to EPA's WebFIRE database by using CEDRI that is accessed through EPA's CDX (www.epa.gov/cdx). Performance test data must be submitted in the file format generated through use of EPA's Electronic Reporting Tool (ERT) (see*http://www.epa.gov/ttn/chief/ert/index.html*). Only data collected using test methods on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) to EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to EPA via CDX as described earlier in this paragraph. At the discretion of the delegated authority, you must also submit these reports, including CBI, to the delegated authority in the format specified by the delegated authority. For any performance test conducted using test methods that are not listed on the ERT Web site, the owner or operator shall submit the results of the performance test in paper submissions to the Administrator at the appropriate address listed in §63.13.

(2) Within 60 days after the date of completing each CEMS performance evaluation test as defined in §63.2, you must submit relative accuracy test audit (RATA) data to EPA's CDX by using CEDRI in accordance with paragraph (e)(1) of this section. Only RATA pollutants that can be documented with the ERT (as listed on the ERT Web site) are subject to this requirement. For any performance evaluations with no corresponding RATA pollutants listed on the ERT Web site, the owner or operator shall submit the results of the performance evaluation in paper submissions to the Administrator at the appropriate address listed in §63.13.

(f) If you intend to commence or recommence combustion of solid waste, you must provide 30 days prior notice of the date upon which you will commence or recommence combustion of solid waste. The notification must identify:

(1) The name of the owner or operator of the affected source, the location of the source, the boiler(s) that will commence burning solid waste, and the date of the notice.

(2) The currently applicable subcategory under this subpart.

(3) The date on which you became subject to the currently applicable emission limits.

(4) The date upon which you will commence combusting solid waste.

(g) If you have switched fuels or made a physical change to the boiler and the fuel switch or change resulted in the applicability of a different subcategory within subpart JJJJJJ, in the boiler becoming subject to subpart JJJJJJ, or in the boiler switching out of subpart JJJJJJ due to a change to 100 percent natural gas, or you have taken a permit limit that resulted in you being subject to subpart JJJJJJ, you must provide notice of the date upon which you switched fuels, made the physical change, or took a permit limit within 30 days of the change. The notification must identify:

(1) The name of the owner or operator of the affected source, the location of the source, the boiler(s) that have switched fuels, were physically changed, or took a permit limit, and the date of the notice.

(2) The date upon which the fuel switch, physical change, or permit limit occurred.

[76 FR 15591, Mar. 21, 2011, as amended at 78 FR 7511, Feb. 1, 2013]

§63.11226 Affirmative defense for violation of emission standards during malfunction.

In response to an action to enforce the standards set forth in §63.11201 you may assert an affirmative defense to a claim for civil penalties for violations of such standards that are caused by malfunction, as defined at 40 CFR 63.2. Appropriate penalties may be assessed if you fail to meet your burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

(a) *Assertion of affirmative defense.* To establish the affirmative defense in any action to enforce such a standard, you must timely meet the reporting requirements in paragraph (b) of this section, and must prove by a preponderance of evidence that:

(1) The violation:

(i) Was caused by a sudden, infrequent, and unavoidable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner; and

(ii) Could not have been prevented through careful planning, proper design or better operation and maintenance practices; and

(iii) Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and

(iv) Was not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(2) Repairs were made as expeditiously as possible when a violation occurred; and

(3) The frequency, amount, and duration of the violation (including any bypass) were minimized to the maximum extent practicable; and

(4) If the violation resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and

(5) All possible steps were taken to minimize the impact of the violation on ambient air quality, the environment, and human health; and

(6) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and

(7) All of the actions in response to the violation were documented by properly signed, contemporaneous operating logs; and

(8) At all times, the affected source was operated in a manner consistent with good practices for minimizing emissions; and

(9) A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the violation resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of any emissions that were the result of the malfunction.

(b) *Report.* The owner or operator seeking to assert an affirmative defense shall submit a written report to the Administrator with all necessary supporting documentation, that it has met the requirements set forth in paragraph (a) of this section. This affirmative defense report shall be included in the first periodic compliance, deviation report or excess emission report otherwise required after the initial occurrence of the violation of the relevant standard (which may be the end of any applicable averaging period). If such compliance, deviation report or excess emission report is due less than 45 days after the initial occurrence of the violation, the affirmative defense report may be included in the second compliance, deviation report or excess emission report due after the initial occurrence of the violation of the relevant standard.

[78 FR 7513, Feb. 1, 2013]

OTHER REQUIREMENTS AND INFORMATION

§63.11235 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§63.1 through 63.15 apply to you.

§63.11236 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by EPA or an administrator such as your state, local, or tribal agency. If the EPA Administrator has delegated authority to your state, local, or tribal agency, then that agency has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if implementation and enforcement of this subpart is delegated to your state, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a state, local, or tribal agency under 40 CFR part 63, subpart E, the authorities contained in paragraphs (c) of this section are retained by the EPA Administrator and are not transferred to the state, local, or tribal agency.

(c) The authorities that cannot be delegated to state, local, or tribal agencies are specified in paragraphs (c)(1) through (5) of this section.

(1) Approval of an alternative non-opacity emission standard and work practice standards in §63.11223(a).

(2) Approval of alternative opacity emission standard under §63.6(h)(9).

(3) Approval of major change to test methods under §63.7(e)(2)(ii) and (f). A "major change to test method" is defined in §63.90.

(4) Approval of a major change to monitoring under §63.8(f). A "major change to monitoring" is defined in §63.90.

(5) Approval of major change to recordkeeping and reporting under §63.10(f). A "major change to recordkeeping/reporting" is defined in §63.90.

[76 FR 15591, Mar. 21, 2011, as amended at 78 FR 7513, Feb. 1, 2013]

§63.11237 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act, in §63.2 (the General Provisions), and in this section as follows:

10-day rolling average means the arithmetic mean of all valid hours of data from 10 successive operating days, except for periods of startup and shutdown and periods when the unit is not operating.

30-day rolling average means the arithmetic mean of all valid hours of data from 30 successive operating days, except for periods of startup and shutdown and periods when the unit is not operating.

Affirmative defense means, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.

Annual heat input means the heat input for the 12 months preceding the compliance demonstration.

Bag leak detection system means a group of instruments that are capable of monitoring particulate matter loadings in the exhaust of a fabric filter (*i.e.,* baghouse) in order to detect bag failures. A bag leak detection system includes, but is not limited to, an instrument that operates on electrodynamic, triboelectric, light scattering, light transmittance, or other principle to monitor relative particulate matter loadings.

Biodiesel means a mono-alkyl ester derived from biomass and conforming to ASTM D6751-11b, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels (incorporated by reference, see §63.14).

Biomass means any biomass-based solid fuel that is not a solid waste. This includes, but is not limited to, wood residue and wood products (e.g., trees, tree stumps, tree limbs, bark, lumber, sawdust, sander dust, chips, scraps, slabs, millings, and shavings); animal manure, including litter and other bedding materials; vegetative agricultural and silvicultural materials, such as logging residues (slash), nut and grain hulls and chaff (*e.g.,* almond, walnut, peanut, rice, and wheat), bagasse, orchard prunings, corn stalks, coffee bean hulls and grounds. This definition of biomass is not intended to suggest that these materials are or are not solid waste.

Biomass subcategory includes any boiler that burns any biomass and is not in the coal subcategory.

Boiler means an enclosed device using controlled flame combustion in which water is heated to recover thermal energy in the form of steam and/or hot water. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled. A device combusting solid waste, as defined in §241.3 of this chapter, is not a boiler unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Waste heat boilers, process heaters, and autoclaves are excluded from the definition of *Boiler.*

The existing and proposed hot water boilers meet this definition.

Boiler system means the boiler and associated components, such as, feedwater systems, combustion air systems, fuel systems (including burners), blowdown systems, combustion control systems, steam systems, and condensate return systems, directly connected to and serving the energy use systems.

Calendar year means the period between January 1 and December 31, inclusive, for a given year.

Coal means all solid fuels classifiable as anthracite, bituminous, sub-bituminous, or lignite by the American Society for Testing and Materials in ASTM D388 (incorporated by reference, see §63.14), coal refuse, and petroleum coke. For the purposes of this subpart, this definition of "coal" includes synthetic fuels derived from coal including, but not limited to, solvent-refined coal, coal-oil mixtures, and coal-water mixtures. Coal derived gases are excluded from this definition.

Coal subcategory includes any boiler that burns any solid fossil fuel and no more than 15 percent biomass on an annual heat input basis.

Commercial boiler means a boiler used in commercial establishments such as hotels, restaurants, and laundries to provide electricity, steam, and/or hot water.

Common stack means the exhaust of emissions from two or more affected units through a single flue. Affected units with a common stack may each have separate air pollution control systems located before the common stack, or may have a single air pollution control system located after the exhausts come together in a single flue.

Daily block average means the arithmetic mean of all valid emission concentrations or parameter levels recorded when a unit is operating measured over the 24-hour period from 12 a.m. (midnight) to 12 a.m. (midnight), except for periods of startup and shutdown and periods when the unit is not operating.

Deviation (1) Means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(i) Fails to meet any applicable requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard; or

(ii) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit.

(2) A deviation is not always a violation.

Distillate oil means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see §63.14) or diesel fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see §63.14), kerosene, and biodiesel as defined by the American Society of Testing and Materials in ASTM D6751-11b (incorporated by reference, see §63.14).

Dry scrubber means an add-on air pollution control system that injects dry alkaline sorbent (dry injection) or sprays an alkaline sorbent (spray dryer) to react with and neutralize acid gas in the exhaust stream forming a dry powder material. Sorbent injection systems used as control devices in fluidized bed boilers and process heaters are included in this definition. A dry scrubber is a dry control system.

Electric boiler means a boiler in which electric heating serves as the source of heat. Electric boilers that burn gaseous or liquid fuel during periods of electrical power curtailment or failure are included in this definition.

Electric utility steam generating unit (EGU) means a fossil fuel-fired combustion unit of more than 25 megawatts that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 megawatts electrical output to any utility power distribution system for sale is considered an electric utility steam generating unit. To be "capable of combusting" fossil fuels, an EGU would need to have these fuels allowed in their operating permits and have the appropriate fuel handling facilities on-site or otherwise available (*e.g.,* coal handling equipment, including coal storage area, belts and conveyers, pulverizers, etc.; oil storage facilities). In addition, fossil fuel-fired EGU means any EGU that fired fossil fuel for more than 10.0 percent of the average annual heat input in any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year after April 16, 2015.

Electrostatic precipitator (ESP) means an add-on air pollution control device used to capture particulate matter by charging the particles using an electrostatic field, collecting the particles using a grounded collecting surface, and transporting the particles into a hopper. An electrostatic precipitator is usually a dry control system.

Energy assessment means the following for the emission units covered by this subpart:

(1) The energy assessment for facilities with affected boilers with less than 0.3 trillion Btu per year (TBtu/year) heat input capacity will be 8 on-site technical labor hours in length maximum, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s) and any on-site energy use system(s) accounting for at least 50 percent of the affected boiler(s) energy (*e.g.,* steam, hot water, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities, within the limit of performing an 8-hour energy assessment.

(2) The energy assessment for facilities with affected boilers with 0.3 to 1.0 TBtu/year heat input capacity will be 24 on-site technical labor hours in length maximum, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s) and any on-site energy use system(s) accounting for at least 33 percent of the affected boiler(s) energy (*e.g.,* steam, hot water, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities, within the limit of performing a 24-hour energy assessment.

(3) The energy assessment for facilities with affected boilers with greater than 1.0 TBtu/year heat input capacity will be up to 24 on-site technical labor hours in length for the first TBtu/year plus 8 on-site technical labor hours for every additional 1.0 TBtu/year not to exceed 160 on-site technical hours, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s) and any on-site energy use system(s) accounting for at least 20 percent of the affected boiler(s) energy (*e.g.,* steam, hot water, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities.

(4) The on-site energy use system(s) serving as the basis for the percent of affected boiler(s) energy production, as applicable, in paragraphs (1), (2), and (3) of this definition may be segmented by production

area or energy use area as most logical and applicable to the specific facility being assessed (*e.g.,* product X manufacturing area; product Y drying area; Building Z).

Energy management program means a program that includes a set of practices and procedures designed to manage energy use that are demonstrated by the facility's energy policies, a facility energy manager and other staffing responsibilities, energy performance measurement and tracking methods, an energy saving goal, action plans, operating procedures, internal reporting requirements, and periodic review intervals used at the facility. Facilities may establish their program through energy management systems compatible with ISO 50001.

Energy use system (1) Includes the following systems located on the site of the affected boiler that use energy provided by the boiler:

(i) Process heating; compressed air systems; machine drive (motors, pumps, fans); process cooling; facility heating, ventilation, and air conditioning systems; hot water systems; building envelop; and lighting; or

(ii) Other systems that use steam, hot water, process heat, or electricity, provided by the affected boiler.

(2) Energy use systems are only those systems using energy clearly produced by affected boilers.

Equivalent means the following only as this term is used in Table 5 to this subpart:

(1) An equivalent sample collection procedure means a published voluntary consensus standard or practice (VCS) or

EPA method that includes collection of a minimum of three composite fuel samples, with each composite consisting of a minimum of three increments collected at approximately equal intervals over the test period.

(2) An equivalent sample compositing procedure means a published VCS or EPA method to systematically mix and obtain a representative subsample (part) of the composite sample.

(3) An equivalent sample preparation procedure means a published VCS or EPA method that: Clearly states that the standard, practice or method is appropriate for the pollutant and the fuel matrix; or is cited as an appropriate sample preparation standard, practice or method for the pollutant in the chosen VCS or EPA determinative or analytical method.

(4) An equivalent procedure for determining heat content means a published VCS or EPA method to obtain gross calorific (or higher heating) value.

(5) An equivalent procedure for determining fuel moisture content means a published VCS or EPA method to obtain moisture content. If the sample analysis plan calls for determining mercury using an aliquot of the dried sample, then the drying temperature must be modified to prevent vaporizing this metal. On the other hand, if metals analysis is done on an “as received” basis, a separate aliquot can be dried to determine moisture content and the mercury concentration mathematically adjusted to a dry basis.

(6) An equivalent mercury determinative or analytical procedure means a published VCS or EPA method that clearly states that the standard, practice, or method is appropriate for mercury and the fuel matrix and has a published detection limit equal or lower than the methods listed in Table 5 to this subpart for the same purpose.

Fabric filter means an add-on air pollution control device used to capture particulate matter by filtering gas streams through filter media, also known as a baghouse. A fabric filter is a dry control system.

Federally enforceable means all limitations and conditions that are enforceable by the EPA Administrator, including, but not limited to, the requirements of 40 CFR parts 60, 61, 63, and 65, requirements within any applicable state implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 40 CFR 51.24.

Fluidized bed boiler means a boiler utilizing a fluidized bed combustion process that is not a pulverized coal boiler.

Fluidized bed combustion means a process where a fuel is burned in a bed of granulated particles, which are maintained in a mobile suspension by the forward flow of air and combustion products.

Fuel type means each category of fuels that share a common name or classification. Examples include, but are not limited to, bituminous coal, sub-bituminous coal, lignite, anthracite, biomass, distillate oil, residual oil. Individual fuel types received from different suppliers are not considered new fuel types.

Gaseous fuels includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, refinery gas, hydrogen, and biogas.

The existing and proposed hot water boilers will burn only natural gas.

Gas-fired boiler includes any boiler that burns gaseous fuels not combined with any solid fuels and burns liquid fuel only during periods of gas curtailment, gas supply interruption, startups, or periodic testing on liquid fuel. Periodic testing of liquid fuel shall not exceed a combined total of 48 hours during any calendar year.

The existing and proposed hot water boilers will burn only natural gas and meet the definition as gas-fired boilers. Gas-fired boilers are exempt from this NESHAP [40 CFR §63.11195(e)]. This NESHAP does not apply.

Heat input means heat derived from combustion of fuel in a boiler and does not include the heat input from preheated combustion air, recirculated flue gases, returned condensate, or exhaust gases from other sources such as gas turbines, internal combustion engines, kilns.

Hot water heater means a closed vessel with a capacity of no more than 120 U.S. gallons in which water is heated by combustion of gaseous, liquid, or biomass fuel and hot water is withdrawn for use external to the vessel. Hot water boilers (*i.e.,* not generating steam) combusting gaseous, liquid, or biomass fuel with a heat input capacity of less than 1.6 million Btu per hour are included in this definition. The 120 U.S. gallon capacity threshold to be considered a hot water heater is independent of the 1.6 million Btu per hour heat input capacity threshold for hot water boilers. Hot water heater also means a tankless unit that provides on-demand hot water.

Hourly average means the arithmetic average of at least four CMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CMS calibration, quality assurance, or maintenance activities are being performed.

Industrial boiler means a boiler used in manufacturing, processing, mining, and refining or any other industry to provide steam, hot water, and/or electricity.

Institutional boiler means a boiler used in institutional establishments such as, but not limited to, medical centers, nursing homes, research centers, institutions of higher education, elementary and secondary schools, libraries, religious establishments, and governmental buildings to provide electricity, steam, and/or hot water.

Limited-use boiler means any boiler that burns any amount of solid or liquid fuels and has a federally enforceable average annual capacity factor of no more than 10 percent.

Liquid fuel includes, but is not limited to, distillate oil, residual oil, any form of liquid fuel derived from petroleum, used oil meeting the specification in 40 CFR 279.11, liquid biofuels, biodiesel, and vegetable oil, and comparable fuels as defined under 40 CFR 261.38.

Load fraction means the actual heat input of a boiler divided by heat input during the performance test that established the minimum sorbent injection rate or minimum activated carbon injection rate, expressed as a fraction (*e.g.,*for 50 percent load the load fraction is 0.5).

Minimum activated carbon injection rate means load fraction multiplied by the lowest hourly average activated carbon injection rate measured according to Table 6 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limit.

Minimum oxygen level means the lowest hourly average oxygen level measured according to Table 6 to this subpart during the most recent performance stack test demonstrating compliance with the applicable carbon monoxide emission limit.

Minimum scrubber liquid flow rate means the lowest hourly average scrubber liquid flow rate (*e.g.,* to the particulate matter scrubber) measured according to Table 6 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limit.

Minimum scrubber pressure drop means the lowest hourly average scrubber pressure drop measured according to Table 6 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limit.

Minimum sorbent injection rate means:

(1) The load fraction multiplied by the lowest hourly average sorbent injection rate for each sorbent measured according to Table 6 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limits; or

(2) For fluidized bed combustion, the lowest average ratio of sorbent to sulfur measured during the most recent performance test.

Minimum total secondary electric power means the lowest hourly average total secondary electric power determined from the values of secondary voltage and secondary current to the electrostatic precipitator measured according to Table 6 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limits.

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 gas, as defined by the American Society for Testing and Materials in ASTM D1835 (incorporated by reference, see §63.14); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions (*i.e.,* a temperature of 288 Kelvin, a relative humidity of 60 percent, and a pressure of 101.3 kilopascals). Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot); or

(4) Propane or propane-derived synthetic natural gas. Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure C_3H_8.

Oil subcategory includes any boiler that burns any liquid fuel and is not in either the biomass or coal subcategories. Gas-fired boilers that burn liquid fuel only during periods of gas curtailment, gas supply interruptions, startups, or for periodic testing are not included in this definition. Periodic testing on liquid fuel shall not exceed a combined total of 48 hours during any calendar year.

Opacity means the degree to which emissions reduce the transmission of light and obscure the view of an object in the background.

Operating day means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the boiler unit. It is not necessary for fuel to be combusted for the entire 24-hour period.

Oxygen analyzer system means all equipment required to determine the oxygen content of a gas stream and used to monitor oxygen in the boiler flue gas, boiler firebox, or other appropriate intermediate location. This definition includes oxygen trim systems.

Oxygen trim system means a system of monitors that is used to maintain excess air at the desired level in a combustion device. A typical system consists of a flue gas oxygen and/or carbon monoxide monitor that automatically provides a feedback signal to the combustion air controller.

Particulate matter (PM) means any finely divided solid or liquid material, other than uncombined water, as measured by the test methods specified under this subpart, or an approved alternative method.

Performance testing means the collection of data resulting from the execution of a test method used (either by stack testing or fuel analysis) to demonstrate compliance with a relevant emission standard.

Period of gas curtailment or supply interruption means a period of time during which the supply of gaseous fuel to an affected boiler is restricted or halted for reasons beyond the control of the facility. The act of entering into a contractual agreement with a supplier of natural gas established for curtailment purposes does not constitute a reason that is under the control of a facility for the purposes of this definition. An increase in the cost or unit price of natural gas due to normal market fluctuations not during periods of supplier delivery restriction does not constitute a period of natural gas curtailment or supply interruption. On-site gaseous fuel system emergencies or equipment failures qualify as periods of supply interruption when the emergency or failure is beyond the control of the facility.

Process heater means an enclosed device using controlled flame, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material (e.g., glycol or a mixture of glycol and water) for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not come into direct contact with process materials. Process heaters include units that heat water/water mixtures for pool heating, sidewalk heating, cooling tower water heating, power washing, or oil heating.

Qualified energy assessor means:

(1) Someone who has demonstrated capabilities to evaluate energy savings opportunities for steam generation and major energy using systems, including, but not limited to:

(i) Boiler combustion management.

(ii) Boiler thermal energy recovery, including

(A) Conventional feed water economizer,

(B) Conventional combustion air preheater, and

(C) Condensing economizer.

(iii) Boiler blowdown thermal energy recovery.

(iv) Primary energy resource selection, including

(A) Fuel (primary energy source) switching, and

(B) Applied steam energy versus direct-fired energy versus electricity.

(v) Insulation issues.

(vi) Steam trap and steam leak management.

(vii) Condensate recovery.

(viii) Steam end-use management.

(2) Capabilities and knowledge includes, but is not limited to:

(i) Background, experience, and recognized abilities to perform the assessment activities, data analysis, and report preparation.

(ii) Familiarity with operating and maintenance practices for steam or process heating systems.

(iii) Additional potential steam system improvement opportunities including improving steam turbine operations and reducing steam demand.

(iv) Additional process heating system opportunities including effective utilization of waste heat and use of proper process heating methods.

(v) Boiler-steam turbine cogeneration systems.

(vi) Industry specific steam end-use systems.

Regulated gas stream means an offgas stream that is routed to a boiler for the purpose of achieving compliance with a standard under another subpart of this part or part 60, part 61, or part 65 of this chapter.

Residential boiler means a boiler used to provide heat and/or hot water and/or as part of a residential combined heat and power system. This definition includes boilers located at an institutional facility (*e.g.,* university campus, military base, church grounds) or commercial/industrial facility (*e.g.,* farm) used primarily to provide heat and/or hot water for:

(1) A dwelling containing four or fewer families, or

(2) A single unit residence dwelling that has since been converted or subdivided into condominiums or apartments.

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 of Testing and Materials in ASTM D396-10 (incorporated by reference, see §63.14(b)).

Responsible official means responsible official as defined in §70.2.

Seasonal boiler means a boiler that undergoes a shutdown for a period of at least 7 consecutive months (or 210 consecutive days) each 12-month period due to seasonal conditions, except for periodic testing. Periodic testing shall not exceed a combined total of 15 days during the 7-month shutdown. This definition only applies to boilers that would otherwise be included in the biomass subcategory or the oil subcategory.

Shutdown means the cessation of operation of a boiler for any purpose. Shutdown begins either when none of the steam or heat from the boiler is supplied for heating and/or producing electricity, or for any other purpose, or at the point of no fuel being fired in the boiler, whichever is earlier. Shutdown ends when there is no steam and no heat being supplied and no fuel being fired in the boiler.

Solid fossil fuel includes, but is not limited to, coal, coke, petroleum coke, and tire-derived fuel.

Solid fuel means any solid fossil fuel or biomass or bio-based solid fuel.

Startup means either the first-ever firing of fuel in a boiler for the purpose of supplying steam or heat for heating and/or producing electricity, or for any other purpose, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam or heat from the boiler is supplied for heating and/or producing electricity, or for any other purpose.

Temporary boiler means any gaseous or liquid fuel boiler that is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A boiler is not a temporary boiler if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The boiler or a replacement remains at a location within the facility and performs the same or similar function for more than 12 consecutive months, unless the regulatory agency approves an extension. An extension may be granted by the regulating agency upon petition by the owner or operator of a unit specifying the basis for such a request. Any temporary boiler that replaces a temporary boiler at a location within the facility and performs the same or similar function will be included in calculating the consecutive time period unless there is a gap in operation of 12 months or more.

(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.

(4) The equipment is moved from one location to another within the facility but continues to perform the same or similar function and serve the same electricity, steam, and/or hot water system in an attempt to circumvent the residence time requirements of this definition.

Tune-up means adjustments made to a boiler in accordance with the procedures outlined in §63.11223(b).

Vegetable oil means oils extracted from vegetation.

Voluntary Consensus Standards (VCS) mean technical standards (*e.g.,* materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. EPA/Office of Air Quality Planning and Standards, by precedent, has only used VCS that are written in English. Examples of VCS bodies are: American Society of Testing and Materials (ASTM 100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428-B2959, (800) 262-1373, *http://www.astm.org*), American Society of Mechanical Engineers (ASME ASME, Three Park Avenue, New York, NY 10016-5990, (800) 843-2763, *http://www.asme.org*), International Standards Organization (ISO 1, ch. de la Voie-Creuse, Case postale 56, CH-1211 Geneva 20, Switzerland, +41 22 749 01 11, *http://www.iso.org/iso/home.htm*), Standards Australia (AS Level 10, The Exchange Centre, 20 Bridge Street, Sydney, GPO Box 476, Sydney NSW 2001, + 61 2 9237 6171 *http://www.stadards.org.au*), British Standards Institution (BSI, 389 Chiswick High Road, London, W4 4AL, United Kingdom, +44 (0)20 8996 9001,*http://www.bsigroup.com*), Canadian Standards Association (CSA 5060 Spectrum Way, Suite 100, Mississauga, Ontario L4W 5N6, Canada, 800-463-6727, *http://www.csa.ca*), European Committee for Standardization (CEN CENELEC Management Centre Avenue Marnix 17 B-1000 Brussels, Belgium +32 2 550 08 11, *http://www.cen.eu/cen*), and German Engineering Standards (VDI VDI Guidelines Department, P.O. Box 10 11 39 40002, Duesseldorf, Germany, +49 211 6214-230, *http://www.vdi.eu*). The types of standards that are not considered VCS are standards developed by: the United States, *e.g.,* California (CARB) and Texas (TCEQ); industry groups, such as American Petroleum Institute (API), Gas Processors Association (GPA), and Gas Research Institute (GRI); and other branches of the U.S. government, *e.g.,*Department of Defense (DOD) and Department of Transportation (DOT). This does not preclude EPA from using standards developed by groups that are not VCS bodies within their rule. When this occurs, EPA has done searches and reviews for VCS equivalent to these non-EPA methods.

Waste heat boiler means a device that recovers normally unused energy (*i.e.,* hot exhaust gas) and converts it to usable heat. Waste heat boilers are also referred to as heat recovery steam generators. Waste heat boilers are heat exchangers generating steam from incoming hot exhaust gas from an industrial (*e.g.,* thermal oxidizer, kiln, furnace) or power (*e.g.,* combustion turbine, engine) equipment. Duct burners are sometimes used to increase the temperature of the incoming hot exhaust gas.

Wet scrubber means any add-on air pollution control device that mixes an aqueous stream or slurry with the exhaust gases from a boiler to control emissions of particulate matter or to absorb and neutralize acid gases, such as hydrogen chloride. A wet scrubber creates an aqueous stream or slurry as a byproduct of the emissions control process.

Work practice standard means any design, equipment, work practice, or operational standard, or combination thereof, which is promulgated pursuant to section 112(h) of the Clean Air Act.

[76 FR 15591, Mar. 21, 2011, as amended at 78 FR 7513, Feb. 1, 2013]

Table 1 to Subpart JJJJJ of Part 63—Emission Limits

As stated in §63.11201, you must comply with the following applicable emission limits:

If your boiler is in this subcategory . . .	For the following pollutants . . .	You must achieve less than or equal to the following emission limits, except during periods of startup and shutdown . . .
1. New coal-fired boilers with heat input capacity of 30 million British thermal units per hour (MMBtu/hr) or greater that do not meet the definition of limited-use boiler	a. PM (Filterable) b. Mercury c. CO	3.0E-02 pounds(lb) per million British thermal units (MMBtu) of heat input. 2.2E-05 lb per MMBtu of heat input. 420 parts per million (ppm) by volume on a dry basis corrected to 3 percent oxygen (3-run average or 10-day rolling average).
2. New coal-fired boilers with heat input capacity of between 10 and 30 MMBtu/hr that do not meet the definition of limited-use boiler	a. PM (Filterable) b. Mercury c. CO	4.2E-01 lb per MMBtu of heat input. 2.2E-05 lb per MMBtu of heat input. 420 ppm by volume on a dry basis corrected to 3 percent oxygen (3-run average or 10-day rolling average).
3. New biomass-fired boilers with heat input capacity of 30 MMBtu/hr or greater that do not meet the definition of seasonal boiler or limited-use boiler	PM (Filterable)	3.0E-02 lb per MMBtu of heat input.
4. New biomass fired boilers with heat input capacity of between 10 and 30 MMBtu/hr that do not meet the definition of seasonal boiler or limited-use boiler	PM (Filterable)	7.0E-02 lb per MMBtu of heat input.
5. New oil-fired boilers with heat input capacity of 10 MMBtu/hr or greater that do not meet the definition of seasonal boiler or limited-use boiler	PM (Filterable)	3.0E-02 lb per MMBtu of heat input.
6. Existing coal-fired boilers with heat input capacity of 10 MMBtu/hr or greater that do not meet the definition of limited-use boiler	a. Mercury b. CO	2.2E-05 lb per MMBtu of heat input. 420 ppm by volume on a dry basis corrected to 3 percent oxygen.

[78 FR 7517, Feb. 1, 2013]

Table 2 to Subpart JJJJJJ of Part 63—Work Practice Standards, Emission Reduction Measures, and Management Practices

As stated in §63.11201, you must comply with the following applicable work practice standards, emission reduction measures, and management practices:

If your boiler is in this subcategory . . .	You must meet the following . . .
1. Existing or new coal-fired, new biomass-fired, or new oil-fired boilers (units with heat input capacity of 10 MMBtu/hr or greater)	Minimize the boiler's startup and shutdown periods and conduct startups and shutdowns according to the manufacturer's recommended procedures. If manufacturer's recommended procedures are not available, you must follow recommended procedures for a unit of similar design for which manufacturer's recommended procedures are available.
2. Existing coal-fired boilers with heat input capacity of less than 10 MMBtu/hr	Conduct an initial tune-up as specified in §63.11214, and conduct a tune-up of the boiler biennially as specified in §63.11223.

that do not meet the definition of limited-use boiler, or use an oxygen trim system that maintains an optimum air-to-fuel ratio	
3. New coal-fired boilers with heat input capacity of less than 10 MMBtu/hr that do not meet the definition of limited-use boiler, or use an oxygen trim system that maintains an optimum air-to-fuel ratio	Conduct a tune-up of the boiler biennially as specified in §63.11223.
4. Existing oil-fired boilers with heat input capacity greater than 5 MMBtu/hr that do not meet the definition of seasonal boiler or limited-use boiler, or use an oxygen trim system that maintains an optimum air-to-fuel ratio	Conduct an initial tune-up as specified in §63.11214, and conduct a tune-up of the boiler biennially as specified in §63.11223.
5. New oil-fired boilers with heat input capacity greater than 5 MMBtu/hr that do not meet the definition of seasonal boiler or limited-use boiler, or use an oxygen trim system that maintains an optimum air-to-fuel ratio	Conduct a tune-up of the boiler biennially as specified in §63.11223.
6. Existing biomass-fired boilers that do not meet the definition of seasonal boiler or limited-use boiler, or use an oxygen trim system that maintains an optimum air-to-fuel ratio	Conduct an initial tune-up as specified in §63.11214, and conduct a tune-up of the boiler biennially as specified in §63.11223.
7. New biomass-fired boilers that do not meet the definition of seasonal boiler or limited-use boiler, or use an oxygen trim system that maintains an optimum air-to-fuel ratio	Conduct a tune-up of the boiler biennially as specified in §63.11223.
8. Existing seasonal boilers	Conduct an initial tune-up as specified in §63.11214, and conduct a tune-up of the boiler every 5 years as specified in §63.11223.
9. New seasonal boilers	Conduct a tune-up of the boiler every 5 years as specified in §63.11223.
10. Existing limited-use boilers	Conduct an initial tune-up as specified in §63.11214, and conduct a tune-up of the boiler every 5 years as specified in §63.11223.
11. New limited-use boilers	Conduct a tune-up of the boiler every 5 years as specified in §63.11223.
12. Existing oil-fired boilers with heat input capacity of equal to or less than 5 MMBtu/hr	Conduct an initial tune-up as specified in §63.11214, and conduct a tune-up of the boiler every 5 years as specified in §63.11223.
13. New oil-fired boilers with heat input capacity of equal to or less than 5 MMBtu/hr	Conduct a tune-up of the boiler every 5 years as specified in §63.11223.
14. Existing coal-fired, biomass-fired, or oil-fired boilers with an oxygen trim	Conduct an initial tune-up as specified in §63.11214, and conduct a tune-up of the boiler every 5 years as specified in §63.11223.

system that maintains an optimum air-to-fuel ratio that would otherwise be subject to a biennial tune-up	
15. New coal-fired, biomass-fired, or oil-fired boilers with an oxygen trim system that maintains an optimum air-to-fuel ratio that would otherwise be subject to a biennial tune-up	Conduct a tune-up of the boiler every 5 years as specified in §63.11223.
16. Existing coal-fired, biomass-fired, or oil-fired boilers (units with heat input capacity of 10 MMBtu/hr and greater), not including limited-use boilers	Must have a one-time energy assessment performed by a qualified energy assessor. An energy assessment completed on or after January 1, 2008, that meets or is amended to meet the energy assessment requirements in this table satisfies the energy assessment requirement. Energy assessor approval and qualification requirements are waived in instances where past or amended energy assessments are used to meet the energy assessment requirements. A facility that operates under an energy management program compatible with ISO 50001 that includes the affected units also satisfies the energy assessment requirement. The energy assessment must include the following with extent of the evaluation for items (1) to (4) appropriate for the on-site technical hours listed in §63.11237:
	(1) A visual inspection of the boiler system,
	(2) An evaluation of operating characteristics of the affected boiler systems, specifications of energy use systems, operating and maintenance procedures, and unusual operating constraints,
	(3) An inventory of major energy use systems consuming energy from affected boiler(s) and which are under control of the boiler owner or operator,
	(4) A review of available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage,
	(5) A list of major energy conservation measures that are within the facility's control,
	(6) A list of the energy savings potential of the energy conservation measures identified, and
	(7) A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.

[78 FR 7518, Feb. 1, 2013]

Table 3 to Subpart JJJJJJ of Part 63—Operating Limits for Boilers With Emission Limits

As stated in §63.11201, you must comply with the applicable operating limits:

If you demonstrate compliance with applicable emission	You must meet these operating limits except during periods of startup and shutdown . . .

limits using . . .	
1. Fabric filter control	a. Maintain opacity to less than or equal to 10 percent opacity (daily block average); OR b. Install and operate a bag leak detection system according to §63.11224 and operate the fabric filter such that the bag leak detection system alarm does not sound more than 5 percent of the operating time during each 6-month period.
2. Electrostatic precipitator control	a. Maintain opacity to less than or equal to 10 percent opacity (daily block average); OR b. Maintain the 30-day rolling average total secondary electric power of the electrostatic precipitator at or above the minimum total secondary electric power as defined in §63.11237.
3. Wet scrubber control	Maintain the 30-day rolling average pressure drop across the wet scrubber at or above the minimum scrubber pressure drop as defined in §63.11237 and the 30-day rolling average liquid flow rate at or above the minimum scrubber liquid flow rate as defined in §63.11237.
4. Dry sorbent or activated carbon injection control	Maintain the 30-day rolling average sorbent or activated carbon injection rate at or above the minimum sorbent injection rate or minimum activated carbon injection rate as defined in §63.11237. When your boiler operates at lower loads, multiply your sorbent or activated carbon injection rate by the load fraction (*e.g.*, actual heat input divided by the heat input during the performance stack test; for 50 percent load, multiply the injection rate operating limit by 0.5).
5. Any other add-on air pollution control type.	This option is for boilers that operate dry control systems. Boilers must maintain opacity to less than or equal to 10 percent opacity (daily block average).
6. Fuel analysis	Maintain the fuel type or fuel mixture (annual average) such that the mercury emission rate calculated according to §63.11211(c) are less than the applicable emission limit for mercury.
7. Performance stack testing	For boilers that demonstrate compliance with a performance stack test, maintain the operating load of each unit such that it does not exceed 110 percent of the average operating load recorded during the most recent performance stack test.
8. Oxygen analyzer system	For boilers subject to a CO emission limit that demonstrate compliance with an oxygen analyzer system as specified in §63.11224(a), maintain the 30-day rolling average oxygen level at or above the minimum oxygen level as defined in §63.11237. This requirement does not apply to units that install an oxygen trim system since these units will set the trim system to the level specified in §63.11224(a)(7).

[78 FR 7519, Feb. 1, 2013]

Table 4 to Subpart JJJJJJ of Part 63—Performance (Stack) Testing Requirements

As stated in §63.11212, you must comply with the following requirements for performance (stack) test for affected sources:

To conduct a performance test for the following pollutant. . .	You must. . .	Using. . .
1. Particulate Matter	a. Select sampling ports	Method 1 in appendix A-1 to part 60 of this chapter.

	location and the number of traverse points	
	b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G in appendix A-2 to part 60 of this chapter.
	c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B in appendix A-2 to part 60 of this chapter, or ASTM D6522-00 (Reapproved 2005),[a] or ANSI/ASME PTC 19.10-1981.[a]
	d. Measure the moisture content of the stack gas	Method 4 in appendix A-3 to part 60 of this chapter.
	e. Measure the particulate matter emission concentration	Method 5 or 17 (positive pressure fabric filters must use Method 5D) in appendix A-3 and A-6 to part 60 of this chapter and a minimum 1 dscm of sample volume per run.
	f. Convert emissions concentration to lb/MMBtu emission rates	Method 19 F-factor methodology in appendix A-7 to part 60 of this chapter.
2. Mercury	a. Select sampling ports location and the number of traverse points	Method 1 in appendix A-1 to part 60 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G in appendix A-2 to part 60 of this chapter.
	c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B in appendix A-2 to part 60 of this chapter, or ASTM D6522-00 (Reapproved 2005),[a] or ANSI/ASME PTC 19.10-1981.[a]
	d. Measure the moisture content of the stack gas	Method 4 in appendix A-3 to part 60 of this chapter.
	e. Measure the mercury emission concentration	Method 29, 30A, or 30B in appendix A-8 to part 60 of this chapter or Method 101A in appendix B to part 61 of this chapter or ASTM Method D6784-02.[a]Collect a minimum 2 dscm of sample volume with Method 29 of 101A per run. Use a minimum run time of 2 hours with Method 30A.
	f. Convert emissions concentration to lb/MMBtu emission rates	Method 19 F-factor methodology in appendix A-7 to part 60 of this chapter.
3. Carbon Monoxide	a. Select the sampling ports location and the number of traverse points	Method 1 in appendix A-1 to part 60 of this chapter.
	b. Determine oxygen and carbon dioxide concentrations of the	Method 3A or 3B in appendix A-2 to part 60 of this chapter, or ASTM D6522-00 (Reapproved 2005),[a] or ANSI/ASME PTC 19.10-1981.[a]

	stack gas	
	c. Measure the moisture content of the stack gas	Method 4 in appendix A-3 to part 60 of this chapter.
	d. Measure the carbon monoxide emission concentration	Method 10, 10A, or 10B in appendix A-4 to part 60 of this chapter or ASTM D6522-00 (Reapproved 2005)[a] and a minimum 1 hour sampling time per run.

[a]Incorporated by reference, see §63.14.

Table 5 to Subpart JJJJJJ of Part 63—Fuel Analysis Requirements

As stated in §63.11213, you must comply with the following requirements for fuel analysis testing for affected sources:

To conduct a fuel analysis for the following pollutant . . .	You must. . .	Using . . .
1. Mercury	a. Collect fuel samples	Procedure in §63.11213(b) or ASTM D2234/D2234M[a] (for coal) or ASTM D6323[a] (for biomass) or equivalent.
	b. Compose fuel samples	Procedure in §63.11213(b) or equivalent.
	c. Prepare composited fuel samples	EPA SW-846-3050B[a] (for solid samples) or EPA SW-846-3020A[a](for liquid samples) or ASTM D2013/D2013M[a] (for coal) or ASTM D5198[a] (for biomass) or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865[a] (for coal) or ASTM E711[a] (for biomass) or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173[a] or ASTM E871[a] or equivalent.
	f. Measure mercury concentration in fuel sample	ASTM D6722[a] (for coal) or EPA SW-846-7471B[a] (for solid samples) or EPA SW-846-7470A[a] (for liquid samples) or equivalent.
	g. Convert concentrations into units of lb/MMBtu of heat content	

[a]Incorporated by reference, see §63.14.

Table 6 to Subpart JJJJJJ of Part 63—Establishing Operating Limits

As stated in §63.11211, you must comply with the following requirements for establishing operating limits:

If you have an applicable	And your operating	You must . . .	Using . . .	According to the following requirements

emission limit for . . .	limits are based on . . .			
1. PM or mercury	a. Wet scrubber operating parameters	Establish site-specific minimum scrubber pressure drop and minimum scrubber liquid flow rate operating limits according to §63.11211(b)	Data from the pressure drop and liquid flow rate monitors and the PM or mercury performance stack tests	(a) You must collect pressure drop and liquid flow rate data every 15 minutes during the entire period of the performance stack tests;
				(b) Determine the average pressure drop and liquid flow rate for each individual test run in the three-run performance stack test by computing the average of all the 15-minute readings taken during each test run.
	b. Electrostatic precipitator operating parameters	Establish a site-specific minimum total secondary electric power operating limit according to §63.11211(b)	Data from the secondary electric power monitors and the PM or mercury performance stack tests	(a) You must collect secondary electric power data every 15 minutes during the entire period of the performance stack tests;
				(b) Determine the average total secondary electric power for each individual test run in the three-run performance stack test by computing the average of all the 15-minute readings taken during each test run.
2. Mercury	Dry sorbent or activated carbon injection rate operating parameters	Establish a site-specific minimum sorbent or activated carbon injection rate operating limit according to §63.11211(b)	Data from the sorbent or activated carbon injection rate monitors and the mercury performance stack tests	(a) You must collect sorbent or activated carbon injection rate data every 15 minutes during the entire period of the performance stack tests;
				(b) Determine the average sorbent or activated carbon injection rate for each individual test run in the three-run performance stack test by computing the average of all the 15-minute readings taken during each test run.
				(c) When your unit operates at lower loads, multiply your

				sorbent or activated carbon injection rate by the load fraction (e.g., actual heat input divided by heat input during performance stack test, for 50 percent load, multiply the injection rate operating limit by 0.5) to determine the required injection rate.
3. CO	Oxygen	Establish a unit-specific limit for minimum oxygen level	Data from the oxygen analyzer system specified in §63.11224(a)	(a) You must collect oxygen data every 15 minutes during the entire period of the performance stack tests;
				(b) Determine the average hourly oxygen concentration for each individual test run in the three-run performance stack test by computing the average of all the 15-minute readings taken during each test run.
4. Any pollutant for which compliance is demonstrated by a performance stack test	Boiler operating load	Establish a unit-specific limit for maximum operating load according to §63.11212(c)	Data from the operating load monitors (fuel feed monitors or steam generation monitors)	(a) You must collect operating load data (fuel feed rate or steam generation data) every 15 minutes during the entire period of the performance test.
				(b) Determine the average operating load by computing the hourly averages using all of the 15-minute readings taken during each performance test.
				(c) Determine the average of the three test run averages during the performance test, and multiply this by 1.1 (110 percent) as your operating limit.

[78 FR 7520, Feb. 1, 2013]

Table 7 to Subpart JJJJJJ of Part 63—Demonstrating Continuous Compliance

As stated in §63.11222, you must show continuous compliance with the emission limitations for affected sources according to the following:

If you must meet the following operating limits . . .	You must demonstrate continuous compliance by . . .
1. Opacity	a. Collecting the opacity monitoring system data according to §63.11224(e) and §63.11221; and

	b. Reducing the opacity monitoring data to 6-minute averages; and
	c. Maintaining opacity to less than or equal to 10 percent (daily block average).
2. Fabric Filter Bag Leak Detection Operation	Installing and operating a bag leak detection system according to §63.11224(f) and operating the fabric filter such that the requirements in §63.11222(a)(4) are met.
3. Wet Scrubber Pressure Drop and Liquid Flow Rate	a. Collecting the pressure drop and liquid flow rate monitoring system data according to §§63.11224 and 63.11221; and
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average pressure drop and liquid flow rate at or above the minimum pressure drop and minimum liquid flow rate according to §63.11211.
4. Dry Scrubber Sorbent or Activated Carbon Injection Rate	a. Collecting the sorbent or activated carbon injection rate monitoring system data for the dry scrubber according to §§63.11224 and 63.11221; and
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average sorbent or activated carbon injection rate at or above the minimum sorbent or activated carbon injection rate according to §63.11211.
5. Electrostatic Precipitator Total Secondary Electric Power	a. Collecting the total secondary electric power monitoring system data for the electrostatic precipitator according to §§63.11224 and 63.11221; and
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average total secondary electric power at or above the minimum total secondary electric power according to §63.11211.
6. Fuel Pollutant Content	a. Only burning the fuel types and fuel mixtures used to demonstrate compliance with the applicable emission limit according to §63.11213 as applicable; and
	b. Keeping monthly records of fuel use according to §§63.11222(a)(2) and 63.11225(b)(4).
7. Oxygen content	a. Continuously monitoring the oxygen content of flue gas according to §63.11224 (This requirement does not apply to units that install an oxygen trim system since these units will set the trim system to the level specified in §63.11224(a)(7)); and
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average oxygen content at or above the minimum oxygen level established during the most recent CO performance test.
8. CO emissions	a. Continuously monitoring the CO concentration in the combustion exhaust according to §§63.11224 and 63.11221; and
	b. Correcting the data to 3 percent oxygen, and reducing the data to 1-hour averages; and
	c. Reducing the data from the hourly averages to 10-day rolling averages; and

	d. Maintaining the 10-day rolling average CO concentration at or below the applicable emission limit in Table 1 to this subpart.
9. Boiler operating load	a. Collecting operating load data (fuel feed rate or steam generation data) every 15 minutes; and
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average at or below the operating limit established during the performance test according to §63.11212(c) and Table 6 to this subpart.

[78 FR 7521, Feb. 1, 2013]

Table 8 to Subpart JJJJJJ of Part 63—Applicability of General Provisions to Subpart JJJJJJ

As stated in §63.11235, you must comply with the applicable General Provisions according to the following:

General provisions cite	Subject	Does it apply?
§63.1	Applicability	Yes.
§63.2	Definitions	Yes. Additional terms defined in §63.11237.
§63.3	Units and Abbreviations	Yes.
§63.4	Prohibited Activities and Circumvention	Yes.
§63.5	Preconstruction Review and Notification Requirements	No
§63.6(a), (b)(1)-(b)(5), (b)(7), (c), (f)(2)-(3), (g), (i), (j)	Compliance with Standards and Maintenance Requirements	Yes.
§63.6(e)(1)(i)	General Duty to minimize emissions	No. *See* §63.11205 for general duty requirement.
§63.6(e)(1)(ii)	Requirement to correct malfunctions ASAP	No.
§63.6(e)(3)	SSM Plan	No.
§63.6(f)(1)	SSM exemption	No.
§63.6(h)(1)	SSM exemption	No.
§63.6(h)(2) to (9)	Determining compliance with opacity emission standards	Yes.
§63.7(a), (b), (c), (d) , (e)(2)-(e)(9), (f), (g), and (h)	Performance Testing Requirements	Yes.
§63.7(e)(1)	Performance testing	No. *See* §63.11210.
§63.8(a), (b), (c)(1), (c)(1)(ii), (c)(2) to	Monitoring Requirements	Yes.

(c)(9), (d)(1) and (d)(2), (e),(f), and (g)		
§63.8(c)(1)(i)	General duty to minimize emissions and CMS operation	No.
§63.8(c)(1)(iii)	Requirement to develop SSM Plan for CMS	No.
§63.8(d)(3)	Written procedures for CMS	Yes, except for the last sentence, which refers to an SSM plan. SSM plans are not required.
§63.9	Notification Requirements	Yes, excluding the information required in §63.9(h)(2)(i)(B), (D), (E) and (F). See §63.11225.
§63.10(a) and (b)(1)	Recordkeeping and Reporting Requirements	Yes.
§63.10(b)(2)(i)	Recordkeeping of occurrence and duration of startups or shutdowns	No.
§63.10(b)(2)(ii)	Recordkeeping of malfunctions	No. *See* §63.11225 for recordkeeping of (1) occurrence and duration and (2) actions taken during malfunctions.
§63.10(b)(2)(iii)	Maintenance records	Yes.
§63.10(b)(2)(iv) and (v)	Actions taken to minimize emissions during SSM	No.
§63.10(b)(2)(vi)	Recordkeeping for CMS malfunctions	Yes.
§63.10(b)(2)(vii) to (xiv)	Other CMS requirements	Yes.
§63.10(b)(3)	Recordkeeping requirements for applicability determinations	No.
§63.10(c)(1) to (9)	Recordkeeping for sources with CMS	Yes.
§63.10(c)(10)	Recording nature and cause of malfunctions	No. *See* §63.11225 for malfunction recordkeeping requirements.
§63.10(c)(11)	Recording corrective actions	No. *See* §63.11225 for malfunction recordkeeping requirements.
§63.10(c)(12) and (13)	Recordkeeping for sources with CMS	Yes.
§63.10(c)(15)	Allows use of SSM plan	No.
§63.10(d)(1) and (2)	General reporting requirements	Yes.

§63.10(d)(3)	Reporting opacity or visible emission observation results	No.
§63.10(d)(4)	Progress reports under an extension of compliance	Yes.
§63.10(d)(5)	SSM reports	No. *See* §63.11225 for malfunction reporting requirements.
§63.10(e)	Additional reporting requirements for sources with CMS	Yes.
§63.10(f)	Waiver of recordkeeping or reporting requirements	Yes.
§63.11	Control Device Requirements	No.
§63.12	State Authority and Delegation	Yes.
§63.13-63.16	Addresses, Incorporation by Reference, Availability of Information, Performance Track Provisions	Yes.
§63.1(a)(5), (a)(7)-(a)(9), (b)(2), (c)(3)-(4), (d), 63.6(b)(6), (c)(3), (c)(4), (d), (e)(2), (e)(3)(ii), (h)(3), (h)(5)(iv), 63.8(a)(3), 63.9(b)(3), (h)(4), 63.10(c)(2)-(4), (c)(9)	Reserved	No.

[76 FR 15591, Mar. 21, 2011, as amended at 78 FR 7521, Feb. 1, 2013]

Subpart ZZZZ—National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

WHAT THIS SUBPART COVERS

§63.6580 What is the purpose of subpart ZZZZ?

Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and operating limitations.

[73 FR 3603, Jan. 18, 2008]

§63.6585 Am I subject to this subpart?

You are subject to this subpart if you own or operate a stationary RICE at a major or area source of HAP emissions, except if the stationary RICE is being tested at a stationary RICE test cell/stand.

Great Western Malting owns and operates a RICE emergency generator engine at the Pocatello plant, an area source of HAP (Table 5-4). The emergency generator is subject to the requirements in this rule.

(a) A stationary RICE is any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

(b) A major source of HAP emissions is a plant site that emits or has the potential to emit any single HAP at a rate of 10 tons (9.07 megagrams) or more per year or any combination of HAP at a rate of 25 tons (22.68 megagrams) or more per year, except that for oil and gas production facilities, a major source of HAP emissions is determined for each surface site.

(c) An area source of HAP emissions is a source that is not a major source.

(d) If you are an owner or operator of an area source subject to this subpart, your status as an entity subject to a standard or other requirements under this subpart does not subject you to the obligation to obtain a permit under 40 CFR part 70 or 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart as applicable.

(e) If you are an owner or operator of a stationary RICE used for national security purposes, you may be eligible to request an exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C.

(f) The emergency stationary RICE listed in paragraphs (f)(1) through (3) of this section are not subject to this subpart. The stationary RICE must meet the definition of an emergency stationary RICE in §63.6675, which includes operating according to the provisions specified in §63.6640(f).

(1) Existing residential emergency stationary RICE located at an area source of HAP emissions that do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii) and that do not operate for the purpose specified in §63.6640(f)(4)(ii).

(2) Existing commercial emergency stationary RICE located at an area source of HAP emissions that do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii) and that do not operate for the purpose specified in §63.6640(f)(4)(ii).

(3) Existing institutional emergency stationary RICE located at an area source of HAP emissions that do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii) and that do not operate for the purpose specified in §63.6640(f)(4)(ii).

[69 FR 33506, June 15, 2004, as amended at 73 FR 3603, Jan. 18, 2008; 78 FR 6700, Jan. 30, 2013]

§63.6590 What parts of my plant does this subpart cover?

This subpart applies to each affected source.

(a) *Affected source.* An affected source is any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions, excluding stationary RICE being tested at a stationary RICE test cell/stand.

(1) *Existing stationary RICE*.

(i) For stationary RICE with a site rating of more than 500 brake horsepower (HP) located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before December 19, 2002.

(ii) For stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iii) For stationary RICE located at an area source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

The RICE emergency generator at the plant was constructed in 1980 and meets the definition as an existing stationary RICE.

(iv) A change in ownership of an existing stationary RICE does not make that stationary RICE a new or reconstructed stationary RICE.

(2) *New stationary RICE.* (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(3) *Reconstructed stationary RICE.* (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after June 12, 2006.

(b) *Stationary RICE subject to limited requirements.* (1) An affected source which meets either of the criteria in paragraphs (b)(1)(i) through (ii) of this section does not have to meet the requirements of this subpart and of subpart A of this part except for the initial notification requirements of §63.6645(f).

(i) The stationary RICE is a new or reconstructed emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that does not operate or is not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii).

(ii) The stationary RICE is a new or reconstructed limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(2) A new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis must meet the initial notification requirements of §63.6645(f) and the requirements of §§63.6625(c), 63.6650(g), and 63.6655(c). These stationary RICE do not have to meet the emission limitations and operating limitations of this subpart.

(3) The following stationary RICE do not have to meet the requirements of this subpart and of subpart A of this part, including initial notification requirements:

(i) Existing spark ignition 2 stroke lean burn (2SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(ii) Existing spark ignition 4 stroke lean burn (4SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(iii) Existing emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that does not operate or is not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii).

(iv) Existing limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(v) Existing stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(c) *Stationary RICE subject to Regulations under 40 CFR Part 60.* An affected source that meets any of the criteria in paragraphs (c)(1) through (7) of this section must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part.

(1) A new or reconstructed stationary RICE located at an area source;

(2) A new or reconstructed 2SLB stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(3) A new or reconstructed 4SLB stationary RICE with a site rating of less than 250 brake HP located at a major source of HAP emissions;

(4) A new or reconstructed spark ignition 4 stroke rich burn (4SRB) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(5) A new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(6) A new or reconstructed emergency or limited use stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(7) A new or reconstructed compression ignition (CI) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3604, Jan. 18, 2008; 75 FR 9674, Mar. 3, 2010; 75 FR 37733, June 30, 2010; 75 FR 51588, Aug. 20, 2010; 78 FR 6700, Jan. 30, 2013]

§63.6595 When do I have to comply with this subpart?

(a) *Affected sources.* (1) If you have an existing stationary RICE, excluding existing non-emergency CI stationary RICE, with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the applicable emission limitations, operating limitations and other requirements no later than June 15, 2007. If you have an existing non-emergency CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, an existing stationary CI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary CI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations, operating limitations, and other requirements no later than May 3, 2013. If you have an existing stationary SI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary SI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations, operating limitations, and other requirements no later than October 19, 2013.

The compliance date for this rule for the existing diesel emergency generator was 5/13/2013.

(2) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart no later than August 16, 2004.

(3) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions after August 16, 2004, you must comply with the

applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(4) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(5) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(6) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(7) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(b) *Area sources that become major sources.* If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, the compliance dates in paragraphs (b)(1) and (2) of this section apply to you.

(1) Any stationary RICE for which construction or reconstruction is commenced after the date when your area source becomes a major source of HAP must be in compliance with this subpart upon startup of your affected source.

(2) Any stationary RICE for which construction or reconstruction is commenced before your area source becomes a major source of HAP must be in compliance with the provisions of this subpart that are applicable to RICE located at major sources within 3 years after your area source becomes a major source of HAP.

(c) If you own or operate an affected source, you must meet the applicable notification requirements in §63.6645 and in 40 CFR part 63, subpart A.

The existing 60 HP emergency generator is not subject to notification requirements because it meets the exclusions in §63.6645.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3604, Jan. 18, 2008; 75 FR 9675, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010; 78 FR 6701, Jan. 30, 2013]

EMISSION AND OPERATING LIMITATIONS

§63.6600 What emission limitations and operating limitations must I meet if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart.

(a) If you own or operate an existing, new, or reconstructed spark ignition 4SRB stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 1a to this subpart and the operating limitations in Table 1b to this subpart which apply to you.

(b) If you own or operate a new or reconstructed 2SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, a new or reconstructed 4SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, or a new or reconstructed CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

(c) If you own or operate any of the following stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the emission limitations in Tables 1a, 2a, 2c, and 2d to this subpart or operating limitations in Tables 1b and 2b to this subpart: an existing 2SLB stationary RICE; an existing 4SLB stationary RICE; a stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis; an emergency stationary RICE; or a limited use stationary RICE.

(d) If you own or operate an existing non-emergency stationary CI RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2c to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 9675, Mar. 3, 2010]

§63.6601 What emission limitations must I meet if I own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP and less than or equal to 500 brake HP located at a major source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart. If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at major source of HAP emissions manufactured on or after January 1, 2008, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 9675, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010]

§63.6602 What emission limitations and other requirements must I meet if I own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations and other requirements in Table 2c to this subpart which apply to you. Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart.

[78 FR 6701, Jan. 30, 2013]

§63.6603 What emission limitations, operating limitations, and other requirements must I meet if I own or operate an existing stationary RICE located at an area source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart.

(a) If you own or operate an existing stationary RICE located at an area source of HAP emissions, you must comply with the requirements in Table 2d to this subpart and the operating limitations in Table 2b to this subpart that apply to you.

The requirements in Table 2d, Item 4 for existing emergency generators apply to the emergency generator at the Pocatello plant. Those requirements include:

- Change oil and filter every 500 hours of operation or annually, whichever comes first
- Inspect air cleaner every 1000 hours of operation or annually, whichever comes first
- Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.

None of the operating limitations in Table 2b applies to the emergency generator.

(b) If you own or operate an existing stationary non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP that meets either paragraph (b)(1) or (2) of this section, you do not have to meet the numerical CO emission limitations specified in Table 2d of this subpart. Existing stationary non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP that meet either paragraph (b)(1) or (2) of this section must meet the management practices that are shown for stationary non-emergency CI RICE with a site rating of less than or equal to 300 HP in Table 2d of this subpart.

(1) The area source is located in an area of Alaska that is not accessible by the Federal Aid Highway System (FAHS).

(2) The stationary RICE is located at an area source that meets paragraphs (b)(2)(i), (ii), and (iii) of this section.

(i) The only connection to the FAHS is through the Alaska Marine Highway System (AMHS), or the stationary RICE operation is within an isolated grid in Alaska that is not connected to the statewide electrical grid referred to as the Alaska Railbelt Grid.

(ii) At least 10 percent of the power generated by the stationary RICE on an annual basis is used for residential purposes.

(iii) The generating capacity of the area source is less than 12 megawatts, or the stationary RICE is used exclusively for backup power for renewable energy.

(c) If you own or operate an existing stationary non-emergency CI RICE with a site rating of more than 300 HP located on an offshore vessel that is an area source of HAP and is a nonroad vehicle that is an Outer Continental Shelf (OCS) source as defined in 40 CFR 55.2, you do not have to meet the numerical CO emission limitations specified in Table 2d of this subpart. You must meet all of the following management practices:

(1) Change oil every 1,000 hours of operation or annually, whichever comes first. Sources have the option to utilize an oil analysis program as described in §63.6625(i) in order to extend the specified oil change requirement.

(2) Inspect and clean air filters every 750 hours of operation or annually, whichever comes first, and replace as necessary.

(3) Inspect fuel filters and belts, if installed, every 750 hours of operation or annually, whichever comes first, and replace as necessary.

(4) Inspect all flexible hoses every 1,000 hours of operation or annually, whichever comes first, and replace as necessary.

(d) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 1 or Tier 2 emission standards in Table 1 of 40 CFR 89.112 and that is subject to an enforceable state or local standard that requires the engine to be replaced no later than June 1, 2018, you may until January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018, choose to comply with the management practices that are shown for stationary non-emergency CI RICE with a site rating of less than or equal to 300 HP in Table 2d of this subpart instead of the applicable emission limitations in Table 2d, operating limitations in Table 2b, and crankcase ventilation system requirements in §63.6625(g). You must comply with the emission limitations in Table 2d and operating limitations in Table 2b that apply for non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions by January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018. You must also comply with the crankcase ventilation system requirements in §63.6625(g) by January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018.

(e) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 3 (Tier 2 for engines above 560 kilowatt (kW)) emission standards in Table 1 of 40 CFR 89.112, you may comply with the requirements under this part by meeting the requirements for Tier 3 engines (Tier 2 for engines above 560 kW) in 40 CFR part 60 subpart IIII instead of the emission limitations and other requirements that would otherwise apply under this part for existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions.

(f) An existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP must meet the definition of remote stationary RICE in §63.6675 on the initial compliance date for the engine, October 19, 2013, in order to be considered a remote stationary RICE under this subpart. Owners and operators of existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP that meet the definition of remote stationary RICE in §63.6675 of this subpart as of October 19, 2013 must evaluate the status of their stationary RICE every 12 months. Owners and operators must keep records of the initial and annual evaluation of the status of the engine. If the evaluation indicates that the stationary RICE no longer meets the definition of remote stationary RICE in §63.6675 of this subpart, the owner or operator must comply with all of the requirements for existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP that are not remote stationary RICE within 1 year of the evaluation.

[75 FR 9675, Mar. 3, 2010, as amended at 75 FR 51589, Aug. 20, 2010; 76 FR 12866, Mar. 9, 2011; 78 FR 6701, Jan. 30, 2013]

§63.6604 What fuel requirements must I meet if I own or operate a stationary CI RICE?

(a) If you own or operate an existing non-emergency, non-black start CI stationary RICE with a site rating of more than 300 brake HP with a displacement of less than 30 liters per cylinder that uses diesel fuel, you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel.

(b) Beginning January 1, 2015, if you own or operate an existing emergency CI stationary RICE with a site rating of more than 100 brake HP and a displacement of less than 30 liters per cylinder that uses diesel fuel and operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii) or that operates for the purpose specified in §63.6640(f)(4)(ii), you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to January 1, 2015, may be used until depleted.

The diesel emergency generator is 60 HP and is not subject to this fuel requirement.

(c) Beginning January 1, 2015, if you own or operate a new emergency CI stationary RICE with a site rating of more than 500 brake HP and a displacement of less than 30 liters per cylinder located at a major source of HAP that uses diesel fuel and operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii), you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to January 1, 2015, may be used until depleted.

(d) Existing CI stationary RICE located in Guam, American Samoa, the Commonwealth of the Northern Mariana Islands, at area sources in areas of Alaska that meet either §63.6603(b)(1) or §63.6603(b)(2), or are on offshore vessels that meet §63.6603(c) are exempt from the requirements of this section.

[78 FR 6702, Jan. 30, 2013]

General Compliance Requirements

§63.6605 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limitations, operating limitations, and other requirements in this subpart that apply to you at all times.

This requirement applies to the emergency generator. The emergency generator is in compliance.

(b) At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require you to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

This requirement applies to the emergency generator. The emergency generator operates in compliance with Subpart ZZZZ requirements.

[75 FR 9675, Mar. 3, 2010, as amended at 78 FR 6702, Jan. 30, 2013]

Testing and Initial Compliance Requirements

§63.6610 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

These requirements do not apply to the 60 HP emergency generator at the area source of HAPs.

If you own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct the initial performance test or other initial compliance demonstrations in Table 4 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in §63.6595 and according to the provisions in §63.7(a)(2).

(b) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must demonstrate initial compliance with either the proposed emission limitations or the promulgated emission limitations no later than February 10, 2005 or no later than 180 days after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(c) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, and you chose to comply with the proposed emission limitations when demonstrating initial compliance, you must conduct a second performance test to demonstrate compliance with the promulgated emission limitations by December 13, 2007 or after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(d) An owner or operator is not required to conduct an initial performance test on units for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (d)(1) through (5) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

(5) The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3605, Jan. 18, 2008]

§63.6611 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a new or reconstructed 4SLB SI stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions?

If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must conduct an initial performance test within 240 days after the compliance date that is specified for your stationary RICE in §63.6595 and according to the provisions specified in Table 4 to this subpart, as appropriate.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 51589, Aug. 20, 2010]

§63.6612 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct any initial performance test or other initial compliance demonstration according to Tables 4 and 5 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in §63.6595 and according to the provisions in §63.7(a)(2).

(b) An owner or operator is not required to conduct an initial performance test on a unit for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (b)(1) through (4) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

[75 FR 9676, Mar. 3, 2010, as amended at 75 FR 51589, Aug. 20, 2010]

§63.6615 When must I conduct subsequent performance tests?

If you must comply with the emission limitations and operating limitations, you must conduct subsequent performance tests as specified in Table 3 of this subpart.

§63.6620 What performance tests and other procedures must I use?

(a) You must conduct each performance test in Tables 3 and 4 of this subpart that applies to you.

(b) Each performance test must be conducted according to the requirements that this subpart specifies in Table 4 to this subpart. If you own or operate a non-operational stationary RICE that is subject to performance testing, you do not need to start up the engine solely to conduct the performance test. Owners and operators of a non-operational engine can conduct the performance test when the engine is started up again. The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load for the stationary RICE listed in paragraphs (b)(1) through (4) of this section.

(1) Non-emergency 4SRB stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(2) New non-emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP located at a major source of HAP emissions.

(3) New non-emergency 2SLB stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(4) New non-emergency CI stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(c) [Reserved]

(d) You must conduct three separate test runs for each performance test required in this section, as specified in §63.7(e)(3). Each test run must last at least 1 hour, unless otherwise specified in this subpart.

(e)(1) You must use Equation 1 of this section to determine compliance with the percent reduction requirement:

$$\frac{C_i - C_o}{C_i} \times 100 = R \quad (Eq.\ 1)$$

Where:

C_i = concentration of carbon monoxide (CO), total hydrocarbons (THC), or formaldehyde at the control device inlet,

C_o = concentration of CO, THC, or formaldehyde at the control device outlet, and

R = percent reduction of CO, THC, or formaldehyde emissions.

(2) You must normalize the CO, THC, or formaldehyde concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen, or an equivalent percent carbon dioxide (CO_2). If pollutant concentrations are to be corrected to 15 percent oxygen and CO_2 concentration is measured in lieu of oxygen concentration measurement, a CO_2correction factor is needed. Calculate the CO_2 correction factor as described in paragraphs (e)(2)(i) through (iii) of this section.

(i) Calculate the fuel-specific F_o value for the fuel burned during the test using values obtained from Method 19, Section 5.2, and the following equation:

$$F_o = \frac{0.209\ F_d}{F_c} \quad (Eq.\ 2)$$

Where:

F_o = Fuel factor based on the ratio of oxygen volume to the ultimate CO_2 volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is oxygen, percent/100.

F_d = Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm^3/J (dscf/10^6 Btu).

F_c = Ratio of the volume of CO_2 produced to the gross calorific value of the fuel from Method 19, dsm^3/J (dscf/10^6 Btu)

(ii) Calculate the CO_2 correction factor for correcting measurement data to 15 percent O_2, as follows:

$$X_{CO2} = \frac{5.9}{F_o} \quad (Eq.\ 3)$$

Where:

X_{CO2} = CO_2 correction factor, percent.

5.9 = 20.9 percent O_2—15 percent O_2, the defined O_2 correction value, percent.

(iii) Calculate the CO, THC, and formaldehyde gas concentrations adjusted to 15 percent O_2 using CO_2 as follows:

$$C_{adj} = C_d \frac{X_{CO2}}{\%CO_2} \quad (Eq. 4)$$

Where:

C_{adj} = Calculated concentration of CO, THC, or formaldehyde adjusted to 15 percent O_2.

C_d = Measured concentration of CO, THC, or formaldehyde, uncorrected.

X_{CO2} = CO_2 correction factor, percent.

$\%CO_2$ = Measured CO_2 concentration measured, dry basis, percent.

(f) If you comply with the emission limitation to reduce CO and you are not using an oxidation catalyst, if you comply with the emission limitation to reduce formaldehyde and you are not using NSCR, or if you comply with the emission limitation to limit the concentration of formaldehyde in the stationary RICE exhaust and you are not using an oxidation catalyst or NSCR, you must petition the Administrator for operating limitations to be established during the initial performance test and continuously monitored thereafter; or for approval of no operating limitations. You must not conduct the initial performance test until after the petition has been approved by the Administrator.

(g) If you petition the Administrator for approval of operating limitations, your petition must include the information described in paragraphs (g)(1) through (5) of this section.

(1) Identification of the specific parameters you propose to use as operating limitations;

(2) A discussion of the relationship between these parameters and HAP emissions, identifying how HAP emissions change with changes in these parameters, and how limitations on these parameters will serve to limit HAP emissions;

(3) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(4) A discussion identifying the methods you will use to measure and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(5) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(h) If you petition the Administrator for approval of no operating limitations, your petition must include the information described in paragraphs (h)(1) through (7) of this section.

(1) Identification of the parameters associated with operation of the stationary RICE and any emission control device which could change intentionally (*e.g.,* operator adjustment, automatic controller adjustment, etc.) or unintentionally (*e.g.,*wear and tear, error, etc.) on a routine basis or over time;

(2) A discussion of the relationship, if any, between changes in the parameters and changes in HAP emissions;

(3) For the parameters which could change in such a way as to increase HAP emissions, a discussion of whether establishing limitations on the parameters would serve to limit HAP emissions;

(4) For the parameters which could change in such a way as to increase HAP emissions, a discussion of how you could establish upper and/or lower values for the parameters which would establish limits on the parameters in operating limitations;

(5) For the parameters, a discussion identifying the methods you could use to measure them and the instruments you could use to monitor them, as well as the relative accuracy and precision of the methods and instruments;

(6) For the parameters, a discussion identifying the frequency and methods for recalibrating the instruments you could use to monitor them; and

(7) A discussion of why, from your point of view, it is infeasible or unreasonable to adopt the parameters as operating limitations.

(i) The engine percent load during a performance test must be determined by documenting the calculations, assumptions, and measurement devices used to measure or estimate the percent load in a specific application. A written report of the average percent load determination must be included in the notification of compliance status. The following information must be included in the written report: the engine model number, the engine manufacturer, the year of purchase, the manufacturer's site-rated brake horsepower, the ambient temperature, pressure, and humidity during the performance test, and all assumptions that were made to estimate or calculate percent load during the performance test must be clearly explained. If measurement devices such as flow meters, kilowatt meters, beta analyzers, stain gauges, etc. are used, the model number of the measurement device, and an estimate of its accurate in percentage of true value must be provided.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9676, Mar. 3, 2010; 78 FR 6702, Jan. 30, 2013]

§63.6625 What are my monitoring, installation, collection, operation, and maintenance requirements?

(a) If you elect to install a CEMS as specified in Table 5 of this subpart, you must install, operate, and maintain a CEMS to monitor CO and either O_2 or CO_2 according to the requirements in paragraphs (a)(1) through (4) of this section. If you are meeting a requirement to reduce CO emissions, the CEMS must be installed at both the inlet and outlet of the control device. If you are meeting a requirement to limit the concentration of CO, the CEMS must be installed at the outlet of the control device.

(1) Each CEMS must be installed, operated, and maintained according to the applicable performance specifications of 40 CFR part 60, appendix B.

(2) You must conduct an initial performance evaluation and an annual relative accuracy test audit (RATA) of each CEMS according to the requirements in §63.8 and according to the applicable performance specifications of 40 CFR part 60, appendix B as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.

(3) As specified in §63.8(c)(4)(ii), each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. You must have at least two data points, with each representing a different 15-minute period, to have a valid hour of data.

(4) The CEMS data must be reduced as specified in §63.8(g)(2) and recorded in parts per million or parts per billion (as appropriate for the applicable limitation) at 15 percent oxygen or the equivalent CO_2 concentration.

(b) If you are required to install a continuous parameter monitoring system (CPMS) as specified in Table 5 of this subpart, you must install, operate, and maintain each CPMS according to the requirements in paragraphs (b)(1) through (6) of this section. For an affected source that is complying with the emission limitations and operating limitations on March 9, 2011, the requirements in paragraph (b) of this section are applicable September 6, 2011.

(1) You must prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraphs (b)(1)(i) through (v) of this section and in §63.8(d). As specified in §63.8(f)(4), you may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in paragraphs (b)(1) through (5) of this section in your site-specific monitoring plan.

(i) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations;

(ii) Sampling interface (*e.g.,* thermocouple) location such that the monitoring system will provide representative measurements;

(iii) Equipment performance evaluations, system accuracy audits, or other audit procedures;

(iv) Ongoing operation and maintenance procedures in accordance with provisions in §63.8(c)(1)(ii) and (c)(3); and

(v) Ongoing reporting and recordkeeping procedures in accordance with provisions in §63.10(c), (e)(1), and (e)(2)(i).

(2) You must install, operate, and maintain each CPMS in continuous operation according to the procedures in your site-specific monitoring plan.

(3) The CPMS must collect data at least once every 15 minutes (see also §63.6635).

(4) For a CPMS for measuring temperature range, the temperature sensor must have a minimum tolerance of 2.8 degrees Celsius (5 degrees Fahrenheit) or 1 percent of the measurement range, whichever is larger.

(5) You must conduct the CPMS equipment performance evaluation, system accuracy audits, or other audit procedures specified in your site-specific monitoring plan at least annually.

(6) You must conduct a performance evaluation of each CPMS in accordance with your site-specific monitoring plan.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must monitor and record your fuel usage daily with separate fuel meters to measure the volumetric flow rate of each fuel. In addition, you must operate your stationary RICE in a manner which reasonably minimizes HAP emissions.

(d) If you are operating a new or reconstructed emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must install a non-resettable hour meter prior to the startup of the engine.

(e) If you own or operate any of the following stationary RICE, you must operate and maintain the stationary RICE and after-treatment control device (if any) according to the manufacturer's emission-related written instructions or develop your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions:

(1) An existing stationary RICE with a site rating of less than 100 HP located at a major source of HAP emissions;

(2) An existing emergency or black start stationary RICE with a site rating of less than or equal to 500 HP located at a major source of HAP emissions;

(3) An existing emergency or black start stationary RICE located at an area source of HAP emissions;

The emergency generator meets this definition and must operate and maintain the engine according to a maintenance plan. The site performs maintenance on the emergency generator according to their maintenance system and meets these requirements.

(4) An existing non-emergency, non-black start stationary CI RICE with a site rating less than or equal to 300 HP located at an area source of HAP emissions;

(5) An existing non-emergency, non-black start 2SLB stationary RICE located at an area source of HAP emissions;

(6) An existing non-emergency, non-black start stationary RICE located at an area source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis.

(7) An existing non-emergency, non-black start 4SLB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(8) An existing non-emergency, non-black start 4SRB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(9) An existing, non-emergency, non-black start 4SLB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year; and

(10) An existing, non-emergency, non-black start 4SRB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year.

(f) If you own or operate an existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing emergency stationary RICE located at an area source of HAP emissions, you must install a non-resettable hour meter if one is not already installed.

The emergency generator at the plant has a non-resettable hour meter.

(g) If you own or operate an existing non-emergency, non-black start CI engine greater than or equal to 300 HP that is not equipped with a closed crankcase ventilation system, you must comply with either paragraph (g)(1) or paragraph (2) of this section. Owners and operators must follow the manufacturer's specified maintenance requirements for operating and maintaining the open or closed crankcase ventilation systems and replacing the crankcase filters, or can request the Administrator to approve different maintenance requirements that are as protective as manufacturer requirements. Existing CI engines located at area sources in areas of Alaska that meet either §63.6603(b)(1) or §63.6603(b)(2) do not have to meet the requirements of this paragraph (g). Existing CI engines located on offshore vessels that meet §63.6603(c) do not have to meet the requirements of this paragraph (g).

(1) Install a closed crankcase ventilation system that prevents crankcase emissions from being emitted to the atmosphere, or

(2) Install an open crankcase filtration emission control system that reduces emissions from the crankcase by filtering the exhaust stream to remove oil mist, particulates and metals.

(h) If you operate a new, reconstructed, or existing stationary engine, you must minimize the engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the emission standards applicable to all times other than startup in Tables 1a, 2a, 2c, and 2d to this subpart apply.

The plant operates the emergency generator in accordance with this requirement.

(i) If you own or operate a stationary CI engine that is subject to the work, operation or management practices in items 1 or 2 of Table 2c to this subpart or in items 1 or 4 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Base Number is less than 30 percent of the Total Base Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

(j) If you own or operate a stationary SI engine that is subject to the work, operation or management practices in items 6, 7, or 8 of Table 2c to this subpart or in items 5, 6, 7, 9, or 11 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Acid Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Acid Number increases by more than 3.0 milligrams of potassium hydroxide (KOH) per gram from Total Acid Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3606, Jan. 18, 2008; 75 FR 9676, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010; 76 FR 12866, Mar. 9, 2011; 78 FR 6703, Jan. 30, 2013]

§63.6630 How do I demonstrate initial compliance with the emission limitations, operating limitations, and other requirements?

(a) You must demonstrate initial compliance with each emission limitation, operating limitation, and other requirement that applies to you according to Table 5 of this subpart.

There are no requirements in Table 5 that apply.

(b) During the initial performance test, you must establish each operating limitation in Tables 1b and 2b of this subpart that applies to you.

(c) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.6645.

(d) Non-emergency 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions by 76 percent or more can demonstrate initial compliance with the formaldehyde emission limit by testing for THC instead of formaldehyde. The testing must be conducted according to the requirements in Table 4 of this subpart. The average reduction of emissions of THC determined from the performance test must be equal to or greater than 30 percent.

(e) The initial compliance demonstration required for existing non-emergency 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year must be conducted according to the following requirements:

(1) The compliance demonstration must consist of at least three test runs.

(2) Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.

(3) If you are demonstrating compliance with the CO concentration or CO percent reduction requirement, you must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.

(4) If you are demonstrating compliance with the THC percent reduction requirement, you must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.

(5) You must measure O_2 using one of the O_2 measurement methods specified in Table 4 of this subpart. Measurements to determine O_2 concentration must be made at the same time as the measurements for CO or THC concentration.

(6) If you are demonstrating compliance with the CO or THC percent reduction requirement, you must measure CO or THC emissions and O_2 emissions simultaneously at the inlet and outlet of the control device.

[69 FR 33506, June 15, 2004, as amended at 78 FR 6704, Jan. 30, 2013]

Continuous Compliance Requirements

§63.6635 How do I monitor and collect data to demonstrate continuous compliance?

(a) If you must comply with emission and operating limitations, you must monitor and collect data according to this section.

(b) Except for monitor malfunctions, associated repairs, required performance evaluations, and required quality assurance or control activities, you must monitor continuously at all times that the stationary RICE is operating. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

(c) You may not use data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities in data averages and calculations used to report emission or operating levels. You must, however, use all the valid data collected during all other periods.

[69 FR 33506, June 15, 2004, as amended at 76 FR 12867, Mar. 9, 2011]

§63.6640 How do I demonstrate continuous compliance with the emission limitations, operating limitations, and other requirements?

(a) You must demonstrate continuous compliance with each emission limitation, operating limitation, and other requirements in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you according to methods specified in Table 6 to this subpart.

The facility operates in compliance with the operating limitations in Table 2d according to methods in Table 6, including:

- Operate and maintain the RICE according to the manufacturer's emission-related operation and maintenance instructions, or
- Develop and follow a site maintenance plan that provides for operation and maintenance of the engine in a manner consistent with good air pollution control practice for minimizing emissions.

(b) You must report each instance in which you did not meet each emission limitation or operating limitation in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you. These instances are deviations from the emission and operating limitations in this subpart. These deviations must be reported according to the requirements in §63.6650. If you change your catalyst, you must reestablish the values of the operating parameters measured during the initial performance test. When you reestablish the values of your operating parameters, you must also conduct a performance test to demonstrate that you are meeting the required emission limitation applicable to your stationary RICE.

The facility will report each instance in which it did not meet the operation limitations (work practice standards).

(c) The annual compliance demonstration required for existing non-emergency 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year must be conducted according to the following requirements:

(1) The compliance demonstration must consist of at least one test run.

(2) Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.

(3) If you are demonstrating compliance with the CO concentration or CO percent reduction requirement, you must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.

(4) If you are demonstrating compliance with the THC percent reduction requirement, you must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.

(5) You must measure O_2 using one of the O_2 measurement methods specified in Table 4 of this subpart. Measurements to determine O_2 concentration must be made at the same time as the measurements for CO or THC concentration.

(6) If you are demonstrating compliance with the CO or THC percent reduction requirement, you must measure CO or THC emissions and O_2 emissions simultaneously at the inlet and outlet of the control device.

(7) If the results of the annual compliance demonstration show that the emissions exceed the levels specified in Table 6 of this subpart, the stationary RICE must be shut down as soon as safely possible, and appropriate corrective action must be taken (e.g., repairs, catalyst cleaning, catalyst replacement). The stationary RICE must be retested within 7 days of being restarted and the emissions must meet the levels specified in Table 6 of this subpart. If the retest shows that the emissions continue to exceed the specified levels, the stationary RICE must again be shut down as soon as safely possible, and the stationary RICE may not operate, except for purposes of startup and testing, until the owner/operator demonstrates through testing that the emissions do not exceed the levels specified in Table 6 of this subpart.

(d) For new, reconstructed, and rebuilt stationary RICE, deviations from the emission or operating limitations that occur during the first 200 hours of operation from engine startup (engine burn-in period) are not violations. Rebuilt stationary RICE means a stationary RICE that has been rebuilt as that term is defined in 40 CFR 94.11(a).

(e) You must also report each instance in which you did not meet the requirements in Table 8 to this subpart that apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing emergency stationary RICE, an existing limited use stationary RICE, or an existing stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart, except for the initial notification requirements: a new or reconstructed stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new or reconstructed emergency stationary RICE, or a new or reconstructed limited use stationary RICE.

The requirements below in (f)(1), (f)(2), (f)(2)(i), and (f)(4) are applicable to the emergency generator at the Pocatello plant.

(f) If you own or operate an emergency stationary RICE, you must operate the emergency stationary RICE according to the requirements in paragraphs (f)(1) through (4) of this section. In order for the engine to be considered an emergency stationary RICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (4) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (4) of this section, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary RICE in emergency situations.

(2) You may operate your emergency stationary RICE for any combination of the purposes specified in paragraphs (f)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraphs (f)(3) and (4) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary RICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year.

The Pocatello plant operates the emergency generator for less than 1 hr per month for maintenance and testing purposes. This equates to less than 12 hours/year of operation, in compliance with the 100 hr/yr threshold.

(ii) Emergency stationary RICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see §63.14), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.

(iii) Emergency stationary RICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

(3) Emergency stationary RICE located at major sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. The 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(4) Emergency stationary RICE located at area sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. Except as provided in paragraphs (f)(4)(i) and (ii) of this section, the 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

Great Western Malting acknowledges this condition but typically only runs the emergency generator for maintenance and testing.

(i) Prior to May 3, 2014, the 50 hours per year for non-emergency situations can be used for peak shaving or non-emergency demand response to generate income for a facility, or to otherwise supply power as part of a financial arrangement with another entity if the engine is operated as part of a peak shaving (load management program) with the local distribution system operator and the power is provided only to the facility itself or to support the local distribution system.

(ii) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator.

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

[69 FR 33506, June 15, 2004, as amended at 71 FR 20467, Apr. 20, 2006; 73 FR 3606, Jan. 18, 2008; 75 FR 9676, Mar. 3, 2010; 75 FR 51591, Aug. 20, 2010; 78 FR 6704, Jan. 30, 2013]

Notifications, Reports, and Records

§63.6645 What notifications must I submit and when?

(a) You must submit all of the notifications in §§63.7(b) and (c), 63.8(e), (f)(4) and (f)(6), 63.9(b) through (e), and (g) and (h) that apply to you by the dates specified if you own or operate any of the following;

(1) An existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

(2) An existing stationary RICE located at an area source of HAP emissions.

(3) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(4) A new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 HP located at a major source of HAP emissions.

(5) This requirement does not apply if you own or operate an existing stationary RICE less than 100 HP, an existing stationary emergency RICE, or an existing stationary RICE that is not subject to any numerical emission standards.

The notification requirements in 63.6645 do not apply to the existing RICE emergency generator at the Pocatello plant.

(b) As specified in §63.9(b)(2), if you start up your stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart, you must submit an Initial Notification not later than December 13, 2004.

(c) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions on or after August 16, 2004, you must submit an Initial Notification not later than 120 days after you become subject to this subpart.

(d) As specified in §63.9(b)(2), if you start up your stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart and you are required to submit an initial notification, you must submit an Initial Notification not later than July 16, 2008.

(e) If you start up your new or reconstructed stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions on or after March 18, 2008 and you are required to submit an initial notification, you must submit an Initial Notification not later than 120 days after you become subject to this subpart.

(f) If you are required to submit an Initial Notification but are otherwise not affected by the requirements of this subpart, in accordance with §63.6590(b), your notification should include the information in §63.9(b)(2)(i) through (v), and a statement that your stationary RICE has no additional requirements and explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary RICE if it has a site rating of more than 500 brake HP located at a major source of HAP emissions).

(g) If you are required to conduct a performance test, you must submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin as required in §63.7(b)(1).

(h) If you are required to conduct a performance test or other initial compliance demonstration as specified in Tables 4 and 5 to this subpart, you must submit a Notification of Compliance Status according to §63.9(h)(2)(ii).

(1) For each initial compliance demonstration required in Table 5 to this subpart that does not include a performance test, you must submit the Notification of Compliance Status before the close of business on the 30th day following the completion of the initial compliance demonstration.

(2) For each initial compliance demonstration required in Table 5 to this subpart that includes a performance test conducted according to the requirements in Table 3 to this subpart, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th day following the completion of the performance test according to §63.10(d)(2).

(i) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 1 or Tier 2 emission standards in Table 1 of 40 CFR 89.112 and subject to an enforceable state or local standard requiring engine replacement and you intend to meet management practices rather than emission limits, as specified in §63.6603(d), you must submit a notification by March 3, 2013, stating that you intend to use the provision in §63.6603(d) and identifying the state or local regulation that the engine is subject to.

[73 FR 3606, Jan. 18, 2008, as amended at 75 FR 9677, Mar. 3, 2010; 75 FR 51591, Aug. 20, 2010; 78 FR 6705, Jan. 30, 2013]

§63.6650 What reports must I submit and when?

(a) You must submit each report in Table 7 of this subpart that applies to you.

There are no reporting requirements in Table 7 that apply to existing emergency generators at area sources.

(b) Unless the Administrator has approved a different schedule for submission of reports under §63.10(a), you must submit each report by the date in Table 7 of this subpart and according to the requirements in paragraphs (b)(1) through (b)(9) of this section.

(1) For semiannual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.6595 and ending on June 30 or December 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in §63.6595.

(2) For semiannual Compliance reports, the first Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date follows the end of the first calendar half after the compliance date that is specified for your affected source in §63.6595.

(3) For semiannual Compliance reports, each subsequent Compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) For semiannual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(5) For each stationary RICE that is subject to permitting regulations pursuant to 40 CFR part 70 or 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6 (a)(3)(iii)(A), you may submit the first and subsequent Compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (b)(4) of this section.

(6) For annual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.6595 and ending on December 31.

(7) For annual Compliance reports, the first Compliance report must be postmarked or delivered no later than January 31 following the end of the first calendar year after the compliance date that is specified for your affected source in §63.6595.

(8) For annual Compliance reports, each subsequent Compliance report must cover the annual reporting period from January 1 through December 31.

(9) For annual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than January 31.

(c) The Compliance report must contain the information in paragraphs (c)(1) through (6) of this section.

(1) Company name and address.

(2) Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report.

(3) Date of report and beginning and ending dates of the reporting period.

(4) If you had a malfunction during the reporting period, the compliance report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with §63.6605(b), including actions taken to correct a malfunction.

(5) If there are no deviations from any emission or operating limitations that apply to you, a statement that there were no deviations from the emission or operating limitations during the reporting period.

(6) If there were no periods during which the continuous monitoring system (CMS), including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), a statement that there were no periods during which the CMS was out-of-control during the reporting period.

(d) For each deviation from an emission or operating limitation that occurs for a stationary RICE where you are not using a CMS to comply with the emission or operating limitations in this subpart, the Compliance report must contain the information in paragraphs (c)(1) through (4) of this section and the information in paragraphs (d)(1) and (2) of this section.

(1) The total operating time of the stationary RICE at which the deviation occurred during the reporting period.

(2) Information on the number, duration, and cause of deviations (including unknown cause, if applicable), as applicable, and the corrective action taken.

(e) For each deviation from an emission or operating limitation occurring for a stationary RICE where you are using a CMS to comply with the emission and operating limitations in this subpart, you must include information in paragraphs (c)(1) through (4) and (e)(1) through (12) of this section.

(1) The date and time that each malfunction started and stopped.

(2) The date, time, and duration that each CMS was inoperative, except for zero (low-level) and high-level checks.

(3) The date, time, and duration that each CMS was out-of-control, including the information in §63.8(c)(8).

(4) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of malfunction or during another period.

(5) A summary of the total duration of the deviation during the reporting period, and the total duration as a percent of the total source operating time during that reporting period.

(6) A breakdown of the total duration of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of CMS downtime during the reporting period, and the total duration of CMS downtime as a percent of the total operating time of the stationary RICE at which the CMS downtime occurred during that reporting period.

(8) An identification of each parameter and pollutant (CO or formaldehyde) that was monitored at the stationary RICE.

(9) A brief description of the stationary RICE.

(10) A brief description of the CMS.

(11) The date of the latest CMS certification or audit.

(12) A description of any changes in CMS, processes, or controls since the last reporting period.

(f) Each affected source that has obtained a title V operating permit pursuant to 40 CFR part 70 or 71 must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6 (a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a Compliance report pursuant to Table 7 of this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the Compliance report includes all required information concerning deviations from any emission or operating limitation in this subpart, submission of the Compliance report shall be deemed to satisfy any obligation to report the same deviations in the semiannual monitoring report. However, submission of a Compliance report shall not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.

(g) If you are operating as a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must submit an annual report according to Table 7 of this subpart by the date specified unless the Administrator has approved a different schedule, according to the information described in paragraphs (b)(1) through (b)(5) of this section. You must report the data specified in (g)(1) through (g)(3) of this section.

(1) Fuel flow rate of each fuel and the heating values that were used in your calculations. You must also demonstrate that the percentage of heat input provided by landfill gas or digester gas is equivalent to 10 percent or more of the total fuel consumption on an annual basis.

(2) The operating limits provided in your federally enforceable permit, and any deviations from these limits.

(3) Any problems or errors suspected with the meters.

(h) If you own or operate an emergency stationary RICE with a site rating of more than 100 brake HP that operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii) or that operates for the purpose specified in §63.6640(f)(4)(ii), you must submit an annual report according to the requirements in paragraphs (h)(1) through (3) of this section.

(1) The report must contain the following information:

(i) Company name and address where the engine is located.

(ii) Date of the report and beginning and ending dates of the reporting period.

(iii) Engine site rating and model year.

(iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(v) Hours operated for the purposes specified in §63.6640(f)(2)(ii) and (iii), including the date, start time, and end time for engine operation for the purposes specified in §63.6640(f)(2)(ii) and (iii).

(vi) Number of hours the engine is contractually obligated to be available for the purposes specified in §63.6640(f)(2)(ii) and (iii).

(vii) Hours spent for operation for the purpose specified in §63.6640(f)(4)(ii), including the date, start time, and end time for engine operation for the purposes specified in §63.6640(f)(4)(ii). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

(viii) If there were no deviations from the fuel requirements in §63.6604 that apply to the engine (if any), a statement that there were no deviations from the fuel requirements during the reporting period.

(ix) If there were deviations from the fuel requirements in §63.6604 that apply to the engine (if any), information on the number, duration, and cause of deviations, and the corrective action taken.

(2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

(3) The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in §63.13.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9677, Mar. 3, 2010; 78 FR 6705, Jan. 30, 2013]

§63.6655 What records must I keep?

(a) If you must comply with the emission and operating limitations, you must keep the records described in paragraphs (a)(1) through (a)(5), (b)(1) through (b)(3) and (c) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status that you submitted, according to the requirement in §63.10(b)(2)(xiv).

(2) Records of the occurrence and duration of each malfunction of operation (*i.e.,* process equipment) or the air pollution control and monitoring equipment.

(3) Records of performance tests and performance evaluations as required in §63.10(b)(2)(viii).

(4) Records of all required maintenance performed on the air pollution control and monitoring equipment.

(5) Records of actions taken during periods of malfunction to minimize emissions in accordance with §63.6605(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(b) For each CEMS or CPMS, you must keep the records listed in paragraphs (b)(1) through (3) of this section.

(1) Records described in §63.10(b)(2)(vi) through (xi).

(2) Previous (*i.e.,* superseded) versions of the performance evaluation plan as required in §63.8(d)(3).

(3) Requests for alternatives to the relative accuracy test for CEMS or CPMS as required in §63.8(f)(6)(i), if applicable.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must keep the records of your daily fuel usage monitors.

(d) You must keep the records required in Table 6 of this subpart to show continuous compliance with each emission or operating limitation that applies to you.

(e) You must keep records of the maintenance conducted on the stationary RICE in order to demonstrate that you operated and maintained the stationary RICE and after-treatment control device (if any) according to your own maintenance plan if you own or operate any of the following stationary RICE;

(1) An existing stationary RICE with a site rating of less than 100 brake HP located at a major source of HAP emissions.

(2) An existing stationary emergency RICE.

Great Western Malting keeps maintenance records for the emergency generator.

(3) An existing stationary RICE located at an area source of HAP emissions subject to management practices as shown in Table 2d to this subpart.

(f) If you own or operate any of the stationary RICE in paragraphs (f)(1) through (2) of this section, you must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The owner or operator must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation. If the engine is used for the purposes specified in §63.6640(f)(2)(ii) or (iii) or §63.6640(f)(4)(ii), the owner or operator must keep records of the notification of the emergency situation, and the date, start time, and end time of engine operation for these purposes.

(1) An existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions that does not meet the standards applicable to non-emergency engines.

(2) An existing emergency stationary RICE located at an area source of HAP emissions that does not meet the standards applicable to non-emergency engines.

Records on the hours of operation for the emergency generator are kept.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9678, Mar. 3, 2010; 75 FR 51592, Aug. 20, 2010; 78 FR 6706, Jan. 30, 2013]

§63.6660 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review according to §63.10(b)(1).

(b) As specified in §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1).

Records on the emergency generator are kept at the facility.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9678, Mar. 3, 2010]

Other Requirements and Information

§63.6665 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§63.1 through 63.15 apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with any of the requirements of the General Provisions specified in Table 8: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing stationary RICE that combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, an existing emergency stationary RICE, or an existing limited use stationary RICE. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in the General Provisions specified in Table 8 except for the initial notification requirements: A new stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new emergency stationary RICE, or a new limited use stationary RICE.

[75 FR 9678, Mar. 3, 2010]

§63.6670 Who implements and enforces this subpart?

(a) This subpart is implemented and enforced by the U.S. EPA, or a delegated authority such as your State, local, or tribal agency. If the U.S. EPA Administrator has delegated authority to your State, local, or tribal agency, then that agency (as well as the U.S. EPA) has the authority to implement and enforce this subpart. You should contact your U.S. EPA Regional Office to find out whether this subpart is delegated to your State, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under 40 CFR part 63, subpart E, the authorities contained in paragraph (c) of this section are retained by the Administrator of the U.S. EPA and are not transferred to the State, local, or tribal agency.

(c) The authorities that will not be delegated to State, local, or tribal agencies are:

(1) Approval of alternatives to the non-opacity emission limitations and operating limitations in §63.6600 under §63.6(g).

(2) Approval of major alternatives to test methods under §63.7(e)(2)(ii) and (f) and as defined in §63.90.

(3) Approval of major alternatives to monitoring under §63.8(f) and as defined in §63.90.

(4) Approval of major alternatives to recordkeeping and reporting under §63.10(f) and as defined in §63.90.

(5) Approval of a performance test which was conducted prior to the effective date of the rule, as specified in §63.6610(b).

§63.6675 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act (CAA); in 40 CFR 63.2, the General Provisions of this part; and in this section as follows:

Alaska Railbelt Grid means the service areas of the six regulated public utilities that extend from Fairbanks to Anchorage and the Kenai Peninsula. These utilities are Golden Valley Electric Association; Chugach Electric Association; Matanuska Electric Association; Homer Electric Association; Anchorage Municipal Light & Power; and the City of Seward Electric System.

Area source means any stationary source of HAP that is not a major source as defined in part 63.

Associated equipment as used in this subpart and as referred to in section 112(n)(4) of the CAA, means equipment associated with an oil or natural gas exploration or production well, and includes all equipment from the well bore to the point of custody transfer, except glycol dehydration units, storage vessels with potential for flash emissions, combustion turbines, and stationary RICE.

Backup power for renewable energy means an engine that provides backup power to a facility that generates electricity from renewable energy resources, as that term is defined in Alaska Statute 42.45.045(l)(5) (incorporated by reference, see §63.14).

Black start engine means an engine whose only purpose is to start up a combustion turbine.

CAA means the Clean Air Act (42 U.S.C. 7401 *et seq.,* as amended by Public Law 101-549, 104 Stat. 2399).

Commercial emergency stationary RICE means an emergency stationary RICE used in commercial establishments such as office buildings, hotels, stores, telecommunications facilities, restaurants, financial institutions such as banks, doctor's offices, and sports and performing arts facilities.

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Custody transfer means the transfer of hydrocarbon liquids or natural gas: After processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation. For the purposes of this subpart, the point at which such liquids or natural gas enters a natural gas processing plant is a point of custody transfer.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart, including but not limited to any emission limitation or operating limitation;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limitation or operating limitation in this subpart during malfunction, regardless or whether or not such failure is permitted by this subpart.

(4) Fails to satisfy the general duty to minimize emissions established by §63.6(e)(1)(i).

Diesel engine means any stationary RICE in which a high boiling point liquid fuel injected into the combustion chamber ignites when the air charge has been compressed to a temperature sufficiently high for auto-ignition. This process is also known as compression ignition.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is fuel oil number 2. Diesel fuel also includes any non-distillate fuel with comparable physical and chemical properties (*e.g.* biodiesel) that is suitable for use in compression ignition engines.

Digester gas means any gaseous by-product of wastewater treatment typically formed through the anaerobic decomposition of organic waste materials and composed principally of methane and CO_2.

Dual-fuel engine means any stationary RICE in which a liquid fuel (typically diesel fuel) is used for compression ignition and gaseous fuel (typically natural gas) is used as the primary fuel.

Emergency stationary RICE means any stationary reciprocating internal combustion engine that meets all of the criteria in paragraphs (1) through (3) of this definition. All emergency stationary RICE must comply with the requirements specified in §63.6640(f) in order to be considered emergency stationary RICE. If the engine does not comply with the requirements specified in §63.6640(f), then it is not considered to be an emergency stationary RICE under this subpart.

(1) The stationary RICE is operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary RICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary RICE used to pump water in the case of fire or flood, etc.

(2) The stationary RICE is operated under limited circumstances for situations not included in paragraph (1) of this definition, as specified in §63.6640(f).

The emergency generator at the plant meets these definitions.

(3) The stationary RICE operates as part of a financial arrangement with another entity in situations not included in paragraph (1) of this definition only as allowed in §63.6640(f)(2)(ii) or (iii) and §63.6640(f)(4)(i) or (ii).

Engine startup means the time from initial start until applied load and engine and associated equipment reaches steady state or normal operation. For stationary engine with catalytic controls, engine startup means the time from initial start until applied load and engine and associated equipment, including the catalyst, reaches steady state or normal operation.

Four-stroke engine means any type of engine which completes the power cycle in two crankshaft revolutions, with intake and compression strokes in the first revolution and power and exhaust strokes in the second revolution.

Gaseous fuel means a material used for combustion which is in the gaseous state at standard atmospheric temperature and pressure conditions.

Gasoline means any fuel sold in any State for use in motor vehicles and motor vehicle engines, or nonroad or stationary engines, and commonly or commercially known or sold as gasoline.

Glycol dehydration unit means a device in which a liquid glycol (including, but not limited to, ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water in a contact tower or absorption column (absorber). The glycol contacts and absorbs water vapor and other gas stream constituents from the natural gas and becomes "rich" glycol. This glycol is then regenerated in the glycol dehydration unit reboiler. The "lean" glycol is then recycled.

Hazardous air pollutants (HAP) means any air pollutants listed in or pursuant to section 112(b) of the CAA.

Institutional emergency stationary RICE means an emergency stationary RICE used in institutional establishments such as medical centers, nursing homes, research centers, institutions of higher education, correctional facilities, elementary and secondary schools, libraries, religious establishments, police stations, and fire stations.

ISO standard day conditions means 288 degrees Kelvin (15 degrees Celsius), 60 percent relative humidity and 101.3 kilopascals pressure.

Landfill gas means a gaseous by-product of the land application of municipal refuse typically formed through the anaerobic decomposition of waste materials and composed principally of methane and CO_2.

Lean burn engine means any two-stroke or four-stroke spark ignited engine that does not meet the definition of a rich burn engine.

Limited use stationary RICE means any stationary RICE that operates less than 100 hours per year.

Liquefied petroleum gas means any liquefied hydrocarbon gas obtained as a by-product in petroleum refining of natural gas production.

Liquid fuel means any fuel in liquid form at standard temperature and pressure, including but not limited to diesel, residual/crude oil, kerosene/naphtha (jet fuel), and gasoline.

Major Source, as used in this subpart, shall have the same meaning as in §63.2, except that:

(1) Emissions from any oil or gas exploration or production well (with its associated equipment (as defined in this section)) and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units, to determine whether such emission points or stations are major sources, even when emission points are in a contiguous area or under common control;

(2) For oil and gas production facilities, emissions from processes, operations, or equipment that are not part of the same oil and gas production facility, as defined in §63.1271 of subpart HHH of this part, shall not be aggregated;

(3) For production field facilities, only HAP emissions from glycol dehydration units, storage vessel with the potential for flash emissions, combustion turbines and reciprocating internal combustion engines shall be aggregated for a major source determination; and

(4) Emissions from processes, operations, and equipment that are not part of the same natural gas transmission and storage facility, as defined in §63.1271 of subpart HHH of this part, shall not be aggregated.

Malfunction means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner which causes, or has the potential to cause, the emission limitations in an applicable standard to be exceeded. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Natural gas means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the Earth's surface, of which the principal constituent is methane. Natural gas may be field or pipeline quality.

Non-selective catalytic reduction (NSCR) means an add-on catalytic nitrogen oxides (NO_x) control device for rich burn engines that, in a two-step reaction, promotes the conversion of excess oxygen, NO_x, CO, and volatile organic compounds (VOC) into CO_2, nitrogen, and water.

Oil and gas production facility as used in this subpart means any grouping of equipment where hydrocarbon liquids are processed, upgraded (*i.e.,* remove impurities or other constituents to meet contract specifications), or stored prior to the point of custody transfer; or where natural gas is processed, upgraded, or stored prior to entering the natural gas transmission and storage source category. For purposes of a major source determination, facility (including a building, structure, or installation) means oil and natural gas production and processing equipment that is located within the boundaries of an individual surface site as defined in this section. Equipment that is part of a facility will typically be located within close proximity to other equipment located at the same facility. Pieces of production equipment or groupings of equipment located on different oil and gas leases, mineral fee tracts, lease tracts, subsurface or surface unit areas, surface fee tracts, surface lease tracts, or separate surface sites, whether or not connected by a road, waterway, power line or pipeline, shall not be considered part of the same facility. Examples of facilities in the oil and natural gas production source category include, but are not limited to, well sites, satellite tank batteries, central tank batteries, a compressor station that transports natural gas to a natural gas processing plant, and natural gas processing plants.

Oxidation catalyst means an add-on catalytic control device that controls CO and VOC by oxidation.

Peaking unit or engine means any standby engine intended for use during periods of high demand that are not emergencies.

Percent load means the fractional power of an engine compared to its maximum manufacturer's design capacity at engine site conditions. Percent load may range between 0 percent to above 100 percent.

Potential to emit means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the stationary source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. For oil and natural gas production facilities subject to subpart HH of this part, the potential to emit provisions in §63.760(a) may be used. For natural gas transmission and storage facilities subject to subpart HHH of this part, the maximum annual facility gas throughput for storage facilities may be determined according to §63.1270(a)(1) and the maximum annual throughput for transmission facilities may be determined according to §63.1270(a)(2).

Production field facility means those oil and gas production facilities located prior to the point of custody transfer.

Production well means any hole drilled in the earth from which crude oil, condensate, or field natural gas is extracted.

Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure C_3H_8.

Remote stationary RICE means stationary RICE meeting any of the following criteria:

(1) Stationary RICE located in an offshore area that is beyond the line of ordinary low water along that portion of the coast of the United States that is in direct contact with the open seas and beyond the line marking the seaward limit of inland waters.

(2) Stationary RICE located on a pipeline segment that meets both of the criteria in paragraphs (2)(i) and (ii) of this definition.

(i) A pipeline segment with 10 or fewer buildings intended for human occupancy and no buildings with four or more stories within 220 yards (200 meters) on either side of the centerline of any continuous 1-mile (1.6 kilometers) length of pipeline. Each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy.

(ii) The pipeline segment does not lie within 100 yards (91 meters) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. The days and weeks need not be consecutive. The building or area is considered occupied for a full day if it is occupied for any portion of the day.

(iii) For purposes of this paragraph (2), the term pipeline segment means all parts of those physical facilities through which gas moves in transportation, including but not limited to pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies. Stationary RICE located within 50 yards (46 meters) of the pipeline segment providing power for equipment on a pipeline segment are part of the pipeline segment. Transportation of gas means the gathering, transmission, or distribution of gas by pipeline, or the storage of gas. A building is intended for human occupancy if its primary use is for a purpose involving the presence of humans.

(3) Stationary RICE that are not located on gas pipelines and that have 5 or fewer buildings intended for human occupancy and no buildings with four or more stories within a 0.25 mile radius around the engine. A building is intended for human occupancy if its primary use is for a purpose involving the presence of humans.

Residential emergency stationary RICE means an emergency stationary RICE used in residential establishments such as homes or apartment buildings.

Responsible official means responsible official as defined in 40 CFR 70.2.

Rich burn engine means any four-stroke spark ignited engine where the manufacturer's recommended operating air/fuel ratio divided by the stoichiometric air/fuel ratio at full load conditions is less than or equal to 1.1. Engines originally manufactured as rich burn engines, but modified prior to December 19, 2002 with passive emission control technology for NO_x (such as pre-combustion chambers) will be considered lean burn engines. Also, existing engines where there are no manufacturer's recommendations regarding air/fuel ratio will be considered a rich burn engine if the excess oxygen content of the exhaust at full load conditions is less than or equal to 2 percent.

Site-rated HP means the maximum manufacturer's design capacity at engine site conditions.

Spark ignition means relating to either: A gasoline-fueled engine; or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

Stationary reciprocating internal combustion engine (RICE) means any reciprocating internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

Stationary RICE test cell/stand means an engine test cell/stand, as defined in subpart PPPPP of this part, that tests stationary RICE.

Stoichiometric means the theoretical air-to-fuel ratio required for complete combustion.

Storage vessel with the potential for flash emissions means any storage vessel that contains a hydrocarbon liquid with a stock tank gas-to-oil ratio equal to or greater than 0.31 cubic meters per liter and an American Petroleum Institute gravity equal to or greater than 40 degrees and an actual annual average hydrocarbon liquid throughput equal to or greater than 79,500 liters per day. Flash emissions occur when dissolved hydrocarbons in the fluid evolve from solution when the fluid pressure is reduced.

Subpart means 40 CFR part 63, subpart ZZZZ.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Two-stroke engine means a type of engine which completes the power cycle in single crankshaft revolution by combining the intake and compression operations into one stroke and the power and exhaust operations into a second stroke. This system requires auxiliary scavenging and inherently runs lean of stoichiometric.

[69 FR 33506, June 15, 2004, as amended at 71 FR 20467, Apr. 20, 2006; 73 FR 3607, Jan. 18, 2008; 75 FR 9679, Mar. 3, 2010; 75 FR 51592, Aug. 20, 2010; 76 FR 12867, Mar. 9, 2011; 78 FR 6706, Jan. 30, 2013]

Table 1a to Subpart ZZZZ of Part 63—Emission Limitations for Existing, New, and Reconstructed Spark Ignition, 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600 and 63.6640, you must comply with the following emission limitations at 100 percent load plus or minus 10 percent for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions:

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
1. 4SRB stationary RICE	a. Reduce formaldehyde emissions by 76 percent or more. If you commenced construction or reconstruction between	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe

	December 19, 2002 and June 15, 2004, you may reduce formaldehyde emissions by 75 percent or more until June 15, 2007 or	loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[1]
	b. Limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O_2	

[1] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[75 FR 9679, Mar. 3, 2010, as amended at 75 FR 51592, Aug. 20, 2010]

Table 1b to Subpart ZZZZ of Part 63—Operating Limitations for Existing, New, and Reconstructed SI 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600, 63.6603, 63.6630 and 63.6640, you must comply with the following operating limitations for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions:

For each . . .	You must meet the following operating limitation, except during periods of startup . . .
1. existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and using NSCR; or existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O_2 and using NSCR;	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst measured during the initial performance test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 750 °F and less than or equal to 1250 °F.[1]
2. existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and not using NSCR; or	Comply with any operating limitations approved by the Administrator.
existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O_2 and not using NSCR.	

[1]Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(f) for a different temperature range.

[78 FR 6706, Jan. 30, 2013]

Table 2a to Subpart ZZZZ of Part 63—Emission Limitations for New and Reconstructed 2SLB and Compression Ignition Stationary RICE >500 HP and New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600 and 63.6640, you must comply with the following emission limitations for new and reconstructed lean burn and new and reconstructed compression ignition stationary RICE at 100 percent load plus or minus 10 percent:

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
1. 2SLB stationary RICE	a. Reduce CO emissions by 58 percent or more; or b. Limit concentration of formaldehyde in the stationary RICE exhaust to 12 ppmvd or less at 15 percent O_2. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may limit concentration of formaldehyde to 17 ppmvd or less at 15 percent O_2 until June 15, 2007	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[1]
2. 4SLB stationary RICE	a. Reduce CO emissions by 93 percent or more; or	
	b. Limit concentration of formaldehyde in the stationary RICE exhaust to 14 ppmvd or less at 15 percent O_2	
3. CI stationary RICE	a. Reduce CO emissions by 70 percent or more; or	
	b. Limit concentration of formaldehyde in the stationary RICE exhaust to 580 ppbvd or less at 15 percent O_2	

[1]Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[75 FR 9680, Mar. 3, 2010]

Table 2b to Subpart ZZZZ of Part 63—Operating Limitations for New and Reconstructed 2SLB and CI Stationary RICE >500 HP Located at a Major Source of HAP Emissions, New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions, Existing CI Stationary RICE >500 HP

As stated in §§63.6600, 63.6601, 63.6603, 63.6630, and 63.6640, you must comply with the following operating limitations for new and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions; new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions; and existing CI stationary RICE >500 HP:

For each . . .	You must meet the following operating limitation, except during periods of startup . . .

1. New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to reduce CO emissions and using an oxidation catalyst; and New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and using an oxidation catalyst.	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst that was measured during the initial performance test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F.[1]
2. Existing CI stationary RICE >500 HP complying with the requirement to limit or reduce the concentration of CO in the stationary RICE exhaust and using an oxidation catalyst	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water from the pressure drop across the catalyst that was measured during the initial performance test; and
	b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F.[1]
3. New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to reduce CO emissions and not using an oxidation catalyst; and	Comply with any operating limitations approved by the Administrator.
New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and not using an oxidation catalyst; and	
existing CI stationary RICE >500 HP complying with the requirement to limit or reduce the concentration of CO in the stationary RICE exhaust and not using an oxidation catalyst.	

[1]Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(f) for a different temperature range.

[78 FR 6707, Jan. 30, 2013]

Table 2c to Subpart ZZZZ of Part 63—Requirements for Existing Compression Ignition Stationary RICE Located at a Major Source of HAP Emissions and Existing Spark Ignition Stationary RICE ≤500 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600, 63.6602, and 63.6640, you must comply with the following requirements for existing compression ignition stationary RICE located at a major source of HAP emissions and existing spark ignition stationary RICE ≤500 HP located at a major source of HAP emissions:

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Emergency stationary CI RICE and black start stationary CI RICE[1]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first.[2] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[3]
2. Non-Emergency, non-black start stationary CI RICE <100 HP	a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first.[2] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
3. Non-Emergency, non-black start CI stationary RICE 100≤HP≤300 HP	Limit concentration of CO in the stationary RICE exhaust to 230 ppmvd or less at 15 percent O_2.	
4. Non-Emergency, non-black start CI stationary RICE 300<HP≤500	a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd or less at 15 percent O_2; or b. Reduce CO emissions by 70 percent or more.	
5. Non-Emergency, non-black start stationary CI RICE >500 HP	a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd or less at 15 percent O_2; or b. Reduce CO emissions by	

	70 percent or more.	
6. Emergency stationary SI RICE and black start stationary SI RICE.[1]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[2] b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
7. Non-Emergency, non-black start stationary SI RICE <100 HP that are not 2SLB stationary RICE	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[2] b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary;	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
8. Non-Emergency, non-black start 2SLB stationary SI RICE <100 HP	a. Change oil and filter every 4,320 hours of operation or annually, whichever comes first;[2] b. Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first, and replace as necessary;	
	c. Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
9. Non-emergency, non-black start 2SLB stationary RICE 100≤HP≤500	Limit concentration of CO in the stationary RICE exhaust to 225 ppmvd or less at 15 percent O_2.	
10. Non-emergency, non-black start 4SLB stationary RICE 100≤HP≤500	Limit concentration of CO in the stationary RICE exhaust to 47 ppmvd or less	

	at 15 percent O_2.	
11. Non-emergency, non-black start 4SRB stationary RICE 100≤HP≤500	Limit concentration of formaldehyde in the stationary RICE exhaust to 10.3 ppmvd or less at 15 percent O_2.	
12. Non-emergency, non-black start stationary RICE 100≤HP≤500 which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	Limit concentration of CO in the stationary RICE exhaust to 177 ppmvd or less at 15 percent O_2.	

[1]If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements on the schedule required in Table 2c of this subpart, or if performing the work practice on the required schedule would otherwise pose an unacceptable risk under federal, state, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under federal, state, or local law has abated. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under federal, state, or local law has abated. Sources must report any failure to perform the work practice on the schedule required and the federal, state or local law under which the risk was deemed unacceptable.

[2]Sources have the option to utilize an oil analysis program as described in §63.6625(i) or (j) in order to extend the specified oil change requirement in Table 2c of this subpart.

[3]Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[78 FR 6708, Jan. 30, 2013, as amended at 78 FR 14457, Mar. 6, 2013]

Table 2d to Subpart ZZZZ of Part 63—Requirements for Existing Stationary RICE Located at Area Sources of HAP Emissions

As stated in §§63.6603 and 63.6640, you must comply with the following requirements for existing stationary RICE located at area sources of HAP emissions:

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Non-Emergency, non-black start CI stationary RICE ≤300 HP	a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first;[1] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.

	operation or annually, whichever comes first, and replace as necessary.	
2. Non-Emergency, non-black start CI stationary RICE 300<HP≤500	a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more.	
3. Non-Emergency, non-black start CI stationary RICE >500 HP	a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more.	
4. Emergency stationary CI RICE and black start stationary CI RICE.[2]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[1]	Maintenance on the emergency generator meets these requirements.
	b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; and	Maintenance on the emergency generator meets these requirements.
	c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	Maintenance on the emergency generator meets these requirements.
5. Emergency stationary SI RICE; black start stationary SI RICE; non-emergency, non-black start 4SLB stationary RICE >500 HP that operate 24 hours or less per calendar year; non-emergency, non-black start 4SRB stationary RICE >500 HP that operate 24 hours or less per calendar year.[2]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[1]; b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; and c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	
6. Non-emergency, non-black start 2SLB stationary RICE	a. Change oil and filter every 4,320 hours of	

	operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace as necessary.	
7. Non-emergency, non-black start 4SLB stationary RICE ≤500 HP	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	
8. Non-emergency, non-black start 4SLB remote stationary RICE >500 HP	a. Change oil and filter every 2,160 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 2,160 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 2,160 hours of operation or annually, whichever comes first, and replace as necessary.	
9. Non-emergency, non-black start 4SLB stationary RICE >500 HP that are not remote stationary RICE and that operate more than 24 hours per calendar year	Install an oxidation catalyst to reduce HAP emissions from the stationary RICE.	
10. Non-emergency, non-black start 4SRB	a. Change oil and filter	

stationary RICE ≤500 HP	every 1,440 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	
11. Non-emergency, non-black start 4SRB remote stationary RICE >500 HP	a. Change oil and filter every 2,160 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 2,160 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 2,160 hours of operation or annually, whichever comes first, and replace as necessary.	
12. Non-emergency, non-black start 4SRB stationary RICE >500 HP that are not remote stationary RICE and that operate more than 24 hours per calendar year	Install NSCR to reduce HAP emissions from the stationary RICE.	
13. Non-emergency, non-black start stationary RICE which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1] b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	

[1]Sources have the option to utilize an oil analysis program as described in §63.6625(i) or (j) in order to extend the specified oil change requirement in Table 2d of this subpart.

[2]If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the management practice requirements on the schedule required in Table 2d of this subpart, or if performing the management practice on the required schedule would otherwise pose an unacceptable risk under federal, state, or local law, the management practice can be delayed until the emergency is over or the unacceptable risk under federal, state, or local law has abated. The management practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under federal, state, or local law has abated. Sources must report any failure to perform the management practice on the schedule required and the federal, state or local law under which the risk was deemed unacceptable.

[78 FR 6709, Jan. 30, 2013]

Table 3 to Subpart ZZZZ of Part 63—Subsequent Performance Tests

As stated in §§63.6615 and 63.6620, you must comply with the following subsequent performance test requirements:

For each . . .	Complying with the requirement to . . .	You must . . .
1. New or reconstructed 2SLB stationary RICE >500 HP located at major sources; new or reconstructed 4SLB stationary RICE ≥250 HP located at major sources; and new or reconstructed CI stationary RICE >500 HP located at major sources	Reduce CO emissions and not using a CEMS	Conduct subsequent performance tests semiannually.[1]
2. 4SRB stationary RICE ≥5,000 HP located at major sources	Reduce formaldehyde emissions	Conduct subsequent performance tests semiannually.[1]
3. Stationary RICE >500 HP located at major sources and new or reconstructed 4SLB stationary RICE 250≤HP≤500 located at major sources	Limit the concentration of formaldehyde in the stationary RICE exhaust	Conduct subsequent performance tests semiannually.[1]
4. Existing non-emergency, non-black start CI stationary RICE >500 HP that are not limited use stationary RICE	Limit or reduce CO emissions and not using a CEMS	Conduct subsequent performance tests every 8,760 hours or 3 years, whichever comes first.
5. Existing non-emergency, non-black start CI stationary RICE >500 HP that are limited use stationary RICE	Limit or reduce CO emissions and not using a CEMS	Conduct subsequent performance tests every 8,760 hours or 5 years, whichever comes first.

[1]After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

[78 FR 6711, Jan. 30, 2013]

Table 4 to Subpart ZZZZ of Part 63—Requirements for Performance Tests

As stated in §§63.6610, 63.6611, 63.6620, and 63.6640, you must comply with the following requirements for performance tests for stationary RICE:

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
1. 2SLB, 4SLB, and CI stationary RICE	a. reduce CO emissions	i. Select the sampling port location and the number/location of traverse points at the inlet and outlet of the control device; and		(a) For CO and O_2 measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line (`3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A-1, the duct may be sampled at `3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A-4.
		ii. Measure the O_2 at the inlet and outlet of the control device; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A-2, or ASTM Method D6522-00 (Reapproved 2005)[ac] (heated probe not necessary)	(b) Measurements to determine O_2 must be made at the same time as the measurements for CO concentration.
		iii. Measure the CO at the inlet and the outlet of the control device	(1) ASTM D6522-00 (Reapproved 2005)[abc] (heated probe not necessary) or Method 10 of 40 CFR part 60, appendix A-4	(c) The CO concentration must be at 15 percent O_2, dry basis.
2. 4SRB stationary RICE	a. reduce formaldehyde emissions	i. Select the sampling port location and the number/location of traverse points at the inlet and outlet of the control device; and		(a) For formaldehyde, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3

				traverse points located at 16.7, 50.0, and 83.3% of the measurement line (`3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A, the duct may be sampled at `3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A.
		ii. Measure O_2at the inlet and outlet of the control device; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A-2, or ASTM Method D6522-00 (Reapproved 2005)[a] (heated probe not necessary)	(a) Measurements to determine O_2 concentration must be made at the same time as the measurements for formaldehyde or THC concentration.
		iii. Measure moisture content at the inlet and outlet of the control device; and	(1) Method 4 of 40 CFR part 60, appendix A-3, or Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03[a]	(a) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde or THC concentration.
		iv. If demonstrating compliance with the formaldehyde percent reduction requirement, measure formalde-hyde at the inlet and the outlet of the control device	(1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348-03[a], provided in ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130	(a) Formaldehyde concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
		v. If demonstrating compliance with the THC percent reduction requirement, measure THC at the inlet and the outlet of the control device	(1) Method 25A, reported as propane, of 40 CFR part 60, appendix A-7	(a) THC concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
3. Stationary RICE	a. limit the concentration of formaldehyde or CO in the	i. Select the sampling port location and the number/location of traverse points at the		(a) For formaldehyde, CO, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single

	stationary RICE exhaust	exhaust of the stationary RICE; and		point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line (`3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A, the duct may be sampled at `3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A. If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2concentration of the stationary RICE exhaust at the sampling port location; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A-2, or ASTM Method D6522-00 (Reapproved 2005)[a] (heated probe not necessary)	(a) Measurements to determine O_2 concentration must be made at the same time and location as the measurements for formaldehyde or CO concentration.
		iii. Measure moisture content of the station-ary RICE exhaust at the sampling port location; and	(1) Method 4 of 40 CFR part 60, appendix A-3, or Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03[a]	(a) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde or CO concentration.
		iv. Measure formaldehyde at the exhaust of the stationary RICE; or	(1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348-03[a], provided in ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130	(a) Formaldehyde concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
		v. measure CO at the exhaust of the stationary RICE	(1) Method 10 of 40 CFR part 60, appendix A-4, ASTM Method D6522-00 (2005)[ac], Method 320 of 40 CFR	(a) CO concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

			part 63, appendix A, or ASTM D6348-03[a]	

[a]You may also use Methods 3A and 10 as options to ASTM-D6522-00 (2005). You may obtain a copy of ASTM-D6522-00 (2005) from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428-2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.

[b]You may obtain a copy of ASTM-D6348-03 from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428-2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.

[79 FR 11290, Feb. 27, 2014]

Table 5 to Subpart ZZZZ of Part 63—Initial Compliance With Emission Limitations, Operating Limitations, and Other Requirements

As stated in §§63.6612, 63.6625 and 63.6630, you must initially comply with the emission and operating limitations as required by the following:

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Reduce CO emissions and using oxidation catalyst, and using a CPMS	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
2. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Limit the concentration of CO, using oxidation catalyst, and using a CPMS	i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed	a. Reduce CO emissions and not using oxidation	i. The average reduction of emissions of CO determined from the initial performance test achieves the required

non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	catalyst	CO percent reduction; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.
4. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Limit the concentration of CO, and not using oxidation catalyst	i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
5. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Reduce CO emissions, and using a CEMS	i. You have installed a CEMS to continuously monitor CO and either O_2 or CO_2 at both the inlet and outlet of the oxidation catalyst according to the requirements in §63.6625(a); and ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and
		iii. The average reduction of CO calculated using §63.6620 equals or exceeds the required percent reduction. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average percent reduction achieved during the 4-hour period.
6. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Limit the concentration of CO, and using a CEMS	i. You have installed a CEMS to continuously monitor CO and either O_2 or CO_2 at the outlet of the oxidation catalyst according to the requirements in §63.6625(a); and
		ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and
		iii. The average concentration of CO calculated using §63.6620 is less than or equal to the CO emission limitation.

		The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average concentration measured during the 4-hour period.
7. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and using NSCR	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction, or the average reduction of emissions of THC determined from the initial performance test is equal to or greater than 30 percent; and
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
8. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and not using NSCR	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction or the average reduction of emissions of THC determined from the initial performance test is equal to or greater than 30 percent; and
		ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
9. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR	i. The average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet

		temperature during the initial performance test.
10. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR	i. The average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
11. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP	a. Reduce CO emissions	i. The average reduction of emissions of CO or formaldehyde, as applicable determined from the initial performance test is equal to or greater than the required CO or formaldehyde, as applicable, percent reduction.
12. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP	a. Limit the concentration of formaldehyde or CO in the stationary RICE exhaust	i. The average formaldehyde or CO concentration, as applicable, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde or CO emission limitation, as applicable.
13. Existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install an oxidation catalyst	i. You have conducted an initial compliance demonstration as specified in §63.6630(e) to show that the average reduction of emissions of CO is 93 percent or more, or the average CO concentration is less than or equal to 47 ppmvd at 15 percent O_2;
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b), or you have installed equipment to automatically shut down the engine if the catalyst inlet temperature exceeds 1350 °F.
14. Existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install NSCR	i. You have conducted an initial compliance demonstration as specified in §63.6630(e) to show that the average reduction of emissions of CO is 75 percent or more, the average CO concentration is less than or equal to 270 ppmvd at 15 percent O_2, or the average reduction of emissions of THC

		is 30 percent or more;
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b), or you have installed equipment to automatically shut down the engine if the catalyst inlet temperature exceeds 1250 °F.

[78 FR 6712, Jan. 30, 2013]

Table 6 to Subpart ZZZZ of Part 63—Continuous Compliance With Emission Limitations, and Other Requirements

As stated in §63.6640, you must continuously comply with the emissions and operating limitations and work or management practices as required by the following:

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP	a. Reduce CO emissions and using an oxidation catalyst, and using a CPMS	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved[a]; and ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
2. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP	a. Reduce CO emissions and not using an oxidation catalyst, and using a CPMS	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved[a]; and ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating

		limitations for the operating parameters established during the performance test.
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, new or reconstructed non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and using a CEMS	i. Collecting the monitoring data according to §63.6625(a), reducing the measurements to 1-hour averages, calculating the percent reduction or concentration of CO emissions according to §63.6620; and ii. Demonstrating that the catalyst achieves the required percent reduction of CO emissions over the 4-hour averaging period, or that the emission remain at or below the CO concentration limit; and
		iii. Conducting an annual RATA of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B, as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.
4. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and using NSCR	i. Collecting the catalyst inlet temperature data according to §63.6625(b); and
		ii. Reducing these data to 4-hour rolling averages; and
		iii. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		iv. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
5. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and not using NSCR	i. Collecting the approved operating parameter (if any) data according to §63.6625(b); and
		ii. Reducing these data to 4-hour rolling averages; and
		iii. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.

6. Non-emergency 4SRB stationary RICE with a brake HP ≥5,000 located at a major source of HAP	a. Reduce formaldehyde emissions	Conducting semiannual performance tests for formaldehyde to demonstrate that the required formaldehyde percent reduction is achieved, or to demonstrate that the average reduction of emissions of THC determined from the performance test is equal to or greater than 30 percent.[a]
7. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit[a]; and ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
8. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit[a]; and ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
9. Existing emergency and black start stationary RICE ≤500 HP located at a major source of HAP, existing non-emergency stationary RICE <100 HP located at a major source of HAP, existing emergency and black start stationary RICE located at an area source of HAP, existing non-	a. Work or Management practices	i. Operating and maintaining the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions; or ii. Develop and follow your own maintenance plan which must provide

emergency stationary CI RICE ≤300 HP located at an area source of HAP, existing non-emergency 2SLB stationary RICE located at an area source of HAP, existing non-emergency stationary SI RICE located at an area source of HAP which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, existing non-emergency 4SLB and 4SRB stationary RICE ≤500 HP located at an area source of HAP, existing non-emergency 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate 24 hours or less per calendar year, and existing non-emergency 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that are remote stationary RICE		to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions. **The emergency generator is maintained according to these requirements.**
10. Existing stationary CI RICE >500 HP that are not limited use stationary RICE	a. Reduce CO emissions, or limit the concentration of CO in the stationary RICE exhaust, and using oxidation catalyst	i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
11. Existing stationary CI RICE >500 HP that are not limited use stationary RICE	a. Reduce CO emissions, or limit the concentration of CO in the stationary RICE exhaust, and not using oxidation catalyst	i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and

		ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
12. Existing limited use CI stationary RICE >500 HP	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and using an oxidation catalyst	i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
13. Existing limited use CI stationary RICE >500 HP	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and not using an oxidation catalyst	i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and

		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
14. Existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install an oxidation catalyst	i. Conducting annual compliance demonstrations as specified in §63.6640(c) to show that the average reduction of emissions of CO is 93 percent or more, or the average CO concentration is less than or equal to 47 ppmvd at 15 percent O_2; and either ii. Collecting the catalyst inlet temperature data according to §63.6625(b), reducing these data to 4-hour rolling averages; and maintaining the 4-hour rolling averages within the limitation of greater than 450 °F and less than or equal to 1350 °F for the catalyst inlet temperature; or iii. Immediately shutting down the engine if the catalyst inlet temperature exceeds 1350 °F.
15. Existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install NSCR	i. Conducting annual compliance demonstrations as specified in §63.6640(c) to show that the average reduction of emissions of CO is 75 percent or more, the average CO concentration is less than or equal to 270 ppmvd at 15 percent O_2, or the average reduction of emissions of THC is 30 percent or more; and either ii. Collecting the catalyst inlet temperature data according to §63.6625(b), reducing these data to 4-hour rolling averages; and maintaining the 4-hour rolling averages within the limitation of greater than or equal to 750 °F and less than or equal to 1250 °F for the catalyst inlet temperature; or iii. Immediately shutting down the engine if the catalyst inlet temperature exceeds 1250 °F.

[a]After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

[78 FR 6715, Jan. 30, 2013]

Table 7 to Subpart ZZZZ of Part 63—Requirements for Reports

As stated in §63.6650, you must comply with the following requirements for reports:

For each . . .	You must submit a . . .	The report must contain . . .	You must submit the report . . .
1. Existing non-emergency, non-black start stationary RICE 100≤HP≤500 located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE >500 HP located at a major source of HAP; existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE >300 HP located at an area source of HAP; new or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP; and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP	Compliance report	a. If there are no deviations from any emission limitations or operating limitations that apply to you, a statement that there were no deviations from the emission limitations or operating limitations during the reporting period. If there were no periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), a statement that there were not periods during which the CMS was out-of-control during the reporting period; or	i. Semiannually according to the requirements in §63.6650(b)(1)-(5) for engines that are not limited use stationary RICE subject to numerical emission limitations; and ii. Annually according to the requirements in §63.6650(b)(6)-(9) for engines that are limited use stationary RICE subject to numerical emission limitations.
		b. If you had a deviation from any emission limitation or operating limitation during the reporting period, the information in §63.6650(d). If there were periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), the information in §63.6650(e); or	i. Semiannually according to the requirements in §63.6650(b).
		c. If you had a malfunction during the reporting period, the information in §63.6650(c)(4).	i. Semiannually according to the requirements in §63.6650(b).
2. New or reconstructed non-emergency stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	Report	a. The fuel flow rate of each fuel and the heating values that were used in your calculations, and you must demonstrate that the percentage of heat input provided by landfill gas or digester gas, is equivalent to 10 percent or more of the gross heat input on an annual basis; and	i. Annually, according to the requirements in §63.6650.
		b. The operating limits provided in your federally enforceable permit, and any deviations from	i. See item 2.a.i.

		these limits; and	
		c. Any problems or errors suspected with the meters.	i. See item 2.a.i.
3. Existing non-emergency, non-black start 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that operate more than 24 hours per calendar year	Compliance report	a. The results of the annual compliance demonstration, if conducted during the reporting period.	i. Semiannually according to the requirements in §63.6650(b)(1)-(5).
4. Emergency stationary RICE that operate or are contractually obligated to be available for more than 15 hours per year for the purposes specified in §63.6640(f)(2)(ii) and (iii) or that operate for the purposes specified in §63.6640(f)(4)(ii)	Report	a. The information in §63.6650(h)(1)	i. annually according to the requirements in §63.6650(h)(2)-(3).

[78 FR 6719, Jan. 30, 2013]

Table 8 to Subpart ZZZZ of Part 63—Applicability of General Provisions to Subpart ZZZZ.

As stated in §63.6665, you must comply with the following applicable general provisions.

General provisions citation	Subject of citation	Applies to subpart	Explanation
§63.1	General applicability of the General Provisions	Yes.	
§63.2	Definitions	Yes	Additional terms defined in §63.6675.
§63.3	Units and abbreviations	Yes.	
§63.4	Prohibited activities and circumvention	Yes.	
§63.5	Construction and reconstruction	Yes.	
§63.6(a)	Applicability	Yes.	
§63.6(b)(1)-(4)	Compliance dates for new and reconstructed sources	Yes.	
§63.6(b)(5)	Notification	Yes.	
§63.6(b)(6)	[Reserved]		
§63.6(b)(7)	Compliance dates for new and reconstructed area sources that become major sources	Yes.	
§63.6(c)(1)-(2)	Compliance dates for existing sources	Yes.	
§63.6(c)(3)-(4)	[Reserved]		

§63.6(c)(5)	Compliance dates for existing area sources that become major sources	Yes.	
§63.6(d)	[Reserved]		
§63.6(e)	Operation and maintenance	No.	
§63.6(f)(1)	Applicability of standards	No.	
§63.6(f)(2)	Methods for determining compliance	Yes.	
§63.6(f)(3)	Finding of compliance	Yes.	
§63.6(g)(1)-(3)	Use of alternate standard	Yes.	
§63.6(h)	Opacity and visible emission standards	No	Subpart ZZZZ does not contain opacity or visible emission standards.
§63.6(i)	Compliance extension procedures and criteria	Yes.	
§63.6(j)	Presidential compliance exemption	Yes.	
§63.7(a)(1)-(2)	Performance test dates	Yes	Subpart ZZZZ contains performance test dates at §§63.6610, 63.6611, and 63.6612.
§63.7(a)(3)	CAA section 114 authority	Yes.	
§63.7(b)(1)	Notification of performance test	Yes	Except that §63.7(b)(1) only applies as specified in §63.6645.
§63.7(b)(2)	Notification of rescheduling	Yes	Except that §63.7(b)(2) only applies as specified in §63.6645.
§63.7(c)	Quality assurance/test plan	Yes	Except that §63.7(c) only applies as specified in §63.6645.
§63.7(d)	Testing facilities	Yes.	
§63.7(e)(1)	Conditions for conducting performance tests	No.	Subpart ZZZZ specifies conditions for conducting performance tests at §63.6620.
§63.7(e)(2)	Conduct of performance tests and reduction of data	Yes	Subpart ZZZZ specifies test methods at §63.6620.
§63.7(e)(3)	Test run duration	Yes.	
§63.7(e)(4)	Administrator may require other testing under section 114 of the CAA	Yes.	
§63.7(f)	Alternative test method provisions	Yes.	
§63.7(g)	Performance test data analysis, recordkeeping, and reporting	Yes.	
§63.7(h)	Waiver of tests	Yes.	
§63.8(a)(1)	Applicability of monitoring requirements	Yes	Subpart ZZZZ contains specific requirements for monitoring at §63.6625.
§63.8(a)(2)	Performance specifications	Yes.	

§63.8(a)(3)	[Reserved]		
§63.8(a)(4)	Monitoring for control devices	No.	
§63.8(b)(1)	Monitoring	Yes.	
§63.8(b)(2)-(3)	Multiple effluents and multiple monitoring systems	Yes.	
§63.8(c)(1)	Monitoring system operation and maintenance	Yes.	
§63.8(c)(1)(i)	Routine and predictable SSM	No	
§63.8(c)(1)(ii)	SSM not in Startup Shutdown Malfunction Plan	Yes.	
§63.8(c)(1)(iii)	Compliance with operation and maintenance requirements	No	
§63.8(c)(2)-(3)	Monitoring system installation	Yes.	
§63.8(c)(4)	Continuous monitoring system (CMS) requirements	Yes	Except that subpart ZZZZ does not require Continuous Opacity Monitoring System (COMS).
§63.8(c)(5)	COMS minimum procedures	No	Subpart ZZZZ does not require COMS.
§63.8(c)(6)-(8)	CMS requirements	Yes	Except that subpart ZZZZ does not require COMS.
§63.8(d)	CMS quality control	Yes.	
§63.8(e)	CMS performance evaluation	Yes	Except for §63.8(e)(5)(ii), which applies to COMS.
		Except that §63.8(e) only applies as specified in §63.6645.	
§63.8(f)(1)-(5)	Alternative monitoring method	Yes	Except that §63.8(f)(4) only applies as specified in §63.6645.
§63.8(f)(6)	Alternative to relative accuracy test	Yes	Except that §63.8(f)(6) only applies as specified in §63.6645.
§63.8(g)	Data reduction	Yes	Except that provisions for COMS are not applicable. Averaging periods for demonstrating compliance are specified at §§63.6635 and 63.6640.
§63.9(a)	Applicability and State delegation of notification requirements	Yes.	
§63.9(b)(1)-(5)	Initial notifications	Yes	Except that §63.9(b)(3) is reserved.
		Except that §63.9(b) only applies as specified in §63.6645.	
§63.9(c)	Request for compliance extension	Yes	Except that §63.9(c) only applies as specified in §63.6645.
§63.9(d)	Notification of special compliance requirements for new sources	Yes	Except that §63.9(d) only applies as specified in §63.6645.

§63.9(e)	Notification of performance test	Yes	Except that §63.9(e) only applies as specified in §63.6645.
§63.9(f)	Notification of visible emission (VE)/opacity test	No	Subpart ZZZZ does not contain opacity or VE standards.
§63.9(g)(1)	Notification of performance evaluation	Yes	Except that §63.9(g) only applies as specified in §63.6645.
§63.9(g)(2)	Notification of use of COMS data	No	Subpart ZZZZ does not contain opacity or VE standards.
§63.9(g)(3)	Notification that criterion for alternative to RATA is exceeded	Yes	If alternative is in use.
		Except that §63.9(g) only applies as specified in §63.6645.	
§63.9(h)(1)-(6)	Notification of compliance status	Yes	Except that notifications for sources using a CEMS are due 30 days after completion of performance evaluations. §63.9(h)(4) is reserved.
			Except that §63.9(h) only applies as specified in §63.6645.
§63.9(i)	Adjustment of submittal deadlines	Yes.	
§63.9(j)	Change in previous information	Yes.	
§63.10(a)	Administrative provisions for recordkeeping/reporting	Yes.	
§63.10(b)(1)	Record retention	Yes	Except that the most recent 2 years of data do not have to be retained on site.
§63.10(b)(2)(i)-(v)	Records related to SSM	No.	
§63.10(b)(2)(vi)-(xi)	Records	Yes.	
§63.10(b)(2)(xii)	Record when under waiver	Yes.	
§63.10(b)(2)(xiii)	Records when using alternative to RATA	Yes	For CO standard if using RATA alternative.
§63.10(b)(2)(xiv)	Records of supporting documentation	Yes.	
§63.10(b)(3)	Records of applicability determination	Yes.	
§63.10(c)	Additional records for sources using CEMS	Yes	Except that §63.10(c)(2)-(4) and (9) are reserved.
§63.10(d)(1)	General reporting requirements	Yes.	
§63.10(d)(2)	Report of performance test results	Yes.	
§63.10(d)(3)	Reporting opacity or VE observations	No	Subpart ZZZZ does not contain opacity or VE standards.
§63.10(d)(4)	Progress reports	Yes.	
§63.10(d)(5)	Startup, shutdown, and malfunction	No.	

	reports		
§63.10(e)(1) and (2)(i)	Additional CMS Reports	Yes.	
§63.10(e)(2)(ii)	COMS-related report	No	Subpart ZZZZ does not require COMS.
§63.10(e)(3)	Excess emission and parameter exceedances reports	Yes.	Except that §63.10(e)(3)(i) (C) is reserved.
§63.10(e)(4)	Reporting COMS data	No	Subpart ZZZZ does not require COMS.
§63.10(f)	Waiver for recordkeeping/reporting	Yes.	
§63.11	Flares	No.	
§63.12	State authority and delegations	Yes.	
§63.13	Addresses	Yes.	
§63.14	Incorporation by reference	Yes.	
§63.15	Availability of information	Yes.	

[75 FR 9688, Mar. 3, 2010, as amended at 78 FR 6720, Jan. 30, 2013]

5.0 Emissions

5.1 Potential to Emit

Emission estimates were made for:

- New source review (NSR) pollutants including PM10, PM2.5, SO2, CO, NOx, VOC, and CO2e,
- Federal HAPs [listed in CAA Section 112(b)], and
- State TAPs [listed in IDAPA 58.01.01.585 & -.586].

Post Project potential emissions were calculated for all of the new equipment plus the existing equipment at the facility operating at the maximum production rates expected for the facility after the expansion. Pre-Project potential emissions were calculated for the existing equipment operating at the maximum production levels allowed in the current air permit.

5.1.1 Post Project Emissions

The estimated PTE emissions of NSR pollutants from the Pocatello plant after the project is completed (post project) are presented in Table 5-1. These emissions are based on the following throughput rates:

- Grain throughput: 324,000 MT/year
- Malt produced: 292,000 MT/year
- Pellet production: 5 MT/hr (daily average): 27,000 MT/year
- Sulfur burned in the Malthouse Kiln 1: 10 lb S/hr (daily average); 27,380 lb S/yr
- Sulfur burned in the new Kiln (K2): none
- Natural gas usage in Malthouse Kiln 1 heat exchangers: 0.0775 MM cf/hr; 290 MM cf/year
- Natural gas usage in Malthouse boilers: 0.00625 MM cf/hr; 21.04 MM cf/year
- Natural gas usage in new Kiln 2 heat exchangers: 0.071 MM cf/hr; 420 MM cf/year
- Natural gas usage in new germination boilers: 0.008 MM cf/hr; 70.1 MM cf/year
- Sodium hypochlorite (solid) usage in germination beds: 50 lb/cleaning, 1000 lb/yr
- Sodium hypochlorite (liquid) usage in germination beds: 250 lb/cleaning; 240,240 lb/yr
- Sodium hypochlorite (solid) usage in germination vessels: 50 lb/cleaning; 1500 lb/yr
- Sodium hypochlorite (liquid) usage in germination beds: 250 lb/cleaning; 300,400 lb/yr

GWM will restrict the hourly and annual natural gas usage in the existing Malthouse boilers (BS1) and restrict the annual natural gas usage in the existing Malthouse kiln new heaters (KS1-KS5) and new kiln heaters (KB1-KB4).

The detailed tables showing how the post project emissions were calculated are provided in Section 5.2 and electronically on the enclosed CD.

Table 5-1: Post Project Facility-Wide PTE for Regulated Air Pollutants

Source	Emission Point	PM10 T/yr	PM2.5 T/yr	SO2 T/yr	NOx T/yr	CO T/yr	VOC T/yr	CO2e T/yr
Truck Barley Unload - Uncaptured[1]	TB	0.0515	0.0087	0	0	0	0	0
Truck Barley Unload - Stack	BH1	0.0049	0.0008	0	0	0	0	0
Rail Barley Unload -Uncaptured	RB	0.0384	0.0064	0	0	0	0	0
Rail Barley Unload - Stack	BH1	0.0036	0.0006	0	0	0	0	0
Barley Headhouse Transfers	BH1 & BH2	0.0606	0.0103	0	0	0	0	0
Barley Transfers Before Cleaning	BH2	0.0303	0.0052	0	0	0	0	0
Barley Transfers After Cleaning	BH2	0.0303	0.0052	0	0	0	0	0
Steep Tanks Fill Conveyor 1 (STC1)	S1	0.0168	0.0029	0	0	0	0	0
Steep Tanks Fill Conveyor 2 (STC2)	S2	0.0168	0.0029	0	0	0	0	0
Feed Barley Transfer to Bins	BH1	0.0011	0.0002	0	0	0	0	0
Feed Barley Loading for Shipment - Uncaptured[6]	TB	0.0096	0.0016	0	0	0	0	0
Feed Barley Loading for Shipment - Stack	BH3	0.0009	0.0002	0	0	0	0	0
Pellet Mill Transfers	BH1	0.0025	0.0004	0	0	0	0	0
Truck Pellet Loading for Shipment[3]	TB	0.0088	0.0062	0	0	0	0	0
Rail Pellet Loading for Shipment	RB	0.0088	0.0062	0	0	0	0	0
Malt Transfers	BH1 & BH3	0.0273	0.0047	0	0	0	0	0
Kiln 2 New Malt Leg Conveyor (NML)	S32	0.0151	0.0026	0	0	0	0	0
Malt Analysis Bins 1-2-fill (BA1)	S33	0.0076	0.0013	0	0	0	0	0
Malt Analysis Bins 1-2-reclaim (BA2)	S34	0.0076	0.0013	0	0	0	0	0
Byproduct Cyclone (KBPC)	S35	0.0100	0.0100	0	0	0	0	0
Kiln 2 New Malt Conveyor (NMC3)	S36	0.0151	0.0026	0	0	0	0	0
Micro Bins 1-4- fill conveyor (MBC)	S37	0.0014	0.0002	0	0	0	0	0
Malt Storage Bins 1-5- fill conveyor 1 (NMSBC1)	S46	0.0137	0.0023	0	0	0	0	0
Malt Storage Bins 6-10- fill conveyor 2 (NMSBC2)	S47	0.0137	0.0023	0	0	0	0	0
Rail Malt Loading for Shipment[4]	RB	0.3194	0.0537	0	0	0	0	0
Truck Malt Loading for Shipment	TB	0.4466	0.0755	0	0	0	0	0
Malt House Kilning- Kiln 1	KSE	5.5404	3.5045	0	0	0	9.2950	0
Malt House Kilning Sulfur Combustion	KSE	0	0	20.4255	0	0	0	0
Barley Cleaning	BH2	0.0564	0.0009	0	0	0	0	0
Malt Cleaning (replacing some equipment)	BH2 & BH3	0.0509	0.0008	0	0	0	0	0
Pellet Mill Cleaning	BH1	0.0047	0.0001	0	0	0	0	0
Pellet Mill Cooler	CS	0.9801	0.9801	0	0	0	0	0
Germination Bed Sanitizing, Solid NaOCl	GBE 1-6	0	0	0	0	0	0	0
Germination Bed Sanitizing, Liquid NaOCl	GBE 1-6	0	0	0	0	0	0	0
Germination vessels (GV1-GV4), Solid NaOCl	S19-S26	0	0	0	0	0	0	0
Germination vessels (GV1-GV4), Liquid NaOCl	S19-S26	0	0	0	0	0	0	0
Kiln 2 (K2)	S31	6.9042	4.3672	0	0	0	11.5830	0
Kiln 2 (K2)- sulfur combustion	S31	0	0	0	0	0	0	0
Process CO2	Kilns, steeps & germination	0	0	0	0	0	0	26,000

Table 5-1: Post Project Facility-Wide PTE for Regulated Air Pollutants

Source	Emission Point	PM10 T/yr	PM2.5 T/yr	SO2 T/yr	NOx T/yr	CO T/yr	VOC T/yr	CO2e T/yr
Kiln 1 Burner K1	KS1	0.110	0.110	0.0087	0.5365	3.2915	0.0798	1740.51
Kiln 1 Burners K2 -K5	KS2	0.441	0.441	0.0348	2.1460	13.1660	0.3190	6962.03
Kiln 1 Burner K6	KS3	0.110	0.110	0.0087	0.5365	3.2915	0.0798	1740.51
Kiln 1 Burners K7 - K9	KS4	0.331	0.331	0.0261	1.6095	9.8745	0.2393	5221.52
Kiln 1 Burner K10	KS5	0.110	0.110	0.0087	0.5365	3.2915	0.0798	1740.51
Malt House Boilers 1&2[2]	BS1	0.0799	0.0799	0.0063	1.0518	0.8835	0.0578	1262.53
Pellet Mill Boiler	BS2	0.0832	0.0832	0.0066	1.0950	0.9198	0.0602	1314.38
GV boiler 1 (GVB1)	S38	0.0666	0.0666	0.0053	0.2628	0.7358	0.0482	1051.51
GV boiler 2 (GVB2)	S39	0.0666	0.0666	0.0053	0.2628	0.7358	0.0482	1051.51
GV boiler 3 (GVB3)- backup	S40	0.000	0.000	0.000	0.000	0.000	0.000	0.000
GV boiler 4 (GVB4)	S41	0.0666	0.0666	0.0053	0.2628	0.7358	0.0482	1051.51
GV boiler 5 (GVB5)	S42	0.0666	0.0666	0.0053	0.2628	0.7358	0.0482	1051.51
GV boiler 6 (GVB6)- backup	S43	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Kiln 2 Burner 1 (KB1)	S27	0.3990	0.3990	0.0315	1.9425	11.9175	0.2888	6301.84
Kiln 2 Burner 2 (KB2)	S28	0.3990	0.3990	0.0315	1.9425	11.9175	0.2888	6301.84
Kiln 2 Burner 3 (KB3)	S29	0.3990	0.3990	0.0315	1.9425	11.9175	0.2888	6301.84
Kiln 2 Burner 4 (KB4)	S30	0.3990	0.3990	0.0315	1.9425	11.9175	0.2888	6301.84
Steep Blg. Makeup Air Unit 1 (MAU1)	S44	0.0728	0.0728	0.0058	0.9583	0.8050	0.0527	1150.35
Steep Blg. Makeup Air Unit 2 (MAU2)	S45	0.0728	0.0728	0.0058	0.9583	0.8050	0.0527	1150.35
Emergency gnerator (EG1)	EG	0.0066	0.0066	0.0006	0.0930	0.0200	0.0074	3.45
Post Project Totals		**17.98**	**12.35**	**20.68**	**18.34**	**86.96**	**23.25**	**77,700**

5.1.2 Pre-Project Emissions

The estimated PTE emissions of NSR pollutants from the Pocatello plant after the project is completed (pre-project) are presented in Table 5-2. These emissions are based on the maximum throughput limits and emission limits listed in the existing permit including:

- Grain throughput: 155,500 MT/year
- Malt produced: 118,200 MT/year
- Pellet production: 4.6 MT/hr (daily average); 11,300 MT/year
- Sulfur burned in the Malthouse Kiln: 10 lb S/hr (daily average); 27,380 lb S/yr
- Natural gas usage in Malthouse Kiln burners: 0.069 MM cf/hr; 310 MM cf/year
- Natural gas usage in Malthouse boilers: 0.05 MM cf/hr; 21.04 MM cf/year
- Sodium hypochlorite (solid) usage in germination beds: 50 lb/cleaning, 1000 lb/yr
- Sodium hypochlorite (liquid) usage in germination beds: 250 lb/cleaning, 240,240 lb/yr

The detailed tables showing how the pre-project emissions were calculated are provided in Section 5.2 and electronically on the enclosed drive.

A comparison of the facility total emissions before and after the project is presented in Table 5-3. Annual and hourly emissions of SO2 do not increase very much because the increase is only due to an increase in natural gas combustion. The changes in SO2 hourly and annual emissions are less than the Modeling Level I thresholds, so dispersion modeling for SO2 impacts is not required.

Table 5-2: Pre-Project Facility-Wide PTE for Regulated Air Pollutants

Source	Emission Point	PM10 T/yr	PM2.5 T/yr	SO2 T/yr	NOx T/yr	CO T/yr	VOC T/yr	CO2e T/yr
Truck Barley Unload - Uncaptured	TB	0.0388	0.0065	0	0	0	0	0
Truck Barley Unload - Stack	BH1	0.0037	0.0006	0	0	0	0	0
Rail Barley Unload - Uncaptured	RB	0.0099	0.0017	0	0	0	0	0
Rail Barley Unload - Stack	BH1	0.0009	0.0002	0	0	0	0	0
Barley Headhouse Transfers	BH1 & BH2	0.0309	0.0053	0	0	0	0	0
Barley Transfers Before Cleaning	BH2	0.0165	0.0028	0	0	0	0	0
Barley Transfers After Cleaning	BH2	0.0165	0.0028	0	0	0	0	0
Feed Barley Transfer to Bins	BH1	0.0009	0.0001	0	0	0	0	0
Feed Barley Loading for Shipment - Uncaptured	TB	0.0075	0.0013	0	0	0	0	0
Feed Barley Loading for Shipment - Stack	BH3	0.0007	0.0001	0	0	0	0	0
Pellet Mill Transfers	BH1	0.0011	0.0002	0	0	0	0	0
Truck Pellet Loading for Shipment	TB	0.0015	0.0010	0	0	0	0	0
Rail Pellet Loading for Shipment	RB	0.0035	0.0024	0	0	0	0	0
Malt Transfers	BH1 & BH3	0.0111	0.0019	0	0	0	0	0
Rail Malt Loading for Shipment	RB	0.0286	0.0048	0	0	0	0	0
Truck Malt Loading for Shipment	TB	1.5080	0.2548	0	0	0	0	0
Malt House Kilning- Kiln 1	KSE	5.0367	3.1842	0	0	0	8.45	0
Malt House Kilning Sulfur Combustion	KSE	0	0	20.4255	0	0	0	0
Barley Cleaning	BH2	0.0308	0.0005	0	0	0	0	0
Malt Cleaning	BH2 & BH3	0.0206	0.0003	0	0	0	0	0
Pellet Mill Cleaning	BH1	0.0020	0.0000	0	0	0	0	0
Pellet Mill Cooler	CS	0.4092	0.4092	0	0	0	0	0
Germination Bed Sanitizing, Solid NaOCl	GBE 1-6	0	0	0	0	0	0	0
Germination Bed Sanitizing, Liquid NaOCl	GBE 1-6	0	0	0	0	0	0	0
Process CO2	Kilns, steeps & germination	0	0	0	0	0	0	10,523
Kiln Burner #1	KS1	0.1179	0.1179	0.00931	1.30294	1.55112	0.08531	1,862
Kiln Burners #2 -#5	KS2	0.4715	0.4715	0.03723	5.21176	6.20448	0.34125	7,448
Kiln Burner #6	KS3	0.1179	0.1179	0.00931	1.30294	1.55112	0.08531	1,862
Kiln Burners #7 - #9	KS4	0.3537	0.3537	0.02792	3.90882	4.65336	0.25593	5,586
Kiln Burner #10	KS5	0.1179	0.1179	0.00931	1.30294	1.55112	0.08531	1,862
Malt House Boilers 1&2[2]	BS1	0.0799	0.0799	0.00631	0.88351	1.05180	0.05785	1,263
Pellet Mill Boiler	BS2	0.0580	0.0580	0.00458	0.64109	0.76320	0.04198	916
Project Totals		**8.50**	**5.20**	**20.53**	**14.55**	**17.33**	**9.40**	**31,320.35**

Table 5-3: Changes in PTE for Regulated Air Pollutants

Annual	PM10	PM2.5	SO2	NOx	CO	VOC	CO2e
	T/yr	T/yr	T/yr	T/yr	T/yr	T/yr	T/yr
Pre-Project PTE minus fugitive emissions	8.50	5.20	20.53	14.55	17.33	9.40	31,320
Post Project PTE minus fugitive emissions	17.98	12.35	20.68	18.34	86.96	23.25	77,700
Changes in Potential to Emit	9.48	7.15	0.15	3.79	69.63	13.85	46,380

Hourly	PM10	PM2.5	SO2	NOx	CO	VOC
	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
Pre-Project PTE minus fugitive emissions	4.90	2.52	14.99	12.15	10.21	3.06
Post Project PTE minus fugitive emissions	7.50	4.24	15.03	8.90	35.83	6.48
Changes in Potential to Emit	2.60	1.72	0.04	-3.25	25.62	3.42

5.1.3 Post Project HAP and TAP Emissions

The estimated PTE emissions of HAP and TAP pollutants from the Pocatello plant after the project is completed (post project) are presented in Tables 5-4 through 5-6. The Post Project controlled PTE emissions are based on the throughput rates listed for Post Project operations in Section 5.1.1.

The project's potential HAP emissions are compared to major source thresholds in Table 5-4. The facility will remain as a minor source of HAPs. Non-carcinogenic and Carcinogenic TAP emissions for Pre-project and Post Project are presented in Tables 5-5 and 5-6, respectively.

Emissions of chlorine and formaldehyde exceed the modeling screening emission levels (EL) and require further analysis. Model results for these TAPs are presented in Section 7 of this application.

Table 5-4: HAP Uncontrolled PTE and PTE Compared to the Major Source Thresholds

HAP Pollutant	Uncontrolled PTE	PTE	Major Source Threshold	Uncontrolled PTE Exceeds Major Source Threshold and PTE Exceeds Major Source Threshold
	T/yr	T/yr	T/yr	Y/N
Acetaldehyde	0.00401	0.00185	10	No
Acrolein	0.00252	0.00116	10	No
Benzene	0.00747	0.00345	10	No
Ethyl Benzene	0.00887	0.00409	10	No
Formaldehyde	0.01587	0.00732	10	No
Hexane	0.00588	0.00271	10	No
Naphthalene	0.00028	0.00013	10	No
PAH's (including naphthalene)	0.00037	0.00017	10	No
Toluene	0.03417	0.01576	10	No
Xylenes	0.02539	0.01171	10	No
Chlorine	1.19135	1.19135	10	No
Site Total	**1.29618**	**1.23972**	**25**	**No**

Table 5-5: Pre- and Post Project PTE for Non-Carcinogenic TAP

Non-Carcinogenic TAP	Pre-Project 24-hour Average Emission Rates	Post Project 24-hour Average Emission Rates	Change in 24-hour Average Emission Rates	Non-Carcinogenic Screening Level (EL)	Exceeds Screening Level?
	lb/hr	lb/hr	lb/hr	lb/hr	Y/N
Acrolein	0.00033	0.00046	0.00013	0.017	No
Ethyl Benzene	0.00115	0.00161	0.00046	29	No
Hexane	0.00077	0.00107	0.00030	12	No
Naphthalene	0.00004	0.00005	0.00001	3.33	No
Toluene	0.00445	0.00620	0.00175	25	No
Xylenes	0.00330	0.00461	0.00131	29	No
Chlorine*	**0.5375**	**1.0750**	**0.538**	**0.2**	**Yes**

* Dispersion modeling was performed for chlorine emissions to show compliance with the AAC

Table 5-6: Pre- and Post Project PTE for Carcinogenic TAP

Carcinogenic TAP	Pre-Project Annual Average Emission Rates	Post Project Annual Average Emission Rates	Change in Annual Average Emission Rates	Carcinogenic Screening Level (EL)	Exceeds Screening Level?
	lb/hr	lb/hr	lb/hr	lb/hr	Y/N
Acetaldehyde	1.71E-04	4.23E-04	2.52E-04	3.0E-03	No
Benzene	3.16E-04	7.87E-04	4.71E-04	8.0E-04	No
Formaldehyde*	**6.72E-04**	**1.67E-03**	**1.00E-03**	**5.1E-04**	**Yes**
PAH's (including naphthalene)	1.58E-05	3.93E-05	2.35E-05	9.1E-05	No

* Dispersion modeling was performed for formaldehyde emissions to show compliance with the AACC

5.2 Emission Estimates

5.2.1 Emission Factors

This section describes the emission factors used in the emission estimates. The emissions from the facility were calculated using the maximum production throughput rates multiplied by emission factors applicable to the process. The emission factors were obtained from source tests on similar equipment, from published sources like EPA and California air pollution control districts, or were calculated using safety data sheets or process information.

Supporting information on the emission factors used in this analysis is presented in Appendix E.

PM10 and PM2.5 Emission Factor

PM10 and PM2.5 are emitted from material handling, grain and malt cleaning, the pellet mill system, the kilns and combustion sources. USEPA particulate emission factors were used to develop PM10 and PM2.5 emission estimates for the existing material handling operations (Ref. AP-42, Section 9.9.1). The removal efficiency of 99.5% for the baghouses was obtained from USEPA Air Pollution Control Technology Fact Sheet for Fabric Filters (EPA-452/F-03-024). A copy of AP-42 Section 9.9.1 is provided in Appendix E-1, for reference.

For consistency, the PM10 and PM2.5 emission estimates for the new material handling operations were based on the same emission factors as used for the existing material handling operations. Donaldson Torit dust filters will be used to control dust from the new material handling operations. Donaldson Torit issued an emission guarantee that Total Particulate emissions will not exceed 0.002 gr/dscf from each new filter. A copy of the guarantee is provided in Appendix E-2.

Emission rates from the new material handling operations using the Donaldson Torit guarantee were compared to the emission rates estimated using the USEPA emission factor, as shown in Table 5-7. In every case but one, the USEPA factors produced a PM10 emission rate that is greater than the vendor-based Total PM emission rate indicating that using the USEPA factors for permitting is a conservative estimate of PM10 emissions. Because the emissions from the kiln by-products cyclone filter (KBPCF) are significantly higher than the USEPA based emissions estimate, the vendor's 0.002 gr/dscf factor was used to calculate PM emissions for this source only.

Table 5-7: Comparison of New Filter Emissions Using Vendor and USEPA Factors

New Material Handling Source	Exhaust Air Flow Rate	Based on Vendor Factor of 0.002 gr/dscf	Based on USEPA Emission Factor
		Total PM	PM10
	ACFM	lb/hr	lb/hr
STC1F	285	0.0049	0.030
STC2F	285	0.0049	0.030
NMLF	1500	0.0257	0.041
BA1F	390	0.0067	0.041
BA2F	390	0.0067	0.041
KBPCF	390	0.0067	0.001
NMC3F	285	0.0049	0.030

New Material Handling	Exhaust Air Flow Rate	Based on Vendor Factor of 0.002 gr/dscf	Based on USEPA Emission Factor
MBCF	97.5	0.0017	0.008
NMSBC1F	285	0.0049	0.030
NMSBC2F	285	0.0049	0.030

PM10 and PM2.5 emissions for malt cleaning processes were based on the USEPA AP-42 Section 9.9.1 emission factors with adjustments for differing control methods.

Emissions from the Pellet Mill were based on a source test. Source testing was conducted on the Pellet Mill Cooler cyclone exhaust on April 27, 2000. The source testing revealed and emission rate of 0.066 lb PM10 / ton throughput. For these calculations it is assumed that PM2.5 is 100% of PM10. These emission factors include the presence of the cyclone and no further removal efficiency is provided in the calculation. A copy of the source test is provided in Appendix E-3

PM emission factors for the kilns were developed using the October 14, 2005 source test at GWM Pocatello plant which indicated a filterable PM emission of 0.95 lb/hr equating to a filterable PM emission rate of 0.057 lb/T. (Appendix E-4) In AP-42, Section 9.9.1, Table 9.9.1-2, Gas Fired Malt Kiln, the filterable PM is 68.3% of the total PM emission factor (0.19/(0.19+0.088)=0.683). Assuming the Pocatello kiln had the same ratio of filterable to total PM emission as in AP42, the resulting total (filterable + condensable) kiln Total PM emission factor is the filterable test result divided by 68.3% (0.057/0.683) or 0.0835 lb/T. A PM10 fraction of 92.8% and a PM2.5 fraction of 58.7% were developed from emission information presented in AP-42, Section 9.9.1, Table 9.9.1-2, Gas Fired Malt Kiln (Appendix E-1).

The kiln burners, boilers and make-up air heaters are all fired with natural gas. The USEPA AP-42 Section 1.4 PM emission factor of 7.6 lb/MM cf for natural gas combustion was used in the PM emission calculations for these sources. (Appendix E-5). For the diesel-fired emergency generator, USEPA AP-42 Section 3.3 emission factors were used (Appendix E-6).

SO2 Emission Factors

SO2 emissions are generated from sulfur burning in the existing malthouse kiln and from combustion sources. Sulfur will not be burned in the new kiln (K2).

SO2 emission factors for malthouse kilning sulfur combustion were developed from a source test conducted at GWM's Los Angeles, California facility. Source test data are provided in Appendix E-7. The data indicate a maximum SO2 emission rate of 1.492 lbs SO2 / lb sulfur burned or 2984 lbs SO2 /ton of sulfur burned. A portion of the SO2 is retained in the malt and not emitted.

The kiln burners, boilers and make-up air heaters are all fired with natural gas. The USEPA AP-42 Section 1.4 SO2 emission factor of 0.6 lb/MM cf for natural gas combustion was used in the SO2 emission calculations for these sources. (Appendix E-5). For the diesel-fired emergency generator, USEPA AP-42 Section 3.3 emission factors were used (Appendix E-6).

CO Emission Factors

CO is emitted from the natural gas combustion sources at the plant. These sources include the new kiln heaters, existing kiln burners, existing and new boilers, makeup air heaters and the emergency generator.

Maxon is the manufacturer for the new natural gas-fired burners in the four air heaters for the new kiln (KB1-KB4) and in the ten new air heaters for the existing kiln (KS1-KS5). Maxon has certified that the CO emissions from each burner will not be greater than 0.221 lb/MM Btu. A copy of the Maxon certification is provided in Appendix E-8.

The existing and new boilers and new make-up air heaters are all fired with natural gas. The USEPA AP-42 Section 1.4 CO emission factor of 84 lb/MM cf for natural gas combustion was used in the CO emission calculations for these sources. (Appendix E-5). For the diesel-fired emergency generator, USEPA AP-42 Section 3.3 emission factors were used (Appendix E-6).

NOx Emissions Factors

NOx is emitted from the natural gas combustion sources at the plant. These sources include the new kiln heaters, existing kiln burners, existing and new boilers, makeup air heaters and the emergency generator.

Maxon is the manufacturer for the new natural gas-fired low NOx burners in the four air heaters for the new kiln (KB1-KB4) and in the ten new air heaters for the existing kiln (KS1-KS5). Maxon has certified that the NOx emissions from each burner will not be greater than 0.036 lb/MM Btu. A copy of the Maxon certification is provided in Appendix E-8.

The six new germination boilers (GVB1-GVB6) all will have low NOx burners. Vendor literature on the boilers indicates that the boiler burners are tested and certified to meet SCAQMD NOx limits that will not exceed 20 ppm at 3% O_2. The vendor emission rate equates to a 30 lb/MM cf emission factor for NOx emissions from these boilers (Appendix E-9).

The existing boilers and new make-up air heaters are all fired with natural gas. The USEPA AP-42 Section 1.4 NOx emission factor of 100 lb/MM cf for natural gas combustion was used as the basis for the NOx emission calculations for these sources. (Appendix E-5).

For the diesel-fired emergency generator, USEPA AP-42 Section 3.3 emission factors were used (Appendix E-6).

VOC Emission Factors

VOC is emitted from the two kilns and combustion sources at the plant.

The kilning emission factor for VOCs was developed from kiln source tests conducted at GWM's Vancouver, Washington facility on August 25, 1994. Source test data is provided in Appendix E-7. Information from the source test indicates that during the 16-hour test period, 357,000 pounds of green malt were processed and the VOC emissions were 23.5 pounds. The resulting emission factor is calculated as follows:

Kilning VOC Emission Factor = (23.5 lb VOC / 357,000 lb malt) * (2000 lb/ton) = 0.13 lb VOC / ton Malt

The existing and new kiln burners, existing and new boilers and new make-up air heaters are all fired with natural gas. The USEPA AP-42 Section 1.4 VOC emission factor of 5.5 lb/MM cf for natural gas combustion was used in the VOC emission calculations for these sources. (Appendix E-5). For the diesel-fired emergency generator. USEPA AP-42 Section 3.3 emission factors were used (Appendix E-6).

CO2e Emission Factors

Malting processes and combustion sources produce greenhouse gas emissions, expressed as CO2 equivalents (CO2e).

CO2 is generated during the malting processes, mainly during steeping. In the GWM process there is about a 5% loss of dry matter per MT of malt produced or 50 kg/MT malt. Dry matter is essentially glucose (MW 180). Each molecule of glucose produces 6 molecules of CO2 or 1.47 kg of CO2 per kg of dry matter lost. 50 kg dry matter loss/MT malt X 1.47 kg CO2/kg dry matter loss = 73.5 kg CO2 generated/MT malt. Converting to pounds yields this emission factor: (73.5 kg/MT malt) X (1000 g/kg)/(454 g/lb) = 161.89 lb CO2/MT malt.

Fossil fuel combustion produces emissions of CO2e. The existing and new kiln burners, existing and new boilers and new make-up air heaters are all fired with natural gas. The USEPA AP-42 Section 1.4 emission factor of 120,035 lb/MM cf for natural gas combustion was used in the CO2e emission calculations for these sources. (Appendix E-5). For the diesel-fired emergency generator, USEPA AP-42 Section 3.3 emission factors were used (Appendix E-6).

HAP and TAP Emission Factors

Natural gas combustion generates emissions of HAPs and TAPs. The emission factors used for all of the natural gas-fired equipment were taken from “Natural Gas Fired External Combustion Equipment”, VCAPCD, AB2588 Combustion Emission Factors and the SJVAPCD Toxic Emission Factors at the website address of www.valley.org/busind/pto/emission_factors/emission_factors_idx.htm. The resulting emission factors are shown in Appendix E-11.

The germination beds and germination vessels are cleaned periodically using solid and liquid sodium hypochlorite solution. There is a potential for chlorine (Cl2) gas vapors, a HAP and a TAP, to be emitted during the cleaning activities. Emission factors were developed for both solid and liquid products based on a material balance calculation.

The emission factor for solid Sodium Hypochlorite was calculated conservatively by assuming 100% volatilization of chlorine contained in the product:

Solid Sodium Hypochlorite emission factor = (35.45 lb Cl^- /lb-mol)/(74.45 lb NaOCl/lb-mol) (2000 lb/T) = 960 lb Cl^- / T NaOCl
Two molecules of Cl^- per Cl2 equates to 960/2 = 480 lb Cl2/T solid NaOCl.

Similarly, the emission factor assumed 100% volatilization of chlorine contained in the 1.5 % solution of liquid Sodium Hypochlorite:

> Liquid Sodium Hypochlorite emission factor = 0.015 * (35.45 lb Cl/lb-mol)/ (74.45 lb NaOCl/lb-mol) (2000 lb/T) = 14.4 lb Cl^- / T NaOCl
> Two molecules of Cl^- per Cl2 equates to 14.4/2 = 7.2 lb Cl2/T liquid NaOCl.

5.2.2 Project Emission Estimates

Post Project emissions calculations are presented in these tables:

Table	Title
5-8	Estimated Emissions from Material Handling Operations
5-9	Estimated Emissions from Process Operations
5-10	Estimated Emissions from Fuel Burning Equipment
5-11	HAP and TAP Emissions from Natural Gas Combustion in Malthouse Boilers
5-12	HAP and TAP Emissions from Natural Gas Combustion in Pellet Mill Boiler
5-13	HAP and TAP Emissions from Natural Gas Combustion in Malthouse Kiln Burners
5-14	HAP and TAP Emissions from Natural Gas Combustion in Six New Germination Boilers
5-15	HAP and TAP Emissions from Natural Gas Combustion in New Kiln Burners
5-16	HAP and TAP Emissions from Natural Gas Combustion in Steep Makeup Air Heaters

Pre-Project emissions calculations are presented in these tables:

Table	Title
5-17	Pre-Project Emissions from Material Handling Operations
5-18	Pre-Project Emissions from Process Operations
5-19	Pre-Project Emissions from Fuel Burning Equipment
5-20	Pre-Project HAP and TAP Emissions from Natural Gas Combustion in Malthouse Boilers
5-21	Pre-Project HAP and TAP Emissions from Natural Gas Combustion in Pellet Mill Boiler
5-22	Pre-Project HAP and TAP Emissions from Natural Gas Combustion in Malthouse Kiln Burners

Table 5-8
Estimated Emissions from Material Handling Operations

Process Step	Emission Point[2]	Max. Hrly. Transfer Rate (MT/hr.)	Normal Hrly. Transfer Rate (MT/hr.)	Normal Annual Transfer Rate (MT/yr.)	Control Efficiency (%)[7]	Uncontrolled PM10 Emission Factor (lb/ton)	Uncontrolled PM2.5 Emission Factor (lb/ton)	Emission Factor Reference	Max. Hrly. PM10 Emissions (lb/hr)	Max. Hrly. PM2.5 Emissions (lb/hr)	Normal Annual PM10 Emissions (lb/yr)	Normal Annual PM2.5 Emissions (lb/yr)
Truck Barley Unload - Uncaptured[1]	TB	150	120	145000	0%	0.00065	0.00011	AP-42 Table 9.9.1-1 (3/03)	0.11	0.02	103.0	17.3
Truck Barley Unload - Stack	BH1	150	120	145000	99.50%	0.012	0.0021	AP-42 Table 9.9.1-1 (3/03)	0.01	0.00	9.8	1.6
Rail Barley Unload -Uncaptured	RB	150	120	179000	0%	0.00039	0.000065	AP-42 Table 9.9.1-1 (3/03)	0.06	0.01	76.8	12.8
Rail Barley Unload - Stack	BH1	150	120	179000	99.50%	0.0074	0.0012	AP-42 Table 9.9.1-1 (3/03)	0.01	0.00	7.3	1.2
Barley Headhouse Transfers	BH1 & BH2	150	150	648000	99.50%	0.034	0.0058	AP-42 Table 9.9.1-1 (3/03)	0.03	0.00	121.2	20.7
Barley Transfers Before Cleaning	BH2	150	150	324000	99.50%	0.034	0.0058	AP-42 Table 9.9.1-1 (3/03)	0.03	0.00	60.6	10.3
Barley Transfers After Cleaning	BH2	150	150	324000	99.50%	0.034	0.0058	AP-42 Table 9.9.1-1 (3/03)	0.03	0.00	60.6	10.3
Steep Tanks Fill Conveyor 1 (STC1)	S1	160	160	180000	99.50%	0.034	0.0058	AP-42 Table 9.9.1-1 (3/03)	0.03	0.01	33.7	5.7
Steep Tanks Fill Conveyor 2 (STC2)	S2	160	160	180000	99.50%	0.034	0.0058	AP-42 Table 9.9.1-1 (3/03)	0.03	0.01	33.7	5.7
Feed Barley Transfer to Bins	BH1	150	150	12000	99.50%	0.034	0.0058	AP-42 Table 9.9.1-1 (3/03)	0.03	0.00	2.2	0.4
Feed Barley Loading for Shipment - Uncaptured[6]	TB	400	400	12000	0%	0.0015	0.00025	AP-42 Table 9.9.1-1 (3/03)	0.64	0.11	19.1	3.2
Feed Barley Loading for Shipment - Stack	BH3	400	400	12000	99.50%	0.028	0.00466	AP-42 Table 9.9.1-1 (3/03)	0.06	0.01	1.8	0.3
Pellet Mill Transfers	BH1	5	5	27000	99.50%	0.034	0.0058	AP-42 Table 9.9.1-1 (3/03)	0.0009	0.0002	5.0	0.9
Truck Pellet Loading for Shipment[3]	TB	6	6	20000	0%	0.0008	0.00056	AP-42 Table 9.9.1-2 (3/03)	0.01	0.004	17.6	12.3
Rail Pellet Loading for Shipment	RB	6	6	20000	0%	0.0008	0.00056	AP-42 Table 9.9.1-2 (3/03)	0.01	0.004	17.6	12.3
Malt Transfers	BH1 & BH3	150	75	292000	99.50%	0.034	0.0058	AP-42 Table 9.9.1-1 (3/03)	0.03	0.005	54.6	9.3
Kiln 2 New Malt Leg Conveyor (NML)	S32	219	219	162000	99.50%	0.034	0.0058	AP-42 Table 9.9.1-1 (3/03)	0.041	0.007	30.3	5.2
Malt Analysis Bins 1-2-fill (BA1)	S33	219	219	81000	99.50%	0.034	0.0058	AP-42 Table 9.9.1-1 (3/03)	0.041	0.007	15.1	2.6
Malt Analysis Bins 1-2-reclaim (BA2)	S34	219	219	81000	99.50%	0.034	0.0058	AP-42 Table 9.9.1-1 (3/03)	0.041	0.007	15.1	2.6
Kiln Byproduct Cyclone (KBPC)[8]	S35	5	5	15000	99.50%	0.001	0.001	Vendor guarantee total PM 0.002 gr/dscf	0.007	0.007	20.1	20.1
New Malt Conveyor 3 (NMC3)	S36	160	160	162000	99.50%	0.034	0.0058	AP-42 Table 9.9.1-1 (3/03)	0.030	0.005	30.3	5.2
Micro Bins 1-4- fill conveyor (MBC))	S37	44	44	15000	99.50%	0.034	0.0058	AP-42 Table 9.9.1-1 (3/03)	0.008	0.001	2.8	0.5
Malt Storage Bins 1-5- fill conveyor 1 (NMSBC1)	S46	160	160	146000	99.50%	0.034	0.0058	AP-42 Table 9.9.1-1 (3/03)	0.030	0.005	27.3	4.7
Malt Storage BIns 6-10- fill conveyor 2 (NMSBC2)	S47	160	160	146000	99.50%	0.034	0.0058	AP-42 Table 9.9.1-1 (3/03)	0.030	0.005	27.3	4.7
Rail Malt Loading for Shipment[4]	RB	180	180	264000	0%	0.0022	0.00037	AP-42 Table 9.9.1-1 (3/03)	0.44	0.07	638.9	107.4
Truck Malt Loading for Shipment	TB	20	20	28000	0%	0.029	0.0049	AP-42 Table 9.9.1-1 (3/03)	0.64	0.11	893.2	150.9
								Total	**2.4**	**0.42**	**2325**	**428**

Table 5-8
Estimated Emissions from Material Handling Operations

Emission Point Summary for Material Handling Processes[5]

Emission Point	Max. Hrly. PM10 Emissions (lb/hr)	Max. Hrly. PM2.5 Emissions (lb/hr)	Normal Annual PM10 Emissions (lb/yr)	Normal Annual PM2.5 Emissions (lb/yr)
TB	1.39	0.24	1033.0	183.8
RB	0.51	0.09	733.3	132.6
BH1	0.073	0.012	132.2	22.5
BH2	0.062	0.011	145.4	24.8
BH3	0.083	0.014	45.5	7.8
S1	0.03	0.01	33.66	5.74
S2	0.03	0.01	33.66	5.74
S32	0.04	0.01	30.29	5.17
S33	0.04	0.01	15.15	2.58
S34	0.04	0.01	15.15	2.58
S35	0.01	0.01	20.06	20.06
S36	0.03	0.01	30.29	5.17
S37	0.01	0.00	2.81	0.48
S46	0.03	0.01	27.30	4.66
S47	0.03	0.01	27.30	4.66
Totals	**2.4**	**0.4**	**2,325.1**	**428.3**

Footnotes for Table 5-8 - Estimated Emissions From Material Handling Operations

[1]The emission factors for truck unloading assumes 90% hopper trucks and 10% straight trucks and is weighted per EPA AP-42 guidance. In addition, because the truck unloading pit is vented to BH1 it is assumed that 5% of the generated emission become airborne as fugitive emissions. For example the PM emission factor is calculated as follows:

Truck Unloading Emission Factor = [(0.90)(0.035 lb/ton) + (0.10)(0.18 lb/ton)]0.05 = 0.0025 lb/ton

The railbay unloading operation is also vented to BH1. A 95% capture efficiency is also applied to the AP-42 emission factors.

[2]TB = Truck Bay; RB = Rail Bay; BH1 = Baghouse #1; BH2 = Baghouse #2; BH3 = Baghouse #3

[3]The PM2.5 emission factor for truck & rail pellet loading for shipment assumes the PM2.5 fraction is 17% of PM.

[4] It is assumed that malt loadout occurs 90% by rail and 10% by truck.

[5] Headhouse transfer and malt transfer operations are served by multiple baghouses. Emission estimates assume 80% of barley headhouse transfer emissions are vented to BH1 and 20% are vented to BH2. 80% of malt transfer emissions are vented to BH3 and 20% to BH1.

[6]Feed barley loadout operations are equipped with a cyclone side draw vacuum system which vents to BH3. A 95% capture efficiency is applied to the AP-42 emission factors with the remaining 5% assumed to be available to become airborne fugitive emissions.

[7]Control efficiency estimated from USEPA Air Pollution Control Technology Fact Sheet for Fabric Filters (EPA-452/F-03-024). This document indicates operating efficiencies of 95-99.9%. Use 99.5% for existing baghouses and 99.5% for new dust collectors.

[8] Donaldson Torit filter performance certified to be 0.002 gr/dscf for total particulate emissions. Filter (KBPCF) on kiln by-products cyclone is sized at 390 acfm.

Table 5-9
Estimated Emissions from Process Operations

Process Step	Emission Point[1]	Max/Normal Hrly. Transfer Rate (MT/hr.)	Normal Annual Transfer Rate (MT/yr.)	Control Efficiency (%)		PM10 Emission Factor (lb/ton)	PM2.5 Emission Factor (lb/ton)	SO2 Emission Factor (lb/T S)	VOC Emission Factor (lb/ton)	Cl2 Emission Factor (lb/T hypochlorite)	CO2 Emission Factor (lb/ton malt)	Emission Factor Reference	Max/Normal Hrly. PM10 Emissions (lb/hr)	Max/Normal Hrly. PM2.5 Emissions (lb/hr)	Normal Annual PM10 Emissions (lb/yr)	Normal Annual PM2.5 Emissions (lb/yr)	Max Hrly. SO2 Emissions (lb/hr)	Normal Annual SO2 Emissions (lb/yr)	Max Hrly. VOC Emissions (lb/hr)	Normal Annual VOC Emissions (lb/yr)	Max Hrly. Cl2 Emissions (lb/hr)	Normal Annual Cl2 Emissions (lb/yr)	Normal Annual CO2 Emissions (lb/yr)
Malt House Kilning- Kiln 1	KSE	16.74	130000	0%		0.0775	0.0490	0.0	0.13	0.0		Source Test[2]	1.43	0.90	11080.8	7009.1	0.0	0.0	2.39	18590.0	0.0	0.0	0
Malt House Kilning Sulfur Combustion	KSE	0.0045	12.45	0%		0	0	2984	0	0		Source Test[2]	0.00	0.00	0.0	0.0	14.9	40851.0	0.00	0.0	0.0	0.0	0
Barley Cleaning	BH2	150	324000	99.50%		0.063	0.00096	0	0	0		AP-42 Table 9.9.1-1 (3/03)[3]	0.05	0.00	112.9	1.7	0.0	0.0	0.00	0.0	0.0	0.0	0
Malt Cleaning (replacing some equipment)	BH2 & BH3	150	292,000	99.50%		0.063	0.00096	0	0	0		AP-42 Table 9.9.1-1 (3/03)[3]	0.05	0.00	101.7	1.5	0.0	0.0	0.00	0.0	0.0	0.0	0
Pellet Mill Cleaning	BH1	5	27000	99.50%		0.063	0.00096	0	0	0		AP-42 Table 9.9.1-1 (3/03)[3]	0.00	0.00	9.4	0.1	0.0	0.0	0.00	0.0	0.0	0.0	0
Pellet Mill Cooler	CS	5	27000	0%		0.066	0.066	0	0	0		Source Test[4]	0.36	0.36	1960.2	1960.2	0.0	0.0	0.00	0.0	0.0	0.0	0
Germination Bed Sanitizing, Solid NaOCl	GBE 1-6	0.023	0.45	0%		0	0	0	0	480		Mass Balance[5]	0.00	0.00	0.0	0.0	0.0	0.0	0.00	0.0	6.00	240.0	0
Germination Bed Sanitizing, Liquid NaOCl	GBE 1-6	0.114	120.12	0%		0	0	0	0	7.2		Mass Balance[5]	0.00	0.00	0.0	0.0	0.0	0.0	0.00	0.0	0.45	951.4	0
Germination vessels (GV1-GV4), Solid NaO	S19-S26	0.023	0.68	0%		0	0	0	0	480		Mass Balance[5]	0.00	0.00	0.0	0.0	0.0	0.0	0.00	0.0	6.00	360.0	0
Germination vessels (GV1-GV4), Liquid NaC	S19-S26	0.114	136.55	0%		0	0	0	0	7.2		Mass Balance[5]	0.00	0.00	0.0	0.0	0.0	0.0	0.00	0.0	0.45	1081.4	0
Kiln 2 (K2)	S31	21	162000	0%		0.0775	0.0490	0.0	0.13	0.0		Source Test[2]	1.79	1.13	13808.4	8734.4	0.0	0.0	3.00	23166.0	0.0	0.0	0
Kiln 2 (K2)- sulfur combustion	S31	0.0000	0.00	0%		0	0	2984	0	0		Source Test[2]	0.00	0.00	0.0	0.0	0.0	0.0	0.00	0.0	0.0	0.0	0
Process CO2 [8]	Kilns, steeps & germination		292,000	0%		0	0	0	0	0	161.89	Calculation of glucose loss from steeping & respiration	0.00	0.00	0.0	0.0	0.0	0.0	0.00	0.0	0.0	0.0	52,000,441
												Totals	**3.69**	**2.40**	**27,073.32**	**17,707.05**	**14.92**	**40,850.96**	**5.40**	**41,756.00**	**12.90**	**2,632.79**	**52,000,441**

Emission Point Summary for Process Operations[6]

Emission Point	Max/Normal Hrly. PM10 Emissions (lb/hr)	Max/Normal Hrly. PM2.5 Emissions (lb/hr)	Normal Annual PM10 Emissions (lb/yr)	Normal Annual PM2.5 Emissions (lb/yr)	Max Hrly. SO2 Emissions (lb/hr)	Normal Annual SO2 Emissions (lb/yr)	Max Hrly. VOC Emissions (lb/hr)	Normal Annual VOC Emissions (lb/yr)	Max Hrly. Cl2 Emissions (lb/hr)	Normal Annual Cl2 Emissions (lb/yr)	Normal Annual CO2 Emissions (lb/yr)
KSE	1.43	0.90	11080.78	7009.07	14.92	40850.96	2.39	18590.00	0.00	0.00	
BH1	0.0017	0.0000	9.4050	0.1426							
BH2	0.0873	0.0013	181.0079	2.7437	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
BH3	0.0172	0.0003	33.5654	0.5088	0.0	0.0	0.0	0.0	0.0	0.0	
CS	0.36	0.36	1960.20	1960.20	0.00	0.00	0.0	0.0	0.0	0.0	
GBE 1-6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.45	1191.4	
S19-S26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.45	1441.4	
S31	1.8	1.1	13808.4	8734.4	0.0	0.0	3.0	23166.0	0.0	0.0	
Process CO2	-	-	-	-	-	-	-	-	-	-	52,000,441
Totals	**3.7**	**2.4**	**27,073.3**	**17,707.1**	**14.9**	**40,851.0**	**5.4**	**41,756.0**	**12.9**	**2632.8**	**52,000,441**

Footnotes for Table 5-9 - Estimated Emissions From Process Operations

[1]KSE = Kiln Stack Exhaust; BH1 = Baghouse #1; BH2 = Baghouse #2; BH3 = Baghouse #3; CS = Cyclone Stack; GBE = Germination Bed Exhaust w/ three exhaust points (GBE 1&4, GBE 2&5, GBE 3&6). Emissions calculated are total for all exhaust points.

[2]The Malt House Kilning emission factor for VOCs was developed from kiln source tests conducted at GWM's Vancouver, Washington facility on August 25, 1994. Source test data is provided in the appendices. Information from the source test indicates that during the 16 hour test period, 357,000 pounds of green malt were processed and the VOC emissions were 23.5 pounds. The resulting emission factor is calculated as follows:

Kilning VOC Emission Factor = (23.5 lb VOC / 357,000 lb malt) * (2000 lb/ton) = 0.13 lb VOC / ton Malt

PM emissions were developed using the October 14, 2005 source test at GWM Pocatello plant which indicates a filterable PM emission of 0.95 lb/hr equating to a filterable PM emission rate of 0.057 lb/T. In AP-42, Section 9.9, Table 9.9.1-2, Gas Fired Malt Kiln, the filterable PM is 68.3% of the total PM emission factor (0.19/(0.19+0.088)=0.683). Assuming the Pocatello kiln had the same ratio of filterable to total PM emission as in AP42, the resulting total (filterable + condensable) kiln PM emission factor is the filterable test result divided by 68.3% (0.057/0.683) or 0.0835 lb/T. A PM10 fraction of 92.8% and a PM2.5 fraction of 58.7% were developed from emission information presented in AP-42, Section 9.9, Table 9.9.1-2, Gas Fired Malt Kiln.

SO2 emission factors for malt house kilning sulfur combustion were developed from a source test conducted at GWM's Los Angeles, California facility. Source test data are provided in the appendices. The data indicate a maximum SO2 emission rate of 1.492 lbs SO2 / lb S or 2984 lbs SO2 / T S.

[3]The cleaning emission factors were taken from AP-42 Section 9.9.1. The section identifies a PM, PM10 and PM2.5 emission factors (lb/ton) as 0.075, 0.019, and 0.0032 respectively. The emission factors include the use of a cyclone and because cyclones are not used on these processes at GWM the emission factors were adjusted by assuming the cyclone had a control efficiency of 70%.

[4]Source testing was conducted on the Pellet Mill Cooler cyclone exhaust on April 27, 2000. The source testing revealed and emission rate of 0.066 lb PM10 / ton throughput. For these calculations it is assumed that PM2.5 is 100% of PM10. These emission factors include the presence of the cyclone and no further removal efficiency is provided in the calculation.

[5]The calculation conservatively assumes 100% volatilization of chlorine contained in the solid Sodium Hypochlorite:

Solid Sodium Hypochlorite emission factor = (35.45 lbCl/lb-mol)/(74.45lbNaOCl/lb-mol)(2000lb/T) = 960 lb Cl- / T solid NaOCl. Two molecules of Cl- per Cl2 equates to 960/2 = 480 lb Cl2/T solid NaOCl. Cleaning emissions occur over a 2-hr period.

[6]The calculation conservatively assumes 100% volatilization of chlorine contained in the 1.5 % solution of liquid Sodium Hypochlorite:

Liquid Sodium Hypochlorite emission factor = 0.015 * (35.45 lbCl/lb-mol)/(74.45lbNaOCl/lb-mol)(2000lb/T) = 14.4 lb Cl- / T liquid NaOCl. Two molecules of Cl- per CL2 equates to14.4/2 = 7.2 lb Cl2/T liquid NaOCl. Cleaning emissions occur over a 2-hr period.

[7]Initial malt cleaning occurs before storage with emissions controlled by BH2. Malt is cleaned again prior to shipment with emission controlled by BH3. Emission estimates assume 67% of malt cleaning emissions are vented to BH2 and 33% are vented to BH3

[8] CO2 is generated during the malting processes, mainly steeping. In the GWM process there is about a 5% loss of dry matter per MT of malt produced. Dry matter is essentially glucose (MW 180). Each molecule of glucose produces 6 molecules of CO2 or 1.47 kg of CO2 per kg of dry matter lost. 50 kg loss/MT malt X 1.47 kg CO2/kg loss = 73.5 kg CO2 produced/MT malt. converting to pounds yields: (73.5 kg/MT malt) X (1000 g/kg)/(454 g/lb) = 161.89 lb CO2/MT malt.

Table 5-10
Estimated Emissions from Fuel Burning Equipment

Emission Factors

Source	Stack ID	Emission Factor Reference	Units		PM10	PM2.5	SO2	CO	NOx	VOC	CO2e	
		Emission Factor										
Malt House Boilers 1&2	BS1	AP-42 Section 1.4 (7/98), Uncontrolled small boilers,	lb/MMCF		7.6	7.6	0.6	84	100	5.5	120,035	
Pellet Mill Boiler	BS2											
Germination Vessel boilers-6	S38-S43	AP-42 Section 1.4 (7/98) and manufacturer information	lb/MMCF		7.6	7.6	0.6	84	30	5.5	120,035	Vendor certifies NOx at <20 ppm
Kiln1 burners (K1-K10)	KS1-KS5	AP-42 Section 1.4 (7/98) and manufacturer information	lb/MMCF		7.6	7.6	0.6	227	37	5.5	120,035	Vendor certifies NOx at <0.036 lb/MM Btu and CO at <0.221 lb/MM Btu
Kiln2 burners (KB1-KB4)	S27-S30	AP-42 Section 1.4 (7/98) and manufacturer information	lb/MMCF		7.6	7.6	0.6	227	37	5.5	120,035	Vendor certifies NOx at <0.036 lb/MM Btu and CO at <0.221 lb/MM Btu
Makeup Air Units	S44-S45	AP-42 Section 1.4 (7/98), Uncontrolled small boilers	lb/MMCF		7.6	7.6	0.6	84	100	5.5	120,035	
Emergency Generator (60 hp)	EG	AP-42 Section 3.3 (10/96) Diesel Industrial Engines	lb/hp-hr		0.0022	0.0022	0.000205	0.00668	0.031	0.00247	1.15	

Estimated Maximum Hourly Emissions

Source	Stack ID	Maximum Hourly Usage (Natural Gas MMCF) (Diesel hours)	PM10	PM2.5	SO2	CO	NOx	VOC		CO2e	
			Estimated Max Hourly Emissions (lb/hr)								
Kiln 1 Burner K1	KS1	0.00775	0.0589	0.0589	0.005	1.758	0.29	0.043		929.7	
Kiln 1 Burners K2 -K5	KS2	0.03098	0.2355	0.2355	0.019	7.033	1.15	0.170		3,718.7	
Kiln 1 Burner K6	KS3	0.00775	0.0589	0.0589	0.005	1.758	0.29	0.043		929.7	
Kiln 1 Burners K7 - K9	KS4	0.02324	0.1766	0.1766	0.014	5.274	0.86	0.128		2,789.0	
Kiln 1 Burner K10	KS5	0.00775	0.0589	0.0589	0.005	1.758	0.29	0.043		929.7	
Malt House Boilers 1&2[1]	BS1	0.00625	0.0475	0.0475	0.00375	0.525	0.625	0.034		750.2	Only one boiler at time at 25% of capacity.
Pellet Mill Boiler	BS2	0.0025	0.019	0.019	0.0015	0.21	0.25	0.014		300.1	
GV boiler 1 (GVB1)[2]	S38	0.002	0.0152	0.0152	0.0012	0.168	0.06	0.011		240.1	
GV boiler 2 (GVB2)	S39	0.002	0.0152	0.0152	0.0012	0.168	0.06	0.011		240.1	
GV boiler 3 (GVB3)	S40	backup									
GV boiler 4 (GVB4)	S41	0.002	0.0152	0.0152	0.0012	0.168	0.06	0.011		240.1	
GV boiler 5 (GVB5)	S42	0.002	0.0152	0.0152	0.0012	0.168	0.06	0.011		240.1	
GV boiler 6 (GVB6)	S43	backup									
Kiln 2 Burner 1 (KB1)	S27	0.0177	0.13452	0.13452	0.01062	4.0179	0.6549	0.09735		2,124.6	
Kiln 2 Burner 2 (KB2)	S28	0.0177	0.13452	0.13452	0.01062	4.0179	0.6549	0.09735		2,124.6	
Kiln 2 Burner 3 (KB3)	S29	0.0177	0.13452	0.13452	0.01062	4.0179	0.6549	0.09735		2,124.6	
Kiln 2 Burner 4 (KB4)	S30	0.0177	0.13452	0.13452	0.01062	4.0179	0.6549	0.09735		2,124.6	
Steep Blg. Makeup Air Unit 1 (MAU1)	S44	0.002188	0.0166288	0.01663	0.0013128	0.183792	0.2188	0.012034		262.6	
Steep Blg. Makeup Air Unit 2 (MAU2)	S45	0.002188	0.0166288	0.01663	0.0013128	0.183792	0.2188	0.012034		262.6	
Emergency Generator (EG1)-diesel	EG	1	0.132	0.132	0.0123	0.4008	1.86	0.1482		69.0	
		Totals	**1.42**	**1.42**	**0.11**	**35.83**	**8.90**	**1.08**		**20,400.2**	

Table 5-10
Estimated Emissions from Fuel Burning Equipment

Estimated Normal Annual Emissions

Source	Stack ID	Maximum Annual Usage (Natural Gas MMCF) (Diesel hours)	Estimated Normal Annual Emissions (lb/yr)							
			PM10	PM2.5	SO2	CO	NOx	VOC		CO2e
Kiln 1 Burner K1	KS1	29.0	220.40	220.40	17.4	6583.0	1073.0	159.5		3,481,015
Kiln 1 Burners K2 -K5	KS2	116.0	881.60	881.60	69.6	26332.0	4292.0	638.0		13,924,060
Kiln 1 Burner K6	KS3	29.0	220.40	220.40	17.4	6583.0	1073.0	159.5		3,481,015
Kiln 1 Burners K7 - K9	KS4	87.0	661.20	661.20	52.2	19749.0	3219.0	478.5		10,443,045
Kiln 1 Burner K10	KS5	29.0	220.40	220.40	17.4	6583.0	1073.0	159.5		3,481,015
Malt House Boilers 1&2[1]	BS1	21.036	159.9	159.9	12.6	1767.0	2103.6	115.7		2,525,056
Pellet Mill Boiler	BS2	21.9	166.4	166.4	13.1	1839.6	2190.0	120.5		2,628,767
GV boiler 1 (GVB1)[2]	S38	17.52	133.2	133.2	10.5	1471.7	525.6	96.4		2,103,013
GV boiler 2 (GVB2)	S39	17.52	133.2	133.2	10.5	1471.7	525.6	96.4		2,103,013
GV boiler 3 (GVB3)	S40	backup								
GV boiler 4 (GVB4)	S41	17.52	133.2	133.2	10.5	1471.7	525.6	96.4		2,103,013
GV boiler 5 (GVB5)	S42	17.52	133.2	133.2	10.5	1471.7	525.6	96.4		2,103,013
GV boiler 6 (GVB6)	S43	backup								
Kiln 2 Burner 1 (KB1)	S27	105.00	798.0	798.0	63.0	23835.0	3885.0	577.5		12,603,675
Kiln 2 Burner 2 (KB2)	S28	105.00	798.0	798.0	63.0	23835.0	3885.0	577.5		12,603,675
Kiln 2 Burner 3 (KB3)	S29	105.00	798.0	798.0	63.0	23835.0	3885.0	577.5		12,603,675
Kiln 2 Burner 4 (KB4)	S30	105.00	798.0	798.0	63.0	23835.0	3885.0	577.5		12,603,675
Steep Blg. Makeup Air Unit 1 (MAU1)	S44	19.17	145.7	145.7	11.5	1610.0	1916.7	105.4		2,300,696
Steep Blg. Makeup Air Unit 2 (MAU2)	S45	19.17	145.7	145.7	11.5	1610.0	1916.7	105.4		2,300,696
Emergency Generator (EG1)-diesel	EG	100	13.2	13.2	1.2	40.1	186.0	14.8		6,900
		Totals (lb/yr)	**6,559.5**	**6,559.5**	**518.0**	**173,923.5**	**36,685.4**	**4,752.2**		**103,399,018**
		Totals (tons/yr)	**3.28**	**3.28**	**0.26**	**86.96**	**18.34**	**2.38**		**51,700**

Footnotes:

[1] The malt house boilers are vented to a common stack. Only one boiler operates at a time. Hourly fuel use assumes 25% of one boiler capacity.

[2] GVB1-GVB3 serve GV1 and GV2. GVB4-GVB6 serve GV3 and GV4. Only 4 boilers will run at a time with the remaining 2 boilers as backup.

Table 5-11
HAP and TAP Emissions from Natural Gas Combustion in Malthouse Boilers

Component	Rate		CAS	Substance	Emission Factor	Emissions		
	MMCF/hr	MMCF/yr			(lb/MMCF)[1]	lb/hr	ton/yr	lb/hr annual
MALT HOUSE BOILERS 1 & 2	0.00625	21.036	75070	Acetaldehyde	4.30E-03	2.69E-05	4.52E-05	1.03E-05
			107028	Acrolein	2.70E-03	1.69E-05	2.84E-05	6.48E-06
			71432	Benzene	8.00E-03	5.00E-05	8.41E-05	1.92E-05
			100414	Ethyl Benzene	9.50E-03	5.94E-05	9.99E-05	2.28E-05
			50000	Formaldehyde	1.70E-02	1.06E-04	1.79E-04	4.08E-05
			110543	Hexane	6.30E-03	3.94E-05	6.63E-05	1.51E-05
			91203	Naphthalene	3.00E-04	1.88E-06	3.16E-06	7.20E-07
			1151	PAH's (including naphthalene)	4.00E-04	2.50E-06	4.21E-06	9.61E-07
			108883	Toluene	3.66E-02	2.29E-04	3.85E-04	8.79E-05
			1330207	Xylenes	2.72E-02	1.70E-04	2.86E-04	6.53E-05
					Total	7.02E-04	1.18E-03	2.70E-04

[1]MMCF = Million Cubic Feet; Emission Factors from "Natural Gas Fired External Combustion Equipment", VCAPCD AB2588 Combustion Emission Factors and SJVAPCD Toxic Emission Factors (www.valley.org/busind/pto/emission_factors/emission_factors_idx.htm).

Table 5-12
HAP and TAP Emissions
from Natural Gas Combustion Pellet Mill Boiler

Component	Rate		CAS	Substance	Emission Factor (lb/MMCF)[1]	Emissions		
	MMCF/hr	MMCF/yr				lb/hr	ton/yr	Annual lb/hr
PELLET MILL BOILER	0.0025	21.9	75070	Acetaldehyde	4.30E-03	1.08E-05	4.71E-05	1.08E-05
			107028	Acrolein	2.70E-03	6.75E-06	2.96E-05	6.75E-06
			71432	Benzene	8.00E-03	2.00E-05	8.76E-05	2.00E-05
			100414	Ethyl Benzene	9.50E-03	2.38E-05	1.04E-04	2.38E-05
			50000	Formaldehyde	1.70E-02	4.25E-05	1.86E-04	4.25E-05
			110543	Hexane	6.30E-03	1.58E-05	6.90E-05	1.58E-05
			91203	Naphthalene	3.00E-04	7.50E-07	3.29E-06	7.50E-07
			1151	PAH's (including naphthalene)	4.00E-04	1.00E-06	4.38E-06	1.00E-06
			108883	Toluene	3.66E-02	9.15E-05	4.01E-04	9.15E-05
			1330207	Xylenes	2.72E-02	6.80E-05	2.98E-04	6.80E-05
					Total	2.81E-04	1.23E-03	2.81E-04

[1]MMCF = Million Cubic Feet; Emission Factors from "Natural Gas Fired External Combustion Equipment", VCAPCD AB2588 Combustion Emission Factors and SJVAPCD Toxic Emission Factors (www.valley.org/busind/pto/emission_factors/emission_factors_idx.htm).

Table 5-13
HAP and TAP Emissions
from Natural Gas Combustion in the Malthouse Kiln New Heaters

Component	Rate MMCF/hr	Rate MMCF/yr	CAS	Substance	Emission Factor (lb/MMCF)[1]	Emissions lb/hr	Emissions ton/yr	Emissions Annual lb/hr
KILN 1 NEW HEATERS	0.0775	290	75070	Acetaldehyde	4.30E-03	3.33E-04	6.24E-04	1.42E-04
			107028	Acrolein	2.70E-03	2.09E-04	3.92E-04	8.94E-05
			71432	Benzene	8.00E-03	6.20E-04	1.16E-03	2.65E-04
			100414	Ethyl Benzene	9.50E-03	7.36E-04	1.38E-03	3.14E-04
			50000	Formaldehyde	1.70E-02	1.32E-03	2.47E-03	5.63E-04
			110543	Hexane	6.30E-03	4.88E-04	9.14E-04	2.09E-04
			91203	Naphthalene	3.00E-04	2.32E-05	4.35E-05	9.93E-06
			1151	PAH's (including naphthalene)	4.00E-04	3.10E-05	5.80E-05	1.32E-05
			108883	Toluene	3.66E-02	2.83E-03	5.31E-03	1.21E-03
			1330207	Xylenes	2.72E-02	2.11E-03	3.94E-03	9.00E-04
					Total	8.70E-03	1.63E-02	3.72E-03

[1]MMCF = Million Cubic Feet; Emission Factors from "Natural Gas Fired External Combustion Equipment", VCAPCD AB2588 Combustion Emission Factors and SJVAPCD Toxic Emission Factors (www.valley.org/busind/pto/emission_factors/emission_factors_idx.htm).

Table 5-14
HAP and TAP Emissions from Natural Gas Combustion in Six New Germination Boilers

Component	Rate		CAS	Substance	Emission Factor	Emissions		
	MMCF/hr	MMCF/yr			(lb/MMCF)[1]	lb/hr	ton/yr	Annual lb/hr
6 new boilers	0.0080	70.08	75070	Acetaldehyde	4.30E-03	3.44E-05	1.51E-04	3.44E-05
			107028	Acrolein	2.70E-03	2.16E-05	9.46E-05	2.16E-05
			71432	Benzene	8.00E-03	6.40E-05	2.80E-04	6.40E-05
			100414	Ethyl Benzene	9.50E-03	7.60E-05	3.33E-04	7.60E-05
			50000	Formaldehyde	1.70E-02	1.36E-04	5.96E-04	1.36E-04
			110543	Hexane	6.30E-03	5.04E-05	2.21E-04	5.04E-05
			91203	Naphthalene	3.00E-04	2.40E-06	1.05E-05	2.40E-06
			1151	PAH's (including naphthalene)	4.00E-04	3.20E-06	1.40E-05	3.20E-06
			108883	Toluene	3.66E-02	2.93E-04	1.28E-03	2.93E-04
			1330207	Xylenes	2.72E-02	2.18E-04	9.53E-04	2.18E-04
					Total	8.98E-04	3.93E-03	8.98E-04

[1]MMCF = Million Cubic Feet; Emission Factors from "Natural Gas Fired External Combustion Equipment", VCAPCD AB2588 Combustion Emission Factors and SJVAPCD Toxic Emission Factors (www.valley.org/busind/pto/emission_factors/emission_factors_idx.htm).

Table 5-15
HAP and TAP Emissions from Natural Gas Combustion in New Kiln Burners

Component	Rate		CAS	Substance	Emission Factor	Emissions		
	MMCF/hr	MMCF/yr			(lb/MMCF)[1]	lb/hr	ton/yr	Annual lb/hr
New KILN 2 BURNERS	0.0708	420	75070	Acetaldehyde	4.30E-03	3.04E-04	9.03E-04	2.06E-04
			107028	Acrolein	2.70E-03	1.91E-04	5.67E-04	1.29E-04
			71432	Benzene	8.00E-03	5.66E-04	1.68E-03	3.84E-04
			100414	Ethyl Benzene	9.50E-03	6.73E-04	2.00E-03	4.55E-04
			50000	Formaldehyde	1.70E-02	1.20E-03	3.57E-03	8.15E-04
			110543	Hexane	6.30E-03	4.46E-04	1.32E-03	3.02E-04
			91203	Naphthalene	3.00E-04	2.12E-05	6.30E-05	1.44E-05
			1151	PAH's (including naphthalene)	4.00E-04	2.83E-05	8.40E-05	1.92E-05
			108883	Toluene	3.66E-02	2.59E-03	7.69E-03	1.75E-03
			1330207	Xylenes	2.72E-02	1.93E-03	5.71E-03	1.30E-03
					Total	7.95E-03	2.36E-02	5.38E-03

[1]MMCF = Million Cubic Feet; Emission Factors from "Natural Gas Fired External Combustion Equipment", VCAPCD AB2588 Combustion Emission Factors and SJVAPCD Toxic Emission Factors (www.valley.org/busind/pto/emission_factors/emission_factors_idx.htm).

Table 5-16
HAP and TAP Emissions from Natural Gas Combustion in Steep Makeup Air Heaters

Component	Rate		CAS	Substance	Emission Factor	Emissions		
	MMCF/hr	MMCF/yr			(lb/MMCF)[1]	lb/hr	ton/yr	Annual lb/hr
Makeup Air Units MAU1 & MAU2	0.0044	38.3338	75070	Acetaldehyde	4.30E-03	1.88E-05	8.24E-05	1.88E-05
			107028	Acrolein	2.70E-03	1.18E-05	5.18E-05	1.18E-05
			71432	Benzene	8.00E-03	3.50E-05	1.53E-04	3.50E-05
			100414	Ethyl Benzene	9.50E-03	4.16E-05	1.82E-04	4.16E-05
			50000	Formaldehyde	1.70E-02	7.44E-05	3.26E-04	7.44E-05
			110543	Hexane	6.30E-03	2.76E-05	1.21E-04	2.76E-05
			91203	Naphthalene	3.00E-04	1.31E-06	5.75E-06	1.31E-06
			1151	PAH's (including naphthalene)	4.00E-04	1.75E-06	7.67E-06	1.75E-06
			108883	Toluene	3.66E-02	1.60E-04	7.02E-04	1.60E-04
			1330207	Xylenes	2.72E-02	1.19E-04	5.21E-04	1.19E-04
					Total	4.91E-04	2.15E-03	4.91E-04

[1]MMCF = Million Cubic Feet; Emission Factors from "Natural Gas Fired External Combustion Equipment", VCAPCD AB2588 Combustion Emission Factors and SJVAPCD Toxic Emission Factors (www.valley.org/busind/pto/emission_factors/emission_factors_idx.htm).

Table 5-17
Pre-Project Emissions from Material Handling Operations

Process Step	Emission Point[2]	Max. Hrly. Transfer Rate (MT/hr.)	Normal Hrly. Transfer Rate (MT/hr.)	Normal Annual Transfer Rate (MT/yr.)	Control Efficiency (%)[7]	Uncontrolled PM Emission Factor (lb/ton)	Uncontrolled PM10 Emission Factor (lb/ton)	Uncontrolled PM2.5 Emission Factor (lb/ton)	Emission Factor Reference	Max. Hrly. PM10 Emissions (lb/hr)	Max. Hrly. PM2.5 Emissions (lb/hr)	Normal Annual PM10 Emissions (lb/yr)	Normal Annual PM2.5 Emissions (lb/yr)
Truck Barley Unload - Uncaptured[1]	TB	150	25.64	109,091	0%	0.0025	0.00065	0.00011	AP-42 Table 9.9.1-1 (3/03)	0.11	0.02	77.5	13.0
Truck Barley Unload - Stack	BH1	150	25.64	109,091	99.50%	0.047	0.012	0.0021	AP-42 Table 9.9.1-1 (3/03)	0.01	0.002	7.4	1.2
Rail Barley Unload - Uncaptured	RB	150	25.64	46,364	0%	0.0016	0.00039	0.000065	AP-42 Table 9.9.1-1 (3/03)	0.06	0.01	19.9	3.3
Rail Barley Unload - Stack	BH1	150	25.64	46,364	99.50%	0.030	0.0074	0.0012	AP-42 Table 9.9.1-1 (3/03)	0.01	0.001	1.9	0.3
Barley Headhouse Transfers	BH1 & BH2	150	150	331,000	99.50%	0.061	0.034	0.0058	AP-42 Table 9.9.1-1 (3/03)	0.03	0.00	61.9	10.6
Barley Transfers Before Cleaning	BH2	150	150	177,000	99.50%	0.061	0.034	0.0058	AP-42 Table 9.9.1-1 (3/03)	0.03	0.00	33.1	5.6
Barley Transfers After Cleaning	BH2	150	150	177,000	99.50%	0.061	0.034	0.0058	AP-42 Table 9.9.1-1 (3/03)	0.03	0.00	33.1	5.6
Feed Barley Transfer to Bins	BH1	150	150	9400	99.50%	0.061	0.034	0.0058	AP-42 Table 9.9.1-1 (3/03)	0.03	0.00	1.8	0.3
Feed Barley Loading for Shipment - Uncaptured[6]	TB	400	400	9,400	0%	0.0043	0.0015	0.00025	AP-42 Table 9.9.1-1 (3/03)	0.64	0.11	15.0	2.5
Feed Barley Loading for Shipment - Stack	BH3	400	400	9,400	99.50%	0.082	0.028	0.00466	AP-42 Table 9.9.1-1 (3/03)	0.06	0.01	1.4	0.2
Pellet Mill Transfers	BH1	5	5	11,273	99.50%	0.061	0.034	0.0058	AP-42 Table 9.9.1-1 (3/03)	0.00	0.00	2.1	0.4
Truck Pellet Loading for Shipment[3]	TB	6	6	3382	0%	0.0033	0.0008	0.00056	AP-42 Table 9.9.1-2 (3/03)	0.01	0.00	3.0	2.1
Rail Pellet Loading for Shipment	RB	6	6	7,891	0%	0.0033	0.0008	0.00056	AP-42 Table 9.9.1-2 (3/03)	0.01	0.00	6.9	4.9
Malt Transfers	BH1 & BH3	150	75	118,182	99.50%	0.061	0.034	0.0058	AP-42 Table 9.9.1-1 (3/03)	0.03	0.00	22.1	3.8
Rail Malt Loading for Shipment[4]	RB	180	180	23,636	0%	0.027	0.0022	0.00037	AP-42 Table 9.9.1-1 (3/03)	0.44	0.07	57.2	9.6
Truck Malt Loading for Shipment	TB	20	20	94,546	0%	0.086	0.029	0.0049	AP-42 Table 9.9.1-1 (3/03)	0.64	0.11	3016.0	509.6
									Total	**2.1**	**0.36**	**3360**	**573**

Emission Point Summary for Material Handling Processes[5]

Emission Point	Max. Hrly. PM Emissions (lb/hr)	Normal Hrly. PM Emissions (lb/hr)	Normal Annual PM Emissions (lb/yr)	Max. Hrly. PM10 Emissions (lb/hr)	Max. Hrly. PM2.5 Emissions (lb/hr)	Normal Annual PM10 Emissions (lb/yr)	Normal Annual PM2.5 Emissions (lb/yr)
TB	4.21	3.88	9297.8	1.39	0.24	3111.5	527.2
RB	5.63	5.41	812.2	0.51	0.09	84.0	17.8
BH1	0.17	0.108	139.7	0.073	0.012	67.1	11.4
BH2	0.11	0.11	141.0	0.062	0.011	78.6	13.4
BH3	0.22	0.20	35.9	0.083	0.014	19.1	3.3
Totals	**10.3**	**9.7**	**10,426.6**	**2.1**	**0.4**	**3,360.3**	**573.1**

Footnotes for Table 5-17 - Pre-Project Emissions From Material Handling Operations

[1]The emission factors for truck unloading assumes 90% hopper trucks and 10% straight trucks and is weighted per EPA AP-42 guidance. In addition, because the truck unloading pit is vented to BH1 it is assumed that 5% of the generated emission become airborne as fugitive emissions. For example the PM emission factor is calculated as follows:

Truck Unloading Emission Factor = [(0.90)(0.035 lb/ton) + (0.10)(0.18 lb/ton)]0.05 = 0.0025 lb/ton

The railbay unloading operation is also vented to BH1. A 95% capture efficiency is also applied to the AP-42 emission factors.

[2]TB = Truck Bay; RB = Rail Bay; BH1 = Baghouse #1; BH2 = Baghouse #2; BH3 = Baghouse #3

[3]The PM2.5 emission factor for truck & rail pellet loading for shipment assumes the PM2.5 fraction is 17% of PM.

[4] It is assumed that malt loadout occurs 90% by rail and 10% by truck.

[5] Headhouse transfer and malt transfer operations are served by multiple baghouses. Emission estimates assume 80% of barley headhouse transfer emissions are vented to BH1 and 20% are vented to BH2. 80% of malt transfer emissions are vented to BH3 and 20% to BH1.

[6]Feed barley loadout operations are equipped with a cyclone side draw vacuum system which vents to BH3. A 95% capture efficiency is applied to the AP-42 emission factors with the remaining 5% assumed to be available to become airborne fugitive emissions.

[7]Control efficiency estimated from USEPA Air Pollution Control Technology Fact Sheet for Fabric Filters (EPA-452/F-03-024). This document indicates operating efficiencies of 95-99.9%. Us 99.5% for existing baghouses.

Table 5-18
Pre-Project Emissions from Process Operations

Process Step	Emission Point[1]	Max/Normal Hrly. Transfer Rate (MT/hr.)	Normal Annual Transfer Rate (MT/yr.)	Control Efficiency (%)	PM Emission Factor (lb/ton)	PM10 Emission Factor (lb/ton)	PM2.5 Emission Factor (lb/ton)	SO2 Emission Factor (lb/T S)	VOC Emission Factor (lb/ton)	Cl2 Emission Factor (lb/T hypochlorite)	CO2 Emission Factor (lb/ton malt)	Emission Factor Reference	Max/Normal Hrly. PM10 Emissions (lb/hr)	Max/Normal Hrly. PM2.5 Emissions (lb/hr)	Normal Annual PM10 Emissions (lb/yr)	Normal Annual PM2.5 Emissions (lb/yr)	Max Hrly. SO2 Emissions (lb/hr)	Normal Annual SO2 Emissions (lb/yr)	Max Hrly. VOC Emissions (lb/hr)	Normal Annual VOC Emissions (lb/yr)	Max Hrly. Cl2 Emissions (lb/hr)	Normal Annual Cl2 Emissions (lb/yr)	Normal Annual CO2 Emissions (lb/yr)
Malt House Kilning	KSE	16.73	118,182	0%	0.0835	0.0775	0.0490	0.0	0.13	0.0		Source Test[2]	1.43	0.90	10073.4	6368.5	0.0	0.0	2.39	16900.0	0.0	0.0	0
Malt House Kilning Sulfur Combustion	KSE	0.0045	12.45	0%	0	0	0	2984	0	0		Source Test[2]	0.00	0.00	0.0	0.0	14.9	40851.0	0.00	0.0	0.0	0.0	0
Barley Cleaning	BH2	150	177,000	99.50%	0.25	0.063	0.00096	0	0	0		AP-42 Table 9.9.1-1 (3/03)[3]	0.05	0.00	61.7	0.9	0.0	0.0	0.00	0.0	0.0	0.0	0
Malt Cleaning	BH2 & BH3	150	118,182	99.50%	0.25	0.063	0.00096	0	0	0		AP-42 Table 9.9.1-1 (3/03)[3]	0.05	0.00	41.2	0.6	0.0	0.0	0.00	0.0	0.0	0.0	0
Pellet Mill Cleaning	BH1	4.55	11,273	99.50%	0.25	0.063	0.00096	0	0	0		AP-42 Table 9.9.1-1 (3/03)[3]	0.00	0.00	3.9	0.1	0.0	0.0	0.00	0.0	0.0	0.0	0
Pellet Mill Cooler	CS	4.55	11,273	0%	0.132	0.066	0.066	0	0	0		Source Test[4]	0.33	0.33	818.4	818.4	0.0	0.0	0.00	0.0	0.0	0.0	0
Germination Bed Sanitizing, Solid NaOCl	GBE 1-6	0.023	0.45	0%	0	0	0	0	0	480		Mass Balance[5]	0.00	0.00	0.0	0.0	0.0	0.0	0.00	0.0	6.0	240.0	0
Germination Bed Sanitizing, Liquid NaOCl	GBE 1-6	0.114	120.12	0%	0	0	0	0	0	7.2		Mass Balance[5]	0.00	0.00	0.0	0.0	0.0	0.0	0.00	0.0	0.45	951.4	0
Process CO2[8]	Klins, steeps & germination		118,182	0%	0	0	0	0	0	0	161.89	Calculation of glucose loss from steeping & respiration	0.00	0.00	0.0	0.0	0.0	0.0	0.00	0.0	0.0	0.0	21,045,700
												Totals	**1.86**	**1.23**	**10,998.59**	**7,188.50**	**14.92**	**40,850.96**	**2.39**	**16,900.00**	**6.45**	**1,191.35**	**21,045,700**

Emission Point Summary for Process Operations[6]

Emission Point	Max/Normal Hrly. PM Emissions (lb/hr)	Normal Annual PM Emissions (lb/yr)	Max/Normal Hrly. PM10 Emissions (lb/hr)	Max/Normal Hrly. PM2.5 Emissions (lb/hr)	Normal Annual PM10 Emissions (lb/yr)	Normal Annual PM2.5 Emissions (lb/yr)	Max Hrly. SO2 Emissions (lb/hr)	Normal Annual SO2 Emissions (lb/yr)	Max Hrly. VOC Emissions (lb/hr)	Normal Annual VOC Emissions (lb/yr)	Max Hrly. Cl2 Emissions (lb/hr)	Normal Annual Cl2 Emissions (lb/yr)
KSE	1.54	10849.2	1.43	0.90	10073.4	6368.5	14.9	40851.0	2.4	16900.0	0	0
BH1	0.0063	15.5	0.0016	0.000024	3.9	0.1	0	0	0	0	0	0
BH2	0.3444	352.3	0.0873	0.0013	89.2	1.4	0	0	0	0	0	0
BH3	0.0681	53.6	0.0172	0.0003	13.6	0.2	0	0	0	0	0	0
CS	0.66	1636.8	0.33	0.33	818.4	818.4	0	0	0	0	0	0
GBE-1-6	0	0	0	0	0	0	0	0	0	0	6.5	1191.4
Process CO2	-	-	-	-	-	-	-	-	-	-	-	-
Totals	**2.6**	**12,907.4**	**1.9**	**1.2**	**10,998.6**	**7,188.5**	**14.9**	**40,851.0**	**2.4**	**16,900.0**	**6.45**	**1191.4**

Footnotes for Table 5-18 - Estimated Emissions From Process Operations

[1]KSE = Kiln Stack Exhaust; BH1 = Baghouse #1; BH2 = Baghouse #2; BH3 = Baghouse #3; CS = Cyclone Stack; GBE = Germination Bed Exhaust w/ three exhaust points (GBE 1&4, GBE 2&5, GBE 3&6). Emissions calculated are total for all exhaust points.

[2]The Malt House Kilning emission factor for VOCs was developed from kiln source tests conducted at GWM's Vancouver, Washington facility on August 25, 1994. Source test data is provided in the appendices. Information from the source test indicates that during the 16 hour test period, 357,000 pounds of green malt were processed and the VOC emissions were 23.5 pounds. The resulting emission factor is calculated as follows:

Kilning VOC Emission Factor = (23.5 lb VOC / 357,000 lb malt) * (2000 lb/ton) = 0.13 lb VOC / ton Malt

PM emissions were developed using the October 14, 2005 source test at GWM Pocatello plant which indicates a filterable PM emission of 0.95 lb/hr equating to a filterable PM emission rate of 0.057 lb/T. In AP-42, Section 9.9, Table 9.9.1-2, Gas Fired Malt Kiln, the filterable PM is 68.3% of the total PM emission factor (0.19/(0.19+0.088)=0.683). Assuming the Pocatello kiln had the same ratio of filterable to total PM emission as in AP42, the resulting total (filterable + condensible) kiln PM emission factor is the filterable test result divided by 68.3% (0.057/0.683) or 0.0835 lb/T. A PM10 fraction of 92.8% and a PM2.5 fraction of 58.7% were developed from emission information presented in AP-42, Section 9.9, Table 9.9.1-2, Gas Fired Malt Kiln.

SO2 emission factors for malt house kilning sulfur combustion were developed from a source test conducted at GWM's Los Angeles, California facility. Source test data is provided in the appendices. The data indicates a maximum SO2 emission rate of 1.492 lbs SO2 / lb S or 2984 lbs SO2 / T S.

[3]The cleaning emission factors were taken from AP-42 Section 9.9.1. The section identifies a PM, PM10 and PM2.5 emission factors (lb/ton) as 0.075, 0.019, and 0.0032 respectively. The emission factors include the use of a cyclone and because cyclones are not used on these processes at GWM the emission factors were adjusted by assuming the cyclone had a control efficiency of 70%.

[4]Source testing was conducted on the Pellet Mill Cooler cyclone exhaust on April 27, 2000. The source testing revealed and emission rate of 0.066 lb PM10 / ton throughput. AP-42 Table 9.1.1-2 for Animal Feed Mill Pelletizers indicates that the PM10 emission factor can be taken as 50% of PM. As such, the PM10 emission factor was doubled to calculate total PM.   For these calculations it is further assumed that PM2.5 is 100% of PM10. These emission factors include the presence of the cyclone and no further removal efficiency is provided in the calculation.

[5]The calculation conservatively assumes 100% volatilization of chlorine contained in the solid Sodium Hypochlorite:

Solid Sodium Hypochlorite emission factor = (35.45 lbCl/lb-mol)/(74.45lbNaOCl/lb-mol)(2000lb/T) = 960 lb Cl / T $NaOCl_{(s)}$ Two molecules of Cl- per Cl2 so divide by 2. 960/2 = 480 lb Cl2/T NaOCl.

[6]The calculation conservatively assumes 100% volatilization of chlorine contained in the 1.5 % solution of liquid Sodium Hypochlorite:

Liquid Sodium Hypochlorite emission factor = 0.015 * (35.45 lbCl/lb-mol)/(74.45lbNaOCl/lb-mol)(2000lb/T) = 14.4 lb Cl / T $NaOCl_{(l)}$ Two molecules of Cl- per CL2 so divide by 2. 14.4/2 = 7.2 lb Cl2/T NaOCl

[7]Initial malt cleaning occurs before storage with emissions controlled by BH2. Malt is cleaned again prior to shipment with emission controlled by BH3. Emission estimates assume 67% of malt cleaning emissions are vented to BH2 and 33% are vented to BH3

[8] CO2 is generated during the malting processes, mainly steeping. In the GWM process there is about a 5% loss of dry matter per MT of malt produced. Dry matter is essentially glucose (MW 180). Each molecule of glucose produces 6 molecules of CO2 or 1.47 kg of CO2 per kg of dry matter lost. 50 kg loss/MT malt X 1.47 kg CO2/kg loss = 73.5 kg CO2 produced/MT malt. converting to pounds yields: (73.5 kg/MT malt) X (1000 g/kg)/(454 g/lb) = 161.89 lb CO2/MT malt.

Table 5-19
Pre-Project Emissions from Fuel Burning Equipment

Emission Factors

Source	Stack ID	Emission Factor (lb/MMCF)							
		Emission Factor Reference	PM10	PM2.5	SO2	CO	NOx	VOC	CO2e
Kiln Burners	KS1-KS5	AP-42 Section 1.4 (7/98), Uncontrolled small boilers	7.6	7.6	0.6	84	100	5.5	120,035
Malt House Boilers 1&2	BS1								
Pellet Mill Boiler	BS2								

Estimated Maximum Hourly Emissions

Source	Stack ID	Maximum Hourly Natural Gas Usage (MMCF/hr)	Estimated Max Hourly Emissions (lb/hr)						
			PM10	PM2.5	SO2	CO	NOx	VOC	CO2e
Kiln Burner #1	KS1	0.0069	0.05	0.05	0.004	0.58	0.69	0.04	828.24
Kiln Burner #2 -#5	KS2	0.0276	0.21	0.21	0.017	2.32	2.76	0.15	3312.97
Kiln Burner #6	KS3	0.0069	0.05	0.05	0.004	0.58	0.69	0.04	828.24
Kiln Burner #7 - #9	KS4	0.0207	0.16	0.16	0.012	1.74	2.07	0.11	2484.72
Kiln Burner #10	KS5	0.0069	0.05	0.05	0.004	0.58	0.69	0.04	828.24
Malt House Boilers 1&2[2]	BS1	0.05	0.38	0.38	0.03	4.2	5	0.28	6001.75
Pellet Mill Boiler	BS2	0.0025	0.019	0.019	0.0015	0.21	0.25	0.014	300.09
		Totals	**0.92**	**0.92**	**0.07**	**10.21**	**12.15**	**0.67**	**14,584**

Estimated Normal Annual Emissions

Source	Stack ID	Normal Annual Natural Gas Usage (MMCF/yr)	Estimated Normal Annual Emissions (lb/yr)						
			PM10	PM2.5	SO2	CO	NOx	VOC	CO2e
Kiln Burner #1	KS1	31.0	235.77	235.77	18.6	2605.9	3102.2	170.6	3,723,774
Kiln Burners #2 -#5	KS2	124.1	943.08	943.08	74.5	10423.5	12409.0	682.5	14,895,095
Kiln Burner #6	KS3	31.0	235.77	235.77	18.6	2605.9	3102.2	170.6	3,723,774
Kiln Burners #7 - #9	KS4	93.1	707.31	707.31	55.8	7817.6	9306.7	511.9	11,171,321
Kiln Burner #10	KS5	31.0	235.77	235.77	18.6	2605.9	3102.2	170.6	3,723,774
Malt House Boilers 1&2[1]	BS1	21.036	159.9	159.9	12.6	1767.0	2103.6	115.7	2,525,056
Pellet Mill Boiler	BS2	15.264	116.0	116.0	9.2	1282.2	1526.4	84.0	1,832,214
		Totals (lb/yr)	**2633.6**	**2633.6**	**207.9**	**29108.0**	**34652.4**	**1905.9**	**41,595,008**
		Totals (tons/yr)	**1.32**	**1.32**	**0.10**	**14.55**	**17.33**	**0.95**	**20,798**

Footnotes:

[1]The malt house boilers are vented to a common stack. Typically, only one boiler operates at a time. However, PTE hourly fuel use and emission rates are based on both boilers operating and normal annual emissions are based on the natural gas consummed by both boilers throughout the year.

Table 5-20
Pre-Project HAP and TAP Emissions
from Natural Gas Combustion in Malthouse Boilers

Component	Rate		CAS	Substance	Emission Factor	Emissions	
	MMCF/hr	MMCF/yr			(lb/MMCF)[1]	lb/hr	ton/yr
MALT HOUSE BOILERS 1 & 2	0.050	21.036	75070	Acetaldehyde	4.30E-03	2.15E-04	4.52E-05
			107028	Acrolein	2.70E-03	1.35E-04	2.84E-05
			71432	Benzene	8.00E-03	4.00E-04	8.41E-05
			100414	Ethyl Benzene	9.50E-03	4.75E-04	9.99E-05
			50000	Formaldehyde	1.70E-02	8.50E-04	1.79E-04
			110543	Hexane	6.30E-03	3.15E-04	6.63E-05
			91203	Naphthalene	3.00E-04	1.50E-05	3.16E-06
			1151	PAH's (including naphthalene)	4.00E-04	2.00E-05	4.21E-06
			108883	Toluene	3.66E-02	1.83E-03	3.85E-04
			1330207	Xylenes	2.72E-02	1.36E-03	2.86E-04
					Total	5.62E-03	1.18E-03

[1]MMCF = Million Cubic Feet; Emission Factors from "Natural Gas Fired External Combustion Equipment", VCAPCD AB2588 Combustion Emission Factors and SJVAPCD Toxic Emission Factors (www.valley.org/busind/pto/emission_factors/emission_factors_idx.htm).

Table 5-21
Pre-Project HAP and TAP Emissions
from Natural Gas Combustion in Pellet Mill Boiler

Component	Rate		CAS	Substance	Emission Factor	Emissions	
	MMCF/hr	MMCF/yr			(lb/MMCF)[1]	lb/hr	ton/yr
PELLET MILL BOILER	0.0025	15.264	**75070**	Acetaldehyde	4.30E-03	1.08E-05	3.28E-05
			107028	Acrolein	2.70E-03	6.75E-06	2.06E-05
			71432	Benzene	8.00E-03	2.00E-05	6.11E-05
			100414	Ethyl Benzene	9.50E-03	2.38E-05	7.25E-05
			50000	Formaldehyde	1.70E-02	4.25E-05	1.30E-04
			110543	Hexane	6.30E-03	1.58E-05	4.81E-05
			91203	Naphthalene	3.00E-04	7.50E-07	2.29E-06
			1151	PAH's (including naphthalene)	4.00E-04	1.00E-06	3.05E-06
			108883	Toluene	3.66E-02	9.15E-05	2.79E-04
			1330207	Xylenes	2.72E-02	6.80E-05	2.08E-04
					Total	2.81E-04	8.57E-04

[1]MMCF = Million Cubic Feet; Emission Factors from "Natural Gas Fired External Combustion Equipment", VCAPCD AB2588 Combustion Emission Factors and SJVAPCD Toxic Emission Factors (www.valley.org/busind/pto/emission_factors/emission_factors_idx.htm).

Table 5-22
Pre-Project HAP and TAP Emissions
from Natural Gas Combustion in the Malthouse Kiln Burners

Component	Rate		CAS	Substance	Emission Factor (lb/MMCF)[1]	Emissions	
	MMCF/hr	MMCF/yr				lb/hr	ton/yr
MALT HOUSE KILN BURNERS	0.0690	310.224	75070	Acetaldehyde	4.30E-03	2.97E-04	6.67E-04
			107028	Acrolein	2.70E-03	1.86E-04	4.19E-04
			71432	Benzene	8.00E-03	5.52E-04	1.24E-03
			100414	Ethyl Benzene	9.50E-03	6.56E-04	1.47E-03
			50000	Formaldehyde	1.70E-02	1.17E-03	2.64E-03
			110543	Hexane	6.30E-03	4.35E-04	9.77E-04
			91203	Naphthalene	3.00E-04	2.07E-05	4.65E-05
			1151	PAH's (including naphthalene)	4.00E-04	2.76E-05	6.20E-05
			108883	Toluene	3.66E-02	2.53E-03	5.68E-03
			1330207	Xylenes	2.72E-02	1.88E-03	4.22E-03
					Total	7.75E-03	1.74E-02

[1]MMCF = Million Cubic Feet; Emission Factors from "Natural Gas Fired External Combustion Equipment", VCAPCD AB2588 Combustion Emission Factors and SJVAPCD Toxic Emission Factors (www.valley.org/busind/pto/emission_factors/emission_factors_idx.htm).

5.3 Limitations on Potential to Emit

Great Western Malting is required to propose limits on emissions and operations in order to remain a synthetic minor source and to show compliance with ambient air quality standards and TAP ambient acceptable concentrations. In addition, GWM must propose monitoring that will assure that the emissions and operations limits are being met. Following are the proposed limits and monitoring for the expansion project.

5.3.1 Emission Limits

Table 5-23: Proposed Limits on PM10 and PM2.5 Emissions

Stack Description	PM10		PM2.5	
	lb/hr*	Ton/yr**	lb/hr*	Ton/yr**
BH-1 Barley Headhouse	0.08	0.07	0.01	0.01
BH-2 Malt and Barley Cleaning	0.15	0.16	0.01	0.014
BH-3 Malt Cleaning, Loading & Transfer	0.10	0.04	0.014	0.004
KSE- Malthouse Kiln 1	1.43	5.54	0.90	3.51
KS1- Malthouse Kiln Burner 1	0.06	0.11	0.06	0.11
KS2- Malthouse Kiln Burners 2-5	0.24	0.44	0.24	0.44
KS3- Malthouse Kiln Burner 6	0.06	0.11	0.06	0.11
KS4- Malthouse Kiln Burners 7-9	0.18	0.33	0.18	0.33
KS5- Malthouse Kiln Burner 10	0.06	0.11	0.06	0.11
CS- Pellet Mill Cooler Cyclone	0.36	0.98	0.36	0.98
BS1- Malthouse Boilers 1&2	0.05	0.08	0.05	0.08
BS2- Pellet Mill Boiler	0.02	0.08	0.02	0.08
S1- Steep Tank Conveyor 1 Filter	0.03	0.017	0.005	0.003
S2- Steep Tank Conveyor 2 Filter	0.03	0.017	0.005	0.003
S27- Kiln 2 Burner 1	0.13	0.40	0.13	0.40
S28- Kiln 2 Burner 2	0.13	0.40	0.13	0.40
S29- Kiln 2 Burner 3	0.13	0.40	0.13	0.40
S30- Kiln 2 Burner 4	0.13	0.40	0.13	0.40
S31- Kiln 2	1.79	6.90	1.13	4.37
S32- New Malt Leg Conveyor Filter	0.04	0.015	0.007	0.003
S33- Analysis Bin 1 Filter	0.04	0.01	0.007	0.001
S34- Analysis Bin 2 Filter	0.04	0.01	0.007	0.001
S35- Kiln Byproduct Cyclone Filter	0.01	0.01	0.007	0.01
S36- New Malt Conveyor 3 Filter	0.03	0.02	0.005	0.003
S37- Micro Bins Conveyor Filter	0.01	0.001	0.001	0.0002
S38-S40- GV Boilers 1, 2 & 3	0.04	0.13	0.04	0.13
S41-S43- GV Boilers 4, 5 & 6	0.04	0.13	0.04	0.13
S44- Makeup Air Heater 1	0.02	0.07	0.02	0.07
S45- Makeup Air Heater 2	0.02	0.07	0.02	0.07
S46- Malt Storage Bins Conveyor 1 Filter	0.03	0.014	0.005	0.002
S47- Malt Storage Bins Conveyor 2 Filter	0.03	0.014	0.005	0.002

* Pounds per hour on a rolling daily average
** Tons per any consecutive 12-month period

Table 5-24: Proposed Limits on Short-term NOx Emissions on New Equipment

Stack Description	NOx*	NOx*
	ppm @ 3% O2	lb/hr
KS1- Kiln 1 Burner 1	30	
KS2- Kiln 1 Burners 2-5	30	
KS3- Kiln 1 Burner 6	30	
KS4- Kiln 1 Burners 7-9	30	
KS5- Kiln 1 Burner 10	30	
S27- Kiln 2 Burner 1	30	
S28- Kiln 2 Burner 2	30	
S29- Kiln 2 Burner 3	30	
S30- Kiln 2 Burner 4	30	
S38- GV Boiler 1	20	
S39- GV Boiler 2	20	
S40- GV Boiler 3	20	
S41- GV Boiler 4	20	
S42- GV Boiler 5	20	
S43- GV Boiler 6	20	
S44- Makeup Air Heater 1		0.22
S45- Makeup Air Heater 2		0.22

* As measured by EPA Method 7E

5.3.2 Operating Limits

Table 5-25: Proposed Grain and Malt Throughput Limits

Activity	Metric Tons/hr*	Metric Tons/yr**
Barley unloaded from trucks	150	145,000
Barley unloaded from railcars	150	179,000
Pellet production	5	27,000
Green malt dried in Kiln 1	17	130,000
Green malt dried in Kiln 2	21	162,000

* MT/hour on rolling daily average
** MT per any consecutive 12-month period

Sulfur will not be burned in Kiln 2. Sulfur burning in Malthouse Kiln 1 will remain unchanged from current permit limits.

Only natural gas fuel will be used in the malthouse boilers, the kiln 1 burners, the kiln 2 burners, germination vessel boilers and makeup air heaters.

Natural gas usage will be restricted in the following equipment:

- Malthouse Boilers 1 & 2 (BS1): 6.25 MM Btu/hr total hourly heat input and 21.1 MM cf/year natural gas usage
- Kiln 1 Heaters (KS1-KS5): 290 MM cf/year natural gas usage
- Kiln 2 Heaters (KB1-KB4): 420 MM cf/year natural gas usage

For Germination Vessel Boilers 1, 2 and 3, only two boilers will operate at a time.
For Germination Vessel Boilers 4, 5 and 6, only two boilers will operate at a time.

Cleaning with sodium hypochlorite will be limited to a maximum of 2 cleaning events per day.

The emergency generator (EG) will operate a maximum of 100 hours per calendar year in non-emergency service (maintenance and testing).

5.3.3 Monitoring and Recordkeeping

Great Western Malting proposes the following monitoring and recordkeeping that will be in addition to the monitoring required by the current Permit to Construct (Conditions 2.12, 2.13, 2.14 and 2.15).

1. Track the quantity of green malt processed in Kiln 2 in MT/hr daily rolling average and total MT produced in any consecutive 12-month period.
2. Perform monthly inspections of the new dust filters in accordance with manufacturer specifications. Record the differential pressure reading on each filter to assure proper operation. Inspection records will maintained at the plant.
3. Keep records of maintenance performed on the new dust filters.
4. Keep records of the hourly heat input into Malthouse Boilers 1&2 (BS1).
5. Keep records of the total quantity of natural gas burned in the Malthouse Boilers (BS1) on a 12-month rolling total.
6. Keep records of the total quantity of natural gas burned in each kiln (Kiln1 & Kiln 2) as 12-month rolling totals.
7. Perform a source test for NOx emissions on one of the ten new burners for Kiln 1 (KS1, KS3 or KS5) using EPA Method 7E.
8. Perform a source test for NOx emissions on one of the four new Kiln 2 burners (S27, S28, S29 or S30) using EPA Method 7E.
9. Perform a source test for NOx emissions on one of the new germination vessel boilers (GVB1-GVB6) using EPA Method 7E.
10. Keep records of the dates cleaning events are performed in the germination beds (GB) and germination vessels (GV1-GV4).
11. Track the calendar year total hours of operation of the emergency generator.

6.0 Facility Classification

The Great Western Malting Facility in Pocatello is a synthetic minor source of emissions. The facility's emissions are limited by enforceable conditions in the Permit To Construct No. P-060312.

The Prevention of Significant Deterioration (PSD) applicability threshold for sources that are in one of the listed PSD source categories is 100 tons/year. The PSD applicability threshold for sources that are not in one of the listed categories is 250 tons/year of NSR pollutants (excluding CO2e).

The Great Western Malting facility is not in one of the listed categories so the PSD applicability threshold is 250 tons/year for the Pocatello plant.

Pre-project and post project annual emissions are shown in the following table:

Annual NSR Pollutant Emissions (Tons/year)

	PM10	**PM2.5**	**SO2**	**NOx**	**CO**	**VOC**
Pre-Project PTE	8.50	5.20	20.53	14.55	17.33	9.40
Post Project PTE	17.98	12.35	20.68	18.34	86.96	23.25

The current pre-project total PTE of NSR pollutants is less than 250 tons per year. The facility currently is a minor source and not a PSD source.

After the expansion project is completed the new air permit will contain enforceable conditions that will limit emissions from the facility to less than 100 tons/year. The post project total PTE of NSR pollutants will be less than 250 tons/year and the facility will remain a minor source and not subject to PSD.

In summary:

Is the plant a designated category under PSD: __ yes _X_ no

If yes, give the PSD category: ____NA____

Potential to Emit after expansion: 87 tons/year

Pollutant that defines Potential to Emit: ____ Carbon Monoxide____

The facility is located in an area that is designated attainment or unclassifiable for all pollutants such that the project is not subject to nonattainment NSR. The Great Western Malting project will not require emission offsets for permitting the expansion.

Because the plant is not subject to PSD or nonattainment NSR requirements, the expansion project is eligible to apply for Pre-Permit Construction approval.

7.0 Ambient Impact Assessments

This section of the report contains the air dispersion modeling analysis and results for potential offsite impacts of PM10, PM2.5, CO, NO_2, chlorine and formaldehyde. The analysis was performed by Air Sciences, Inc. The modeling report, modeling protocol and protocol approval are presented.

AIR SCIENCES INC.

DENVER • PORTLAND • LOS ANGELES

Revised Air Quality Modeling Report: Great Western Malting Facility in Pocatello, Idaho

PREPARED FOR:
GREAT WESTERN MALTING CO.

PROJECT NO. 174-29-1
DECEMBER 2, 2015

Table of Contents

List of Tables

List of Figures

Appendices

Appendix A – Process Flow Diagrams
Appendix B – DEQ's Conditional Protocol Approval Letter
Appendix C – Original Modeling Protocol
Appendix D – Modeling Protocol Addendum #1
Appendix E –Summary of Modeling Emission Inventory
Appendix F – GWM Stack Temperature and Flow Rate Documentation
Appendix G – DEQ PTC Modeling Forms (MI1 - MI4)
Appendix H – NO_X/NO_2 In-Stack Ratio Documentation

1.0 Summary

Great Western Malting Co. (GWM) produces high-quality malted barley that is a basic ingredient in beer. GWM is planning to increase the malting capacity of its malting facility located in Pocatello, Idaho. The existing malt house is located at 42° 53’ 35.6” N and 112° 29’ 17.2” W. More specific information regarding the facility location, including a map showing the location of the GWM facility and surrounding vicinity, is provided in Section 2.2.

In general, the main proposed change at the malting facility is to increase annual malt production. The expansion project will add new malting equipment to the facility, including new germination vessels, new steeps, and a new kiln. The existing malting equipment will remain unchanged. The increase in malt production will require additional storage and cleaning equipment at the existing facility. No changes to the barley handling equipment at the existing facility are planned, as this handling equipment is sized to handle the additional barley needed for the new malting equipment. However, the barley throughput will increase and there will be a few new barley transfer points added to the facility as barley is conveyed to the new malting equipment.

The air quality analysis described in this revised modeling report for Idaho Department of Environmental Quality (DEQ) review, demonstrates that emissions from the proposed project will not result in criteria pollutant impacts that exceed state or federal ambient air quality standards, and that toxic pollutant impacts will not exceed Idaho’s toxic air pollutant (TAP) increments.

2.0 Project Description and Background as it Relates to Modeling Analyses

From an air quality perspective, the existing facility is a synthetic minor source of air pollution and currently operates under a Permit to Construct. The GWM facility is located in an attainment area for all criteria air pollutants, that is, existing air pollutant levels are less than the National Ambient Air Quality Standards (NAAQS). Emissions from the facility will remain less than 100 tons/year after the expansion so it will remain a synthetic minor source and not subject to Prevention of Significant Deterioration (PSD) permitting.

Based on GWM's review of emissions from new project sources (discussed in more detail in Section 3.2), GWM asserts that only Carbon Monoxide (CO), Nitrogen Oxides (NO_X), particulate matter less than 10 microns in aerometric diameter (PM_{10}), and particulate matter less than 2.5 microns in aerometric diameter ($PM_{2.5}$) need to be modeled. The SO_2 emissions increase from the project does not exceed modeling thresholds and modeling is not required.

2.1 General Facility/Project Description

Complete process flow diagrams for the existing and proposed expansion operations at the GWM facility are provided in Appendix A.

2.1.1 Existing Facility Process

Grain (mainly barley) is received by truck or railcar and unloading operations occur at the Truck Bay (TB) and Rail Bays (RB1 and RB2). During unloading, the trucks or railcars discharge grain into hoppers, from which the grain is conveyed through the headhouse. Unloading operations result in the generation of particulate matter (PM) emissions. The truck bay receiving pit is equipped with side draw vacuums with exhaust to baghouse #1 (BH1). Hopper-type trucks account for a majority of the truck receiving operations. These trucks and the railcar unloading operations employ choke feeds to the receiving pit to minimize fugitive PM emissions.

The grain is transferred through the headhouse to the grain storage silos. PM emissions generated by headhouse transfer operations are controlled by BH1. Material collected by all the centralized baghouse systems (BH1, BH2, and BH3) is sent to a pellet mill. The grain is then cleaned and graded with transfers and the cleaning device controlled by BH2. "Thin" barley is transferred to Feed Barley transfer bins, and this material is trucked offsite and used as animal feed. Feed Barley transfer operations are also controlled by BH1. Feed Barley truck loadout operations are controlled by a cyclone side vacuum draw system that exhausts to BH3.

After cleaning, the grain is transferred to the malthouse, where it is steeped by placing it in large tanks with cool, oxygen-enriched water. Following steeping, the grain is dropped to one of six temperature- and humidity-controlled germination beds and allowed to grow. The steeping and germination processes also are served by chilled water systems. The steeping and germination process requires heated air provided by two natural-gas-fired hot water boilers that exhaust combustion byproducts to a common stack (BS1).

Following germination, “green” malt is dried in an indirect natural gas-fired malt kiln (KSE stack). The existing malt kiln has two levels. Green malt enters the upper deck and is dried. The green malt is then transferred to the lower deck of the kiln where it is further dried to about 4% moisture content. During a portion of the kilning, sulfur may be burned in a sulfur stove and exhausted into the kiln, primarily as sulfur dioxide (SO_2). Sulfur is only burned if customer product specifications require its use.

Currently, heat for the kiln is provided by ten natural gas-fired malt kiln burners that exhaust through 5 malt kiln burner stacks (KS1-KS5). The burners for the existing kiln will be replaced with ten air-to-air heat exchangers to provide drying air to the kiln. The new heat exchangers will have ten natural gas-fired burners, one for each heat exchanger. Each burner will have a 7.9 MM Btu/hr heat input capacity. The exhausts from the new burners will discharge through the 5 malt kiln burner stacks (KS1-KS5).

The malted barley is then cleaned and transferred to the malt storage silos until it is shipped. PM generated during the cleaning is collected in the BH2 baghouse, and transfers are collected in the BH3 baghouse.

Cleaning byproducts and material collected by the baghouses are sent to a pellet mill, where the material is pelletized and shipped offsite. Loadout of pelletized material occurs via truck and results in fugitive PM emissions. The pellet mill mixer requires steam provided by a steam boiler that discharges combustion byproducts through BS2.

The malt is shipped by railcar or truck. PM is generated during loading. These emissions occur at the RB1, RB2, and TB emission points.

Fugitive road dust is generated by truck deliveries to, and shipments from, the plant. The trucks travel on the paved access roads.

2.1.2 New Facility Process

The expansion project will add new malting equipment to the facility, thus increasing production throughput to a total of about 324,000 metric tons (MT) of grain per year. No changes to the grain handling equipment at the existing plant are planned as the equipment is already sized to handle the additional grain needed.

The new malting equipment will include 16 new steeps, four new germination vessels, and one new kiln. The kiln will use four air-to-air heat exchangers to provide the drying air. The burners for the heat exchangers will be natural-gas-fired, each at 18.15 MM Btu/hr heat input capacity. Each burner will have its own exhaust stack. Air from the kiln will be discharged from a single stack. Sulfur will not be burned in the new kiln.

Each steep will have its own exhaust stack and each germination vessel will have two exhaust stacks. Just like in the existing germination equipment, the new germination vessels will be sanitized using sodium hypochlorite, which will produce minor amounts of chlorine emissions.

The hot water for germination will be provided by six new natural-gas-fired boilers, four for operation and two as backup. Each boiler will have a 2.0 MM Btu/hr heat input capacity. Heated makeup air for the steep building will be provided by two new natural gas-fired makeup air heaters, each with 2.188 MM Btu/hr heat input capacity.

After the malt is dried in the kiln, it will be cleaned and placed into storage. The stored malt will be cleaned again before it is loaded into trucks or railcars and shipped offsite. The increase in malt production will require the addition of storage and cleaning equipment to the existing plant. There will be two new grain transfer points as grain is conveyed to the new malting equipment. New dust collector(s) will be added to capture PM from the grain and malt transfers. The plan for the facility is to:

- Add ten new malt storage silos with filters on the fill conveyors.
- Replace some existing kiln malt cleaning equipment with new equipment (scalper and aspirator). The existing baghouses have enough capacity and will be used to control dust.
- Add two new malt analysis bins with filters.
- Add four new truck loadout bins and chutes with a filter on the fill conveyor.
- Add a cyclone for conveying byproducts to the byproduct bin. A dust collector will be used to control emissions from the cyclone exhaust.
- Add new conveyors and transfers as needed to move the malt and other materials. Dust from these activities will be controlled using the existing baghouses or by the addition of new dust collectors.

The existing pellet mill has enough capacity to handle the barley residue, malt byproducts, and baghouse material from the expansion so no changes are planned to the pellet mill system or pellet boiler.

For more information on equipment to be used in the project, see Sections 1 and 2 of the "Pre-Permit Construction Approval and Application to Modify the PTC" for the Great Western Malting project.

2.2 Location of Project

__X__A map showing the geographical location of the facility is provided in this section or a reference is provided to another location in the application where a map is provided.

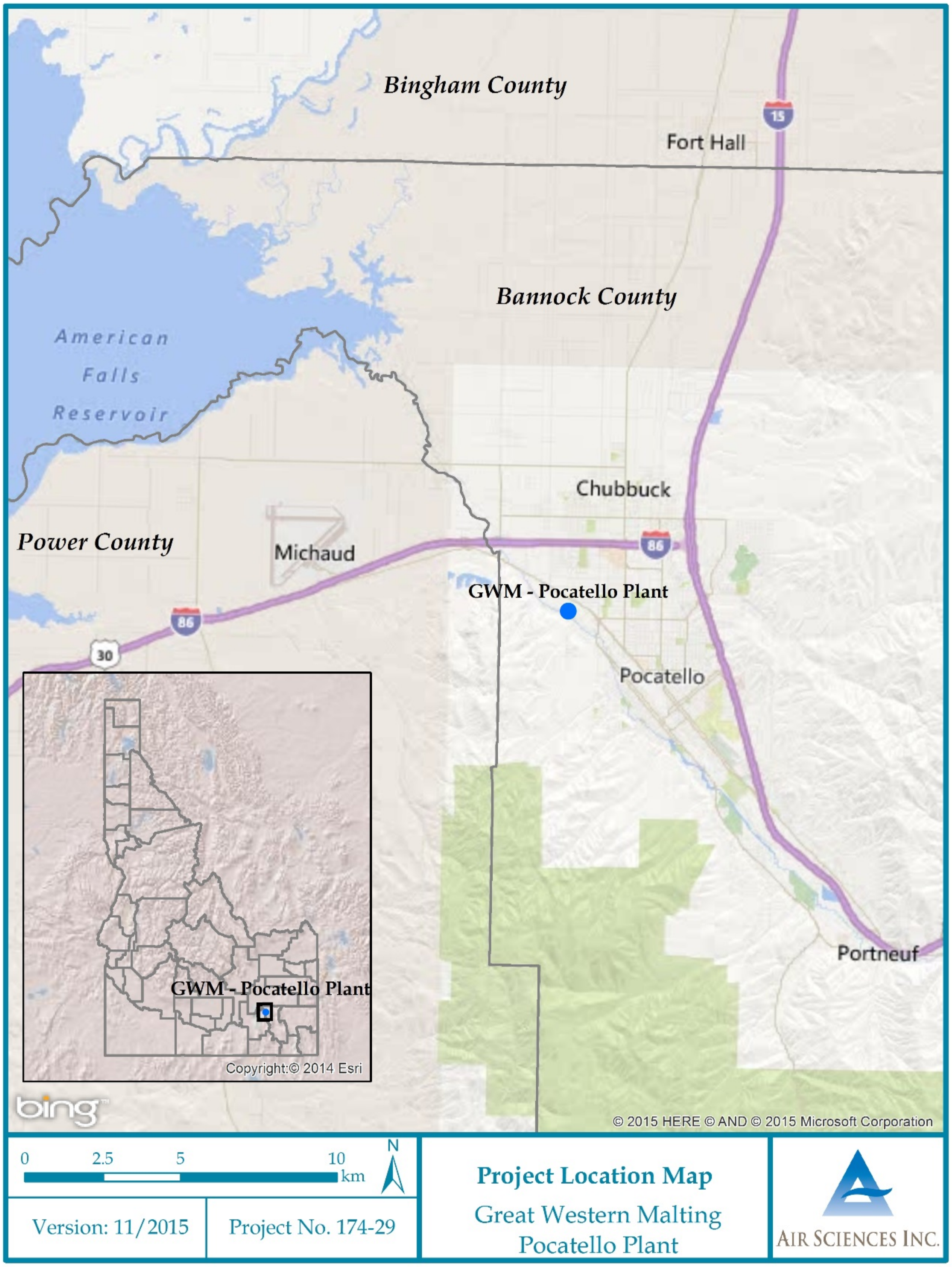
Figure 1 shows the location of GWM facility and surrounding vicinity. The existing malt house is located at 42° 53' 35.6" N and 112° 29' 17.2" W. The Universal Transverse Mercator (UTM) coordinate system projected in North American Datum of 1983 (NAD83), Zone 12, was used in the air quality modeling analysis to define all locations in the modeling domain (sources, buildings, and receptors). Within the UTM NAD83 Zone 12 coordinate system, the GWM facility is located at 378,496 meters easting and 4,750,031 meters northing.

The GWM facility is located in an industrial area just west of Route 30, in Pocatello, Idaho. Southwest of the facility and Pocatello is a relatively rural area of more complex terrain below Howard Mountain on the northern edge of the Wasatch Range. Approximately two miles northwest of the facility is the Don Siding Plant of the J.R. Simplot Company (Simplot), and beyond that lie the agricultural lands surrounding the American Falls Reservoir. Per DEQ request, Simplot is of interest as a relatively large source of pollution, and is included in the cumulative NAAQS analysis. East of the GWM facility (and surrounding industrial area) is the town of Pocatello. Beyond Pocatello is the complex region below Camelback Mountain.

Consistent with previous Industrial Source Complex (ISC) modeling of the GWM facility in 2005 and based on a review of the current land use surrounding the GWM facility today, the land use in the vicinity of the facility is considered rural under the Auer land use scheme. It should be noted that the "rural" keyword that was applicable for the ISC model is no longer allowed/required for the AERMOD model.

The GWM facility is located in an attainment area for all criteria air pollutants, that is, existing air pollutant levels are less than the NAAQS.

Figure 1. Project Location Map



2.3 Existing Permits and Modeling Analyses Performed

_N/A_ Any existing air quality permits are listed and described in this section, and any associated air quality modeling analyses have been described and referenced, and submitted if appropriate.

GWM Comment: The GWM facility currently operates under a Permit to Construct. Previous modeling using the ISC model was performed for the facility in 2005 for the permit renewal. All sources modeled in 2005 where included in this modeling so the old 2005 files are not attached with this modeling report.

3.0 Modeling Analyses Applicability and Protocol

In this section, the estimated emissions and emissions changes from the GWM facility related to proposed modification are summarized and compared to their appropriate modeling trigger thresholds. In addition, discussion is provided regarding the applicable ambient standards considered in the modeling analyses.

3.1 Applicable Standards

Ambient air quality standards are maximum concentrations of pollutants in ambient air that are considered protective of the public health. These standards are established by EPA for air pollutants with known or anticipated human health effects. The estimated total ambient concentrations (modeled concentrations plus applicable background concentrations) from the modeling analysis are compared with the NAAQS for compliance demonstration.

Criteria pollutant NAAQS are listed along with significant impact levels (SILs) in Table 1. Note that Table 1 provided below is DEQ's full NAAQS table for all criteria pollutants. However, based on GWM's review of emissions from new GWM project sources, only CO, NO_2, PM_{10}, and $PM_{2.5}$ require explicit dispersion modeling for the expansion project.

EPA has also promulgated a NAAQS for lead (Pb); however, Pb emissions at the GWM facility are expected to be minimal; therefore, Pb is not addressed further in the modeling analysis. In addition, the GWM project emissions of SO_2 do not trigger modeling, and these pollutants are not addressed further in the modeling analysis.

Table 1. Applicable Regulatory Limits

Pollutant	Averaging Period	Significant Impact Levels[a] ($\mu g/m^3$)[b]	Regulatory Limit[c] ($\mu g/m^3$)	Modeled Design Value Used[d]
PM_{10}[e]	24-hour	5.0	150[f]	Maximum 6th highest[g]
$PM_{2.5}$[h]	24-hour	1.2	35[i]	Mean of maximum 8th highest[j]
	Annual	0.3	12[k]	Mean of maximum 1st highest[l]
Carbon monoxide (CO)	1-hour	2,000	40,000[m]	Maximum 2nd highest[n]
	8-hour	500	10,000[m]	Maximum 2nd highest[n]
Sulfur Dioxide (SO_2)	1-hour	3 ppb[o] (7.8 $\mu g/m^3$)	75 ppb[p] (196 $\mu g/m^3$)	Mean of maximum 4th highest[q]
	3-hour	25	1,300[m]	Maximum 2nd highest[n]
	24-hour	5	365[m]	Maximum 2nd highest[n]
	Annual	1.0	80[r]	Maximum 1st highest[n]
Nitrogen Dioxide (NO_2)	1-hour	4 ppb (7.5 $\mu g/m^3$)	100 ppb[s] (188 $\mu g/m^3$)	Mean of maximum 8th highest[t]
	Annual	1.0	100[r]	Maximum 1st highest[n]
Lead (Pb)	3-month[u]	NA	0.15[r]	Maximum 1st highest[n]
	Quarterly	NA	1.5[r]	Maximum 1st highest[n]
Ozone (O_3)	8-hour	40 TPY VOC[v]	75 ppb[w]	Not typically modeled

a. Idaho Air Rules Section 006 (definition for significant contribution) or as incorporated by reference as per Idaho Air Rules Section 107.03.b.
b. Micrograms/cubic meter.
c. Incorporated into Idaho Air Rules by reference, as per Idaho Air Rules Section 107.
d. The maximum 1st highest modeled value is always used for the significant impact analysis unless indicated otherwise. Modeled design values are calculated for each ambient air receptor.
e. Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers.
f. Not to be exceeded more than once per year on average over 3 years.
g. Concentration at any modeled receptor when using five years of meteorological data.
h. Particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers.
i. 3-year mean of the upper 98th percentile of the annual distribution of 24-hour concentrations.
j. 5-year mean of the 8th highest modeled 24-hour concentrations at the modeled receptor for each year of meteorological data modeled. For the SIL analysis, the 5-year mean of the 1st highest modeled 24-hour impacts at the modeled receptor for each year.
k. 3-year mean of annual concentration.
l. 5-year mean of annual averages at the modeled receptor.
m. Not to be exceeded more than once per year.
n. Concentration at any modeled receptor.
o. Interim SIL established by EPA policy memorandum.
p. 3-year mean of the upper 99th percentile of the annual distribution of maximum daily 1-hour concentrations.
q. 5-year mean of the 4th highest daily 1-hour maximum modeled concentrations for each year of meteorological data modeled. For the significant impact analysis, the 5-year mean of 1st highest modeled 1-hour impacts for each year is used.
r. Not to be exceeded in any calendar year.
s. 3-year mean of the upper 98th percentile of the annual distribution of maximum daily 1-hour concentrations.
t. 5-year mean of the 8th highest daily 1-hour maximum modeled concentrations for each year of meteorological data modeled. For the significant impact analysis, the 5-year mean of maximum modeled 1-hour impacts for each year is used.
u. 3-month rolling average.
v. An annual emissions rate of 40 ton/year of VOCs is considered significant for O_3.
w. Annual 4th highest daily maximum 8-hour concentration averaged over three years.

__X__ All TAPs identified in the emissions inventory for the project are listed in the TAPs Emission Level (EL) and Acceptable Ambient Concentrations / Acceptable Ambient Concentrations for Carcinogens AAC/AACC Table in this section.

TAP screening emission levels and applicable standards are shown in Table 2.

Table 2. TAP Emissions Levels and Standards

Non-Carcinogenic TAP	CAS Number	Screening Emissions Level (EL) (lb/hr)	Acceptable Ambient Concentrations (AAC) (mg/m^3)
Acrolein	107-02-8	0.017	0.0125
Chlorine	7782-50-5	0.2	0.15
Ethyl Benzene	100-41-4	29	21.75
Hexane	110-54-3	12	9
Naphthalene	91-20-3	3.33	2.5
Toluene	108-88-3	25	18.75
Xylenes	1330-20-7	29	21.75
Carcinogenic TAP	**CAS Number**	**Screening Emissions Level (EL) (lb/hr)**	**Acceptable Ambient Concentrations for Carcinogens (AACC) ($\mu g/m^3$)**
Acetaldehyde	75-07-0	3.0E-03	4.5E-01
Benzene	71-43-2	8.0E-04	1.2E-01
Formaldehyde	50-0-0	5.1E-04	7.7E-02
PAH's (including naphthalene)	NA	9.1E-05	1.4E-02

3.2 Criteria Pollutant Modeling Applicability

__X__Explanations/documentation why modeling was or was not performed for each criteria pollutant are provided in this section.

__X__Emissions calculations that clearly show how the modeling applicability determination was performed are provided in this section.

Following Idaho Department of Environmental Quality's modeling guidelines (IDEQ 2013), modeling needs to be conducted when the facility's or project's pollutant emissions exceed modeling thresholds. The facility criteria pollutant emission increases associated with the proposed modification and associated modeling thresholds are shown in Table 3.

Table 3. GWM Criteria Pollutant Emissions and Modeling Thresholds

Pollutant	Type	Estimated Emissions from New Project Sources	Units	DEQ Level 1 Modeling Threshold[a]	Units	Modeling Required?
CO	Short-Term	34.7	lb/hr	15	lb/hr	Yes
NO_X	Short-Term	6.2	lb/hr	0.2	lb/hr	Yes
	Long-Term	16.1	ton/yr	1.2	ton/yr	Yes
SO_2	Short-Term	0.10	lb/hr	0.21	lb/hr	No
	Long-Term	0.25	ton/yr	1.2	ton/yr	No
PM_{10}	Short-Term	3.3	lb/hr	0.22	lb/hr	Yes
$PM_{2.5}$	Short-Term	2.4	lb/hr	0.054	lb/hr	Yes
	Long-Term	7.5	ton/yr	0.35	ton/yr	Yes

[a.] DEQ's Level 1 thresholds in Table 2 of the modeling guidelines.

Table 4 lists criteria pollutants for which site-specific modeling analyses were performed to demonstrate compliance with NAAQS.

Table 4. Modeling Applicability

Criteria Pollutant	Modeled (yes/no)	Basis for Exclusion from Modeling
$PM_{2.5}$ 24-hour	Yes	___BRC Exempt[a]
		___Emissions Below Level l Thresholds[b]
		___Emissions Below Level II Thresholds[c]
$PM_{2.5}$ annual	Yes	___BRC Exempt
		___Emissions Below Level l Thresholds
		___Emissions Below Level II Thresholds
PM_{10} 24-hour	Yes	___BRC Exempt
		___Emissions Below Level l Thresholds
		___Emissions Below Level II Thresholds
NO_2 1-hour	Yes	___BRC Exempt
		___Emissions Below Level l Thresholds
		___Emissions Below Level II Thresholds
NO_2 annual	Yes	___BRC Exempt
		__Emissions Below Level l Thresholds
		___Emissions Below Level II Thresholds
SO_2 1-hour, 3-hour	No	___BRC Exempt
		_X_Emissions Below Level l Thresholds
		___Emissions Below Level II Thresholds
SO_2 annual	No	___BRC Exempt
		_X_Emissions Below Level l Thresholds
		___Emissions Below Level II Thresholds
CO 1-hour, 8-hour	Yes	___BRC Exempt
		___Emissions Below Level l Thresholds
		___Emissions Below Level II Thresholds

a. If the project would have qualified for a Category I BRC permitting exemption for the criteria pollutant in question, as per Idaho Air Rules Section 221.01, except for the emissions quantities of another criteria pollutant, then a NAAQS compliance analysis is not required under Section 203.02 or 403.02 for that criteria pollutant.

b. Level I Modeling Thresholds from Table 2 in Section 3 of the DEQ Modeling Guideline. NAAQS compliance is assured through DEQ's non-site-specific modeling analyses.

c. Level II Modeling Thresholds from Table 2 in Section 3 of the DEQ Modeling Guideline. NAAQS compliance is assured through DEQ's non-site-specific modeling analyses. Level II Modeling Thresholds can only be used with prior DEQ approval.

3.3 TAP Modeling Applicability

__X__ Explanation/documentation on why modeling was or was not performed for emissions of each TAP identified in the emissions inventory of the application are provided in this section.

Idaho Air Rules Section 161 states, "Any contaminant which is by its nature toxic to human or animal life or vegetation shall not be emitted in such quantities or concentrations as to alone, or in combination with other contaminants, injure or unreasonably affect human or animal life or vegetation." DEQ may require toxics analyses as a case-by-case basis.

The evaluation of the GWM non-carcinogen TAP emissions is shown in Table 5. Based on that screening, GWM determined that chlorine would need to be modeled for compliance and was compared to an AAC of 0.15 $\mu g/m^3$ on a 24-hour average basis. For GWM's dispersion modeling analysis, the highest-first-highest (H1H) 24-hour average modeled concentrations were compared to the AAC for chlorine.

The evaluation of the GWM carcinogen TAP emissions is shown in Table 6. Based on that screening, GWM determined that formaldehyde would need to be modeled for compliance and was compared to an AACC of 7.7E-02 $\mu g/m^3$. For GWM's dispersion modeling analysis, the highest annual concentration was compared to the AACC.

Table 5. Pre- and Post-Project Potential to Emit (PTE) for Non-Carcinogenic TAP

Non-Carcinogenic TAP	Pre-Project 24-hour Average Emission Rates	Post Project 24-hour Average Emission Rates	Change in 24-hour Average Emission Rates	Screening EL	Exceeds EL?
	lb/hr	lb/hr	lb/hr	lb/hr	Yes/No
Acrolein	0.00033	0.00046	0.00013	0.017	No
Ethyl Benzene	0.00115	0.00161	0.00046	29	No
Hexane	0.00077	0.00107	0.00030	12	No
Naphthalene	0.00004	0.00005	0.00001	3.33	No
Toluene	0.00445	0.00620	0.00175	25	No
Xylenes	0.00330	0.00461	0.00131	29	No
Chlorine	**0.5375**	**1.0750**	**0.538**	**0.2**	**Yes**

* Chlorine emissions increases from new sources are 6.45 lb/hr for 2 hours/day for a total of 12.9 lb/day. This equates to 0.538 lb/hr as a 24-hr average.

Table 6. Pre- and Post-Project PTE for Carcinogenic TAP

Carcinogenic TAP	Pre-Project Annual Average Emission Rates	Post Project Annual Average Emission Rates	Change in Annual Average Emission Rates	Carcinogenic Screening EL	Exceeds EL?
	lb/hr	lb/hr	lb/hr	lb/hr	Yes/No
Acetaldehyde	1.71E-04	4.23E-04	2.52E-04	3.0E-03	No
Benzene	3.16E-04	7.87E-04	4.71E-04	8.0E-04	No
Formaldehyde	**6.72E-04**	**1.67E-03**	**1.00E-03**	**5.1E-04**	**Yes**
PAH's (including naphthalene)	1.58E-05	3.93E-05	2.35E-05	9.1E-05	No

3.4 Modeling Protocol

__X__If a protocol was submitted to DEQ prior to performing the modeling analyses, the protocol and DEQ's conditional protocol approval notice is included in Appendix B of this Modeling Report.

A modeling protocol was submitted to DEQ on October 2, 2015 and is included as Appendix C. An addendum to the protocol was submitted on October 28, 2015 and is included as Appendix D. The DEQ protocol approval letter dated November 5, 2015 was received on November 6, 2015 and is included in Appendix B.

__X__Concerns identified by DEQ in the protocol approval notice have been addressed in the analyses performed and in this Modeling Report.

4.0 Modeled Emissions Sources

__X__The modeling emissions inventory and the emissions inventory presented in other parts of the permit application are consistent, and if they are not identical numbers, it is clearly shown, with calculations submitted, how the modeled value was derived from the value provided in the emissions inventory.

A summary modeling emissions inventory for GWM sources is provided in Appendix E.

Table 7 shows the existing and proposed emission points and their modeling identifications used for the modeling analysis. Table 8 shows the emissions for each source.

Table 9 shows a comparison of facility-wide PTE emissions pre- and post-project.

Table 7. GWM Emission Sources and Modeling Identification

Model ID	Description	New or Existing
STC1F	Spot Filter - Barley to Steeps	New
STC2F	Spot Filter - Above Steeps	New
GV1-4	Germination Vessels	New
KB1	Kiln Air Heater 1 Burner Stack	New
KB2	Kiln Air Heater 2 Burner Stack	New
KB3	Kiln Air Heater 3 Burner Stack	New
KB4	Kiln Air Heater 4 Burner Stack	New
K2	Kiln 2 Exhaust	New
NMLF	Spot Filter - Analysis Bins Elevator	New
BA1F	Spot Filter - Analysis Bin W	New
BA2F	Spot Filter - Analysis Bin E	New
KBPCF	Spot Filter - Byproduct Cyclone	New
NMC3F	Spot Filter - Kiln Tunnel	New
MBCF	Spot Filter - Micro Bin	New
GVB1	Germination Vessel Boiler 1	New
GVB2	Germination Vessel Boiler 2	New
GVB4	Germination Vessel Boiler 4	New
GVB5	Germination Vessel Boiler 5	New
MAU1	Make Up Air Unit 1	New
MAU2	Make Up Air Unit 2	New
NMSBC1F	New Malt Storage Bins 1-5 Conveyor 1 Filter	New
NMSBC2F	New Malt Storage Bins 6-10 Conveyor 2 Filter	New
KS1-5	Kiln 1 Burner Stacks	New
EG1	Emergency Generator	Existing
BH1	Baghouse - Barley Head House	Existing
BH2	Baghouse - Malt & Barely Cleaning	Existing
BH3	Baghouse - Malt Cleaning, Loading & Transfer	Existing
BS1	Malt House Boilers Stack	Existing
BS2	Pellet Mill Boiler Stack	Existing
CS	Pellet Mill Cooler Stack	Existing
RB1	Rail Bay	Existing
RB2	Rail Bay	Existing
TB	Truck Bay	Existing
KSE01-5	Kiln 1	Existing

Table 8. GWM Emission Rates for Existing and Proposed Sources

Model ID	CO (lb/hr)	NO_X (lb/hr)	NO_X (lb/yr)	$PM_{2.5}$ (lb/day)	$PM_{2.5}$ (lb/yr)	PM_{10} (lb/day)	CL_2 (lb/day)[a]	CH_2O (lb/hr)[a]	New or Existing
STC1F	--	--	--	0.1	5.7	0.7	--	--	New
STC2F	--	--	--	0.1	5.7	0.7	--	--	New
GV1-4[b]	--	--	--	--	--	--	12.9	--	New
KB1	4.0	0.7	3,885	3.2	798.0	3.2	--	0.0003	New
KB2	4.0	0.7	3,885	3.2	798.0	3.2	--	0.0003	New
KB3	4.0	0.7	3,885	3.2	798.0	3.2	--	0.0003	New
KB4	4.0	0.7	3,885	3.2	798.0	3.2	--	0.0003	New
K2	--	--	--	27.2	8,734	43.0	--	--	New
NMLF	--	--	--	0.2	5.2	1.0	--	--	New
BA1F	--	--	--	0.2	2.6	1.0	--	--	New
BA2F	--	--	--	0.2	2.6	1.0	--	--	New
KBPCF	--	--	--	0.2	20.1	0.2	--	--	New
NMC3F	--	--	--	0.1	5.2	0.7	--	--	New
MBCF	--	--	--	0.0	0.5	0.2	--	--	New
GVB1	0.2	0.1	526	0.4	133.2	0.4	--	0.00003	New
GVB2	0.2	0.1	526	0.4	133.2	0.4	--	0.00003	New
GVB4	0.2	0.1	526	0.4	133.2	0.4	--	0.00003	New
GVB5	0.2	0.1	526	0.4	133.2	0.4	--	0.00003	New
MAU1	0.2	0.2	1,917	0.4	145.7	0.4	--	0.00004	New
MAU2	0.2	0.2	1,917	0.4	145.7	0.4	--	0.00004	New
NMSBC1F	--	--	--	0.1	4.7	0.7	--	--	New
NMSBC2F	--	--	--	0.1	4.7	0.7	--	--	New
KS1	1.8	0.3	1,073	1.4	220.4	1.4	--	0.0001	New
KS2	7.0	1.2	4,292	5.7	881.6	5.7	--	0.0005	New
KS3	1.8	0.3	1,073	1.4	220.4	1.4	--	0.0001	New
KS4	5.3	0.9	3,219	4.2	661.2	4.2	--	0.0004	New
KS5	1.8	0.3	1,073	1.4	220.4	1.4	--	0.0001	New
EG1	0.4	---[c]	186	3.2	13.2	3.2	--	--	Existing
BH1	--	--	--	0.3	22.6	1.8	--	--	Existing
BH2	--	--	--	0.3	27.5	3.6	--	--	Existing
BH3	--	--	--	0.3	8.3	2.4	--	--	Existing
BS1	0.5	0.6	2,104	1.1	159.9	1.1	--	---[a]	Existing
BS2	0.2	0.3	2,190	0.5	166.4	0.5	--	---[a]	Existing
CS	--	--	--	8.7	1,960	8.7	--	--	Existing
RB1	--	--	--	1.1	66.3	6.1	--	--	Existing
RB2	--	--	--	1.1	66.3	6.1	--	--	Existing
TB	--	--	--	5.7	183.8	33.3	--	--	Existing
KSE01	--	--	--	4.3	1,402	6.8	--	--	Existing
KSE02	--	--	--	4.3	1,402	6.8	--	--	Existing
KSE03	--	--	--	4.3	1,402	6.8	--	--	Existing
KSE04	--	--	--	4.3	1,402	6.8	--	--	Existing
KSE05	--	--	--	4.3	1,402	6.8	--	--	Existing

a. The TAP emissions listed are from new emission units in accordance with the Idaho Air Rules Section 203.03. Sources that show a dash (---[a]) for these pollutants denote emissions not associated with the facility expansion.

b. These sources were modeled operating two hours per day and their emissions were divided among two release points at any given time.

c. Emissions from the emergency generator were not included in the 1-hour NO2 analyses.

Table 9. GWM Emission Rates for Pre- and Post-Project

Hourly Emissions	PM_{10} (lb/hr)	$PM_{2.5}$ (lb/hr)	SO_2 (lb/hr)	NO_X (lb/hr)	CO (lb/hr)
Pre-Project PTE Minus Fugitive Emissions	4.90	2.52	14.99	12.15	10.21
Post Project PTE Minus Fugitive Emissions	7.50	4.24	15.03	8.90	35.83
Changes in PTE	2.60	1.72	0.04	-3.25	25.62
Annual Emissions	**PM_{10} (ton/yr)**	**$PM_{2.5}$ (ton/yr)**	**SO_2 (ton/yr)**	**NO_X (ton/yr)**	**CO (ton/yr)**
Pre-Project PTE Minus Fugitive Emissions	8.50	5.20	20.53	14.55	17.33
Post Project PTE Minus Fugitive Emissions	17.98	12.35	20.68	18.34	86.96
Changes in PTE	9.48	7.15	0.15	3.79	69.63

4.1 Criteria Pollutants

AERMOD was run for the facility, and for competing sources (as needed), and the modeled impact added to the background concentration for comparison to the NAAQS. For the new sources as part of the expansion project, chlorine and formaldehyde impacts (without addition of background concentrations, which are assumed negligible) were compared to the AAC and AACC, respectively.

For comparison to significant impact levels, AERMOD was run for the expansion project sources (new sources) for each pollutant and averaging time. If the maximum impact was less than the applicable SIL, then the analysis was assumed completed for that pollutant and averaging time. If the pollutant impact exceeded the SIL, a full impact analysis was conducted, which includes impacts from both new and existing sources at the GWM facility and nearby sources (i.e., the Simplot facility). Emissions information related to the SIL and cumulative NAAQS analyses is provided below.

4.1.1 Modeled Emissions Rates for Significant Impact Level Analyses

__X__Emissions rates in Table 8 are identical to those in the model input files for SIL analyses.

__X__Calculation of modeled emissions are thoroughly documented in this section, and any unique handling of emissions in the model has been described.

The new facility sources as listed above in Table 8, constitute the emission sources considered for the significant impact area (SIA) modeling analyses. These emissions are also provided in DEQ's requested format below. Table 10 lists criteria pollutant emissions rates used in the SIL analyses. The values in Table 10 are the representative pounds per hour emission rate for each new source. The annual emission values, for example, were calculated by dividing the total pound per year emission rate by 8,760 hours. The daily emission rates were calculated by dividing the pound per day values by 24 hours. The hourly emission rates (conservatively assumed to equal the 8-hour average emission rates for CO) were used directly. These pounds per hour values for each averaging period were then converted to grams per second values for direct input to the modeling. A summary of the modeling emission inventory for the facility is provided in Appendix E.

Table 10. Modeled Emission Rates for SIL Analyses

Source ID	Source Description	Pollutant	Averaging Period	Emissions (lb/hr)[a]
STC1F	Spot Filter - Barley to Steeps	$PM_{2.5}$	24-hour	0.005
			Annual	0.001
		PM_{10}	24-hour	0.030
		NOx	1-hour	--
			Annual	--
		CO	1-hour	--
			8-hour	--
STC2F	Spot Filter - Above Steeps	$PM_{2.5}$	24-hour	0.005
			Annual	0.001
		PM_{10}	24-hour	0.030
		NOx	1-hour	--
			Annual	--
		CO	1-hour	--
			8-hour	--
KB1	Kiln Air Heater 1 Burner Stack	$PM_{2.5}$	24-hour	0.135
			Annual	0.091
		PM_{10}	24-hour	0.135
		NOx	1-hour	0.655
			Annual	0.443
		CO	1-hour	4.018
			8-hour	4.018
KB2	Kiln Air Heater 2 Burner Stack	$PM_{2.5}$	24-hour	0.135
			Annual	0.091
		PM_{10}	24-hour	0.135
		NOx	1-hour	0.655
			Annual	0.443
		CO	1-hour	4.018
			8-hour	4.018
KB3	Kiln Air Heater 3 Burner Stack	$PM_{2.5}$	24-hour	0.135
			Annual	0.091
		PM_{10}	24-hour	0.135
		NOx	1-hour	0.655
			Annual	0.443
		CO	1-hour	4.018
			8-hour	4.018
KB4	Kiln Air Heater 4 Burner Stack	$PM_{2.5}$	24-hour	0.135
			Annual	0.091
		PM_{10}	24-hour	0.135
		NOx	1-hour	0.655
			Annual	0.443
		CO	1-hour	4.018
			8-hour	4.018
K2	Kiln 2 Exhaust	$PM_{2.5}$	24-hour	1.132
			Annual	0.997
		PM_{10}	24-hour	1.790
		NOx	1-hour	--
			Annual	--
		CO	1-hour	--
			8-hour	--

NMLF	Spot Filter - Analysis Bins Elevator	$PM_{2.5}$	24-hour	0.007
			Annual	0.001
		PM_{10}	24-hour	0.041
		NOx	1-hour	--
			Annual	--
		CO	1-hour	--
			8-hour	--
BA1F	Spot Filter - Analysis Bin W	$PM_{2.5}$	24-hour	0.007
			Annual	0.0003
		PM_{10}	24-hour	0.041
		NOx	1-hour	--
			Annual	--
		CO	1-hour	--
			8-hour	--
BA2F	Spot Filter - Analysis Bin E	$PM_{2.5}$	24-hour	0.007
			Annual	0.0003
		PM_{10}	24-hour	0.041
		NOx	1-hour	--
			Annual	--
		CO	1-hour	--
			8-hour	--
KBPCF	Spot Filter - Byproduct Cyclone	$PM_{2.5}$	24-hour	0.007
			Annual	0.002
		PM_{10}	24-hour	0.007
		NOx	1-hour	--
			Annual	--
		CO	1-hour	--
			8-hour	--
NMC3F	Spot Filter - Kiln Tunnel	$PM_{2.5}$	24-hour	0.005
			Annual	0.001
		PM_{10}	24-hour	0.030
		NOx	1-hour	--
			Annual	--
		CO	1-hour	--
			8-hour	--
MBCF	Spot Filter - Micro Bin	$PM_{2.5}$	24-hour	0.001
			Annual	0.0001
		PM_{10}	24-hour	0.008
		NOx	1-hour	--
			Annual	--
		CO	1-hour	--
			8-hour	--
GVB1	Germination Vessel Boiler 1	$PM_{2.5}$	24-hour	0.015
			Annual	0.015
		PM_{10}	24-hour	0.015
		NOx	1-hour	0.060
			Annual	0.060
		CO	1-hour	0.168
			8-hour	0.168
GVB2	Germination Vessel Boiler 2	$PM_{2.5}$	24-hour	0.015
			Annual	0.015
		PM_{10}	24-hour	0.015
		NOx	1-hour	0.060

			Annual	0.060
		CO	1-hour	0.168
			8-hour	0.168
GVB4	Germination Vessel Boiler 4	$PM_{2.5}$	24-hour	0.015
			Annual	0.015
		PM_{10}	24-hour	0.015
		NOx	1-hour	0.060
			Annual	0.060
		CO	1-hour	0.168
			8-hour	0.168
GVB5	Germination Vessel Boiler 5	$PM_{2.5}$	24-hour	0.015
			Annual	0.015
		PM_{10}	24-hour	0.015
		NOx	1-hour	0.060
			Annual	0.060
		CO	1-hour	0.168
			8-hour	0.168
MAU1	Make Up Air Unit 1	$PM_{2.5}$	24-hour	0.017
			Annual	0.017
		PM_{10}	24-hour	0.017
		NOx	1-hour	0.219
			Annual	0.219
		CO	1-hour	0.184
			8-hour	0.184
MAU2	Make Up Air Unit 2	$PM_{2.5}$	24-hour	0.017
			Annual	0.017
		PM_{10}	24-hour	0.017
		NOx	1-hour	0.219
			Annual	0.219
		CO	1-hour	0.184
			8-hour	0.184
NMSBC1F	New Malt Storage Bins 1-5 Conveyor 1 Filter	$PM_{2.5}$	24-hour	0.005
			Annual	0.001
		PM_{10}	24-hour	0.030
		NOx	1-hour	--
			Annual	--
		CO	1-hour	--
			8-hour	--
NMSBC2F	New Malt Storage Bins 6-10 Conveyor 2 Filter	$PM_{2.5}$	24-hour	0.005
			Annual	0.001
		PM_{10}	24-hour	0.030
		NOx	1-hour	--
			Annual	--
		CO	1-hour	--
			8-hour	--
KS1	Kiln 1 Burner Stack (1)	$PM_{2.5}$	24-hour	0.059
			Annual	0.025
		PM_{10}	24-hour	0.059
		NOx	1-hour	0.287
			Annual	0.122
		CO	1-hour	1.758
			8-hour	1.758
KS2	Kiln 1 Burner Stack (2)	$PM_{2.5}$	24-hour	0.235

			Annual	0.101
		PM_{10}	24-hour	0.235
		NOx	1-hour	1.146
			Annual	0.490
		CO	1-hour	7.033
			8-hour	7.033
KS3	Kiln 1 Burner Stack (3)	$PM_{2.5}$	24-hour	0.059
			Annual	0.025
		PM_{10}	24-hour	0.059
		NOx	1-hour	0.287
			Annual	0.122
		CO	1-hour	1.758
			8-hour	1.758
KS4	Kiln 1 Burner Stack (4)	$PM_{2.5}$	24-hour	0.177
			Annual	0.075
		PM_{10}	24-hour	0.177
		NOx	1-hour	0.860
			Annual	0.367
		CO	1-hour	5.274
			8-hour	5.274
KS5	Kiln 1 Burner Stack (5)	$PM_{2.5}$	24-hour	0.059
			Annual	0.025
		PM_{10}	24-hour	0.059
		NOx	1-hour	0.287
			Annual	0.122
		CO	1-hour	1.758
			8-hour	1.758

[a.] Pound/hour emissions rate modeled is the potential/allowable emissions for the averaging period specified for the pollutant.
NOTE: These pound/hour emission rates are effective rates.

4.1.2 Modeled Emissions Rates for Cumulative Impact Analyses

__X__Emissions rates in Table11 are identical to those in the model input files for the cumulative NAAQS impact analyses. Also see Appendix E for a summary of GWM's modeled emission rates.

__X__Calculation of modeled emissions are thoroughly documented in this section (unless already described in Section 4.1.1), and any unique handling of emissions in the model have been described.

The new facility sources and existing sources as listed above in Table 8, constitute the GWM sources considered for the cumulative NAAQS modeling analyses. These emissions are also provided in DEQ's requested format below; Table 11 lists criteria pollutant emissions rates used in the cumulative NAAQS impact analyses for the GWM facility. The values in Table 11 are the representative pounds per hour emission rate for each new and existing source. The annual emission values, for example, were calculated by dividing the total pound per year emission rate by 8,760 hours. The daily emission rates were calculated by dividing the pound per day values by 24 hours. The hourly emission rates were used directly. These pounds per hour values for each averaging period were then converted to gram per second values for direct input to the modeling. A summary the modeling emission inventory for the facility is provided in Appendix E.

As requested by DEQ, the impacts from the nearby Simplot facility are considered in the cumulative NAAQS analyses and the criteria emission rates used in the cumulative NAAQS analysis are provided in Table 11. The values in Table 11 are the representative pounds per hour emission rate for each source at the Simplot facility from the 2014 emission inventory provided by Idaho DEQ. The annual values below were calculated by dividing the total annual emission rate by 8,760 hours. The short-term values were calculated by dividing the total annual emission rate by the actual hours each source operated. These values were then converted to grams per second for modeling.

Table 11. Modeled Emissions Rates for Cumulative NAAQS Impact Analyses (GWM Facility)

Source ID	Source Description	Pollutant	Averaging Period	Emissions (lb/hr)[a]
STC1F	Spot Filter - Barley to Steeps	$PM_{2.5}$	24-hour	0.005
			Annual	0.001
		PM_{10}	24-hour	0.030
		NOx	1-hour	--
			Annual	--
		CO	1-hour	--
			8-hour	--
STC2F	Spot Filter - Above Steeps	$PM_{2.5}$	24-hour	0.005
			Annual	0.001
		PM_{10}	24-hour	0.030
		NOx	1-hour	--
			Annual	--
		CO	1-hour	--
			8-hour	--
KB1	Kiln Air Heater 1 Burner Stack	$PM_{2.5}$	24-hour	0.135
			Annual	0.091

		PM_{10}	24-hour	0.135
		NOx	1-hour	0.655
			Annual	0.443
		CO	1-hour	4.018
			8-hour	4.018
KB2	Kiln Air Heater 2 Burner Stack	$PM_{2.5}$	24-hour	0.135
			Annual	0.091
		PM_{10}	24-hour	0.135
		NOx	1-hour	0.655
			Annual	0.443
		CO	1-hour	4.018
			8-hour	4.018
KB3	Kiln Air Heater 3 Burner Stack	$PM_{2.5}$	24-hour	0.135
			Annual	0.091
		PM_{10}	24-hour	0.135
		NOx	1-hour	0.655
			Annual	0.443
		CO	1-hour	4.018
			8-hour	4.018
KB4	Kiln Air Heater 4 Burner Stack	$PM_{2.5}$	24-hour	0.135
			Annual	0.091
		PM_{10}	24-hour	0.135
		NOx	1-hour	0.655
			Annual	0.443
		CO	1-hour	4.018
			8-hour	4.018
K2	Kiln 2 Exhaust	$PM_{2.5}$	24-hour	1.132
			Annual	0.997
		PM_{10}	24-hour	1.790
		NOx	1-hour	--
			Annual	--
		CO	1-hour	--
			8-hour	--
NMLF	Spot Filter - Analysis Bins Elevator	$PM_{2.5}$	24-hour	0.007
			Annual	0.001
		PM_{10}	24-hour	0.041
		NOx	1-hour	--
			Annual	--
		CO	1-hour	--
			8-hour	--
BA1F	Spot Filter - Analysis Bin W	$PM_{2.5}$	24-hour	0.007
			Annual	0.0003
		PM_{10}	24-hour	0.041
		NOx	1-hour	--
			Annual	--
		CO	1-hour	--
			8-hour	--
BA2F	Spot Filter - Analysis Bin E	$PM_{2.5}$	24-hour	0.007

			Annual	0.0003
		PM_{10}	24-hour	0.041
		NOx	1-hour	--
			Annual	--
		CO	1-hour	--
			8-hour	--
KBPCF	Spot Filter - Byproduct Cyclone	$PM_{2.5}$	24-hour	0.007
			Annual	0.002
		PM_{10}	24-hour	0.007
		NOx	1-hour	--
			Annual	--
		CO	1-hour	--
			8-hour	--
NMC3F	Spot Filter - Kiln Tunnel	$PM_{2.5}$	24-hour	0.005
			Annual	0.001
		PM_{10}	24-hour	0.030
		NOx	1-hour	--
			Annual	--
		CO	1-hour	--
			8-hour	--
MBCF	Spot Filter - Micro Bin	$PM_{2.5}$	24-hour	0.001
			Annual	0.0001
		PM_{10}	24-hour	0.008
		NOx	1-hour	--
			Annual	--
		CO	1-hour	--
			8-hour	--
GVB1	Germination Vessel Boiler 1	$PM_{2.5}$	24-hour	0.015
			Annual	0.015
		PM_{10}	24-hour	0.015
		NOx	1-hour	0.060
			Annual	0.060
		CO	1-hour	0.168
			8-hour	0.168
GVB2	Germination Vessel Boiler 2	$PM_{2.5}$	24-hour	0.015
			Annual	0.015
		PM_{10}	24-hour	0.015
		NOx	1-hour	0.060
			Annual	0.060
		CO	1-hour	0.168
			8-hour	0.168
GVB4	Germination Vessel Boiler 4	$PM_{2.5}$	24-hour	0.015
			Annual	0.015
		PM_{10}	24-hour	0.015
		NOx	1-hour	0.060
			Annual	0.060
		CO	1-hour	0.168
			8-hour	0.168

GVB5	Germination Vessel Boiler 5	$PM_{2.5}$	24-hour	0.015
			Annual	0.015
		PM_{10}	24-hour	0.015
		NOx	1-hour	0.060
			Annual	0.060
		CO	1-hour	0.168
			8-hour	0.168
MAU1	Make Up Air Unit 1	$PM_{2.5}$	24-hour	0.017
			Annual	0.017
		PM_{10}	24-hour	0.017
		NOx	1-hour	0.219
			Annual	0.219
		CO	1-hour	0.184
			8-hour	0.184
MAU2	Make Up Air Unit 2	$PM_{2.5}$	24-hour	0.017
			Annual	0.017
		PM_{10}	24-hour	0.017
		NOx	1-hour	0.219
			Annual	0.219
		CO	1-hour	0.184
			8-hour	0.184
NMSBC1F	New Malt Storage Bins 1-5 Conveyor 1 Filter	$PM_{2.5}$	24-hour	0.005
			Annual	0.001
		PM_{10}	24-hour	0.030
		NOx	1-hour	--
			Annual	--
		CO	1-hour	--
			8-hour	--
NMSBC2F	New Malt Storage Bins 6-10 Conveyor 2 Filter	$PM_{2.5}$	24-hour	0.005
			Annual	0.001
		PM_{10}	24-hour	0.030
		NOx	1-hour	--
			Annual	--
		CO	1-hour	--
			8-hour	--
EG1[b]	Emergency Generator	$PM_{2.5}$	24-hour	0.132
			Annual	0.002
		PM_{10}	24-hour	0.132
		NOx	1-hour[b]	--
			Annual	0.021
		CO	1-hour	0.401
			8-hour	0.401
BH1	Baghouse - Barley Head House	$PM_{2.5}$	24-hour	0.012
			Annual	0.003
		PM_{10}	24-hour	0.075
		NOx	1-hour	--
			Annual	--
		CO	1-hour	--

			8-hour	--
BH2	Baghouse - Malt & Barely Cleaning	$PM_{2.5}$	24-hour	0.012
			Annual	0.003
		PM_{10}	24-hour	0.149
		NOx	1-hour	--
			Annual	--
		CO	1-hour	--
			8-hour	--
BH3	Baghouse - Malt Cleaning, Loading & Transfer	$PM_{2.5}$	24-hour	0.014
			Annual	0.001
		PM_{10}	24-hour	0.100
		NOx	1-hour	--
			Annual	--
		CO	1-hour	--
			8-hour	--
BS1	Malt House Boilers Stack	$PM_{2.5}$	24-hour	0.048
			Annual	0.018
		PM_{10}	24-hour	0.048
		NOx	1-hour	0.625
			Annual	0.240
		CO	1-hour	0.525
			8-hour	0.525
BS2	Pellet Mill Boiler Stack	$PM_{2.5}$	24-hour	0.019
			Annual	0.019
		PM_{10}	24-hour	0.019
		NOx	1-hour	0.250
			Annual	0.250
		CO	1-hour	0.210
			8-hour	0.210
CS	Pellet Mill Cooler Stack	$PM_{2.5}$	24-hour	0.363
			Annual	0.224
		PM_{10}	24-hour	0.363
		NOx	1-hour	--
			Annual	--
		CO	1-hour	--
			8-hour	--
RB1	Rail Bay	$PM_{2.5}$	24-hour	0.044
			Annual	0.008
		PM_{10}	24-hour	0.253
		NOx	1-hour	--
			Annual	--
		CO	1-hour	--
			8-hour	--
RB2	Rail Bay	$PM_{2.5}$	24-hour	0.044
			Annual	0.008
		PM_{10}	24-hour	0.253
		NOx	1-hour	--
			Annual	--

		CO	1-hour	--
			8-hour	--
TB	Truck Bay	$PM_{2.5}$	24-hour	0.237
			Annual	0.021
		PM_{10}	24-hour	1.388
		NOx	1-hour	--
			Annual	--
		CO	1-hour	--
			8-hour	--
KSE01	Kiln 1 (1)	$PM_{2.5}$	24-hour	0.181
			Annual	0.160
		PM_{10}	24-hour	0.285
		NOx	1-hour	--
			Annual	--
		CO	1-hour	--
			8-hour	--
KSE02	Kiln 1 (2)	$PM_{2.5}$	24-hour	0.181
			Annual	0.160
		PM_{10}	24-hour	0.285
		NOx	1-hour	--
			Annual	--
		CO	1-hour	--
			8-hour	--
KSE03	Kiln 1 (3)	$PM_{2.5}$	24-hour	0.181
			Annual	0.160
		PM_{10}	24-hour	0.285
		NOx	1-hour	--
			Annual	--
		CO	1-hour	--
			8-hour	--
KSE04	Kiln 1 (4)	$PM_{2.5}$	24-hour	0.181
			Annual	0.160
		PM_{10}	24-hour	0.285
		NOx	1-hour	--
			Annual	--
		CO	1-hour	--
			8-hour	--
KSE05	Kiln 1 (5)	$PM_{2.5}$	24-hour	0.181
			Annual	0.160
		PM_{10}	24-hour	0.285
		NOx	1-hour	--
			Annual	--
		CO	1-hour	--
			8-hour	--
KS1	Kiln 1 Burner Stack (1)	$PM_{2.5}$	24-hour	0.059
			Annual	0.025
		PM_{10}	24-hour	0.059
		NOx	1-hour	0.287

			Annual	0.122
		CO	1-hour	1.758
			8-hour	1.758
KS2	Kiln 1 Burner Stack (2)	$PM_{2.5}$	24-hour	0.235
			Annual	0.101
		PM_{10}	24-hour	0.235
		NOx	1-hour	1.146
			Annual	0.490
		CO	1-hour	7.033
			8-hour	7.033
KS3	Kiln 1 Burner Stack (3)	$PM_{2.5}$	24-hour	0.059
			Annual	0.025
		PM_{10}	24-hour	0.059
		NOx	1-hour	0.287
			Annual	0.122
		CO	1-hour	1.758
			8-hour	1.758
KS4	Kiln 1 Burner Stack (4)	$PM_{2.5}$	24-hour	0.177
			Annual	0.075
		PM_{10}	24-hour	0.177
		NOx	1-hour	0.860
			Annual	0.367
		CO	1-hour	5.274
			8-hour	5.274
KS5	Kiln 1 Burner Stack (5)	$PM_{2.5}$	24-hour	0.059
			Annual	0.025
		PM_{10}	24-hour	0.059
		NOx	1-hour	0.287
			Annual	0.122
		CO	1-hour	1.758
			8-hour	1.758

[a.] Pound/hour emissions rate modeled is the potential/allowable emissions for the averaging period specified for the pollutant. NOTE: These pound/hour emission rates are effective rates.
[b.] Emissions from the emergency generator were not included in the 1-hour NO_2 analyses.

Table 12. Modeled Emissions Rates for Cumulative NAAQS Impact Analyses (Simplot Facility)

Source ID	Source Description	Pollutant	Averaging Period	Emissions (lb/hr)[a]
SIMP210	Granulation #1 Reactor/Granulator	$PM_{2.5}$	24-hour	0.78
			Annual	0.67
		PM_{10}	24-hour	0.78
		NOx	1-hour	--
			Annual	--
		CO	1-hour	--
			8-hour	--
SIMP220	Granulation #1 Dryer (Source ID 400, 406)	$PM_{2.5}$	24-hour	3.88
			Annual	3.35
		PM_{10}	24-hour	3.88
		NOx	1-hour	1.30
			Annual	1.13
		CO	1-hour	0.33
			8-hour	0.33
SIMP215	Granulation #1 Baghouse	$PM_{2.5}$	24-hour	0.36
			Annual	0.31
		PM_{10}	24-hour	0.36
		NOx	1-hour	--
			Annual	--
		CO	1-hour	--
			8-hour	--
SIMP241	Granulation #2 Dryer	$PM_{2.5}$	24-hour	2.07
			Annual	1.80
		PM_{10}	24-hour	2.07
		NOx	1-hour	1.20
			Annual	1.04
		CO	1-hour	0.38
			8-hour	0.38
SIMP250	Granulation #2 Baghouse (Source ID 461.1-470.3)	$PM_{2.5}$	24-hour	0.81
			Annual	0.71
		PM_{10}	24-hour	0.81
		NOx	1-hour	--
			Annual	--
		CO	1-hour	--
			8-hour	--
SIMP205	Granulation #3 (Source ID 700-720)	$PM_{2.5}$	24-hour	2.04
			Annual	1.22
		PM_{10}	24-hour	2.04
		NOx	1-hour	1.35
			Annual	0.81
		CO	1-hour	1.13
			8-hour	1.13
SIMP175	#400 Phosphoric Acid Plant (Faciltiy Source ID 200-226)	$PM_{2.5}$	24-hour	1.97
			Annual	1.89
		PM_{10}	24-hour	1.97
		NOx	1-hour	--
			Annual	--

		CO	1-hour	--
			8-hour	--
SIMP365	Super Phosphoric Acid Oxidizer (Source ID 1102-1113, 1506)	$PM_{2.5}$	24-hour	--
			Annual	--
		PM_{10}	24-hour	--
		NOx	1-hour	0.05
			Annual	0.05
		CO	1-hour	1.83
			8-hour	1.83
SIMP370	North Reclaim Cooling Tower Fan Exhaust	$PM_{2.5}$	24-hour	1.60
			Annual	1.54
		PM_{10}	24-hour	1.60
		NOx	1-hour	--
			Annual	--
		CO	1-hour	--
			8-hour	--
SIMP372	East Reclaim Cooling Tower Fan Exhaust	$PM_{2.5}$	24-hour	2.53
			Annual	2.43
		PM_{10}	24-hour	2.53
		NOx	1-hour	--
			Annual	--
		CO	1-hour	--
			8-hour	--
SIMP371	West Reclaim Cooling Tower Fan Exhaust	$PM_{2.5}$	24-hour	2.36
			Annual	2.27
		PM_{10}	24-hour	2.36
		NOx	1-hour	--
			Annual	--
		CO	1-hour	--
			8-hour	--
SIMP291	300 Sulfuric Acid Plant	$PM_{2.5}$	24-hour	6.98
			Annual	6.67
		PM_{10}	24-hour	6.98
		NOx	1-hour	3.51
			Annual	3.36
		CO	1-hour	--
			8-hour	--
SIMP295	#400 Sulfuric Acid Plant	$PM_{2.5}$	24-hour	4.03
			Annual	3.78
		PM_{10}	24-hour	4.03
		NOx	1-hour	8.31
			Annual	7.80
		CO	1-hour	--
			8-hour	--
SIMP195	Granulation #3 Limestone Bins	$PM_{2.5}$	24-hour	0.17
			Annual	0.13
		PM_{10}	24-hour	0.17
		NOx	1-hour	--
			Annual	--
		CO	1-hour	--
			8-hour	--

SIMP300	Ammonium Sulfate Dryer	$PM_{2.5}$	24-hour	0.25
			Annual	0.23
		PM_{10}	24-hour	0.25
		NOx	1-hour	0.07
			Annual	0.06
		CO	1-hour	0.02
			8-hour	0.02
SIMP310	Ammonium Sulfate Cooler	$PM_{2.5}$	24-hour	0.10
			Annual	0.09
		PM_{10}	24-hour	0.10
		NOx	1-hour	--
			Annual	--
		CO	1-hour	--
			8-hour	--
SIMP040	HPB&W Boiler	$PM_{2.5}$	24-hour	0.49
			Annual	0.12
		PM_{10}	24-hour	0.49
		NOx	1-hour	2.42
			Annual	0.62
		CO	1-hour	8.17
			8-hour	8.17
SIMP020	Babcock & Wilcox Boiler	$PM_{2.5}$	24-hour	0.22
			Annual	0.08
		PM_{10}	24-hour	0.22
		NOx	1-hour	2.95
			Annual	1.05
		CO	1-hour	2.48
			8-hour	2.48
SIMPFUG	Simplot Fugitive Sources	$PM_{2.5}$	24-hour	7.45
			Annual	7.03
		PM_{10}	24-hour	7.45
		NOx	1-hour	--
			Annual	--
		CO	1-hour	--
			8-hour	--

[a.] Pound/hour emissions rate modeled is the potential/allowable emissions for the averaging period specified for the pollutant. NOTE: These pound/hour emission rates are effective rates.

4.1.3 NO_2/NOx Ratio for NOx Chemistry Modeling

The San Joaquin Valley Air Pollution Control District (SJVAPCD) has provided recommended NO_2/NO_X in-stack ratios for a variety of source categories in the California Air Pollution Control Officers Association's (CAPCOA) guidance document for NO_2 1-hour modeling (CAPCOA 2011). The SJVAPCD recommends an NO_2/NO_X in-stack ratio of 10 percent for natural-gas-fired boilers. These values were used for all GWM combustion sources that burn natural-gas, including the kilns. Additional information from EPA's NO_2/NOx In-Stack Ratio (ISR) Database[1], which is provided in Appendix H, also supports the use of the 10 percent value.

Per DEQ's modeling protocol approval letter (dated November 5, 2015), DEQ accepts this NO_2/NOx ratio value as adequate for the natural-gas combustion sources at GWM.

For the competing sources at Simplot facility, the EPA-recommended NO_2/NO_X in-stack ratio of 20 percent was utilized for most sources with exception of the natural gas-fired competing sources where an in-stack ratio of 10 percent was utilized, consistent with the GWM NOx sources. NO_2/NO_X in-stack ratios used for both the GWM facility and Simplot facilities are presented in Table 13.

1 http://www3.epa.gov/scram001/no2_isr_database.htm

Table 13. Project-Wide NO_2/NO_X In-Stack Ratios

Source ID	NO_2/NO_X In-Stack Ratio	Facility
KB1	0.1	GWM
KB2	0.1	GWM
KB3	0.1	GWM
KB4	0.1	GWM
GVB1	0.1	GWM
GVB2	0.1	GWM
GVB4	0.1	GWM
GVB5	0.1	GWM
MAU1	0.1	GWM
MAU2	0.1	GWM
EG1	0.1	GWM
BS1	0.1	GWM
BS2	0.1	GWM
KS1	0.1	GWM
KS2	0.1	GWM
KS3	0.1	GWM
KS4	0.1	GWM
KS5	0.1	GWM
SIMP220	0.1	Simplot
SIMP241	0.1	Simplot
SIMP205	0.1	Simplot
SIMP365	0.2	Simplot
SIMP291	0.2	Simplot
SIMP295	0.2	Simplot
SIMP300	0.2	Simplot
SIMP040	0.2	Simplot
SIMP020	0.2	Simplot

4.1.4 Special Methods for Modeling Criterial Pollutant Emissions

The GWM modeling analyses do not require special handling of criteria pollutant emissions such as the use of an external emissions file to handle emissions that vary in a unique manner, varying emissions by a specified factor, use of multiple operating scenarios, or other unique methods of handling emissions.

4.2 Toxic Air Pollutants

___X__TAP emissions rates have been listed for each TAP that has project cumulative emissions exceeding the applicable EL.

__X__Emissions rates in Table X are identical to those in the model input file for TAP analyses.

Table 14 lists TAP emissions rates that were included in modeling analyses. The annual values listed in this table were calculated to be pounds per hour (annual average). The 24-hour values were derived by dividing the pounds per day emission rate by 24. These values were then converted to grams per second for modeling. Modeling was performed for each TAP having total project emissions exceeding the TAP-specific Screening Emissions Level.

Table 14. Modeled Emissions Rates for TAP Analyses

Source ID	Source Description	TAP	Averaging Period	Emissions (lb/hr)[a]
GV1-4[b]	Germination Vessels	Chlorine	24-hour	0.54
		Formaldehyde	Annual	--
GVB1	Germination Vessel Boiler 1	Chlorine	24-hour	--
		Formaldehyde	Annual	0.00003
GVB2	Germination Vessel Boiler 2	Chlorine	24-hour	--
		Formaldehyde	Annual	0.00003
GVB4	Germination Vessel Boiler 4	Chlorine	24-hour	--
		Formaldehyde	Annual	0.00003
GVB5	Germination Vessel Boiler 5	Chlorine	24-hour	--
		Formaldehyde	Annual	0.00003
KB1	Kiln Air Heater 1 Burner Stack	Chlorine	24-hour	--
		Formaldehyde	Annual	0.00030
KB2	Kiln Air Heater 2 Burner Stack	Chlorine	24-hour	--
		Formaldehyde	Annual	0.00030
KB3	Kiln Air Heater 3 Burner Stack	Chlorine	24-hour	--
		Formaldehyde	Annual	0.00030
KB4	Kiln Air Heater 4 Burner Stack	Chlorine	24-hour	--
		Formaldehyde	Annual	0.00030
MAU1	Make Up Air Unit 1	Chlorine	24-hour	--
		Formaldehyde	Annual	0.00004
MAU2	Make Up Air Unit 2	Chlorine	24-hour	--
		Formaldehyde	Annual	0.00004
KS1	Kiln 1 Burner Stack (1)	Chlorine	24-hour	--
		Formaldehyde	Annual	0.00013
KS2	Kiln 1 Burner Stack (2)	Chlorine	24-hour	--
		Formaldehyde	Annual	0.00053
KS3	Kiln 1 Burner Stack (3)	Chlorine	24-hour	--
		Formaldehyde	Annual	0.00013
KS4	Kiln 1 Burner Stack (4)	Chlorine	24-hour	--
		Formaldehyde	Annual	0.00040
KS5	Kiln 1 Burner Stack (5)	Chlorine	24-hour	--
		Formaldehyde	Annual	0.00013

a. Pound/hour emissions rate modeled is the potential/allowable emissions for the averaging period specified for the pollutant.
b. Emissions for the GV1-GV4 sources occur over a two hour period once a day. Chlorine is emitted a maximum for 2 hours/day from two GV stacks. For example, if considering the GV1 source, the daily chlorine emissions of 12.9 lb/day for GV1 were distributed evenly amongst two release points, GV1A, and GV2A during a given day. This allocation was performed for all GV1-4 sources (i.e., using GV1A/GV1B, GV2A/GV2B, etc. combinations) and the highest impacts from modeling were determined for each of the release combinations.
NOTE: These pound/hour emission rates are effective rates.

4.3 Emissions Release Parameters

___X___Thorough justification/documentation of release parameters for all modeled sources is provided in this section.

__X__The specific methods used to determine/calculate given release parameters is described in this section.

___X___The release orientation of all point source stacks (horizontal, rain-capped, or uninterrupted vertical release) has been verified and is documented in this section.

A description of the source characterization is provided below. The locations of the modeled sources (new and existing) are shown in Figure 2. Detailed documentation of stack temperature and flow rates is provided in Appendix F for all sources.

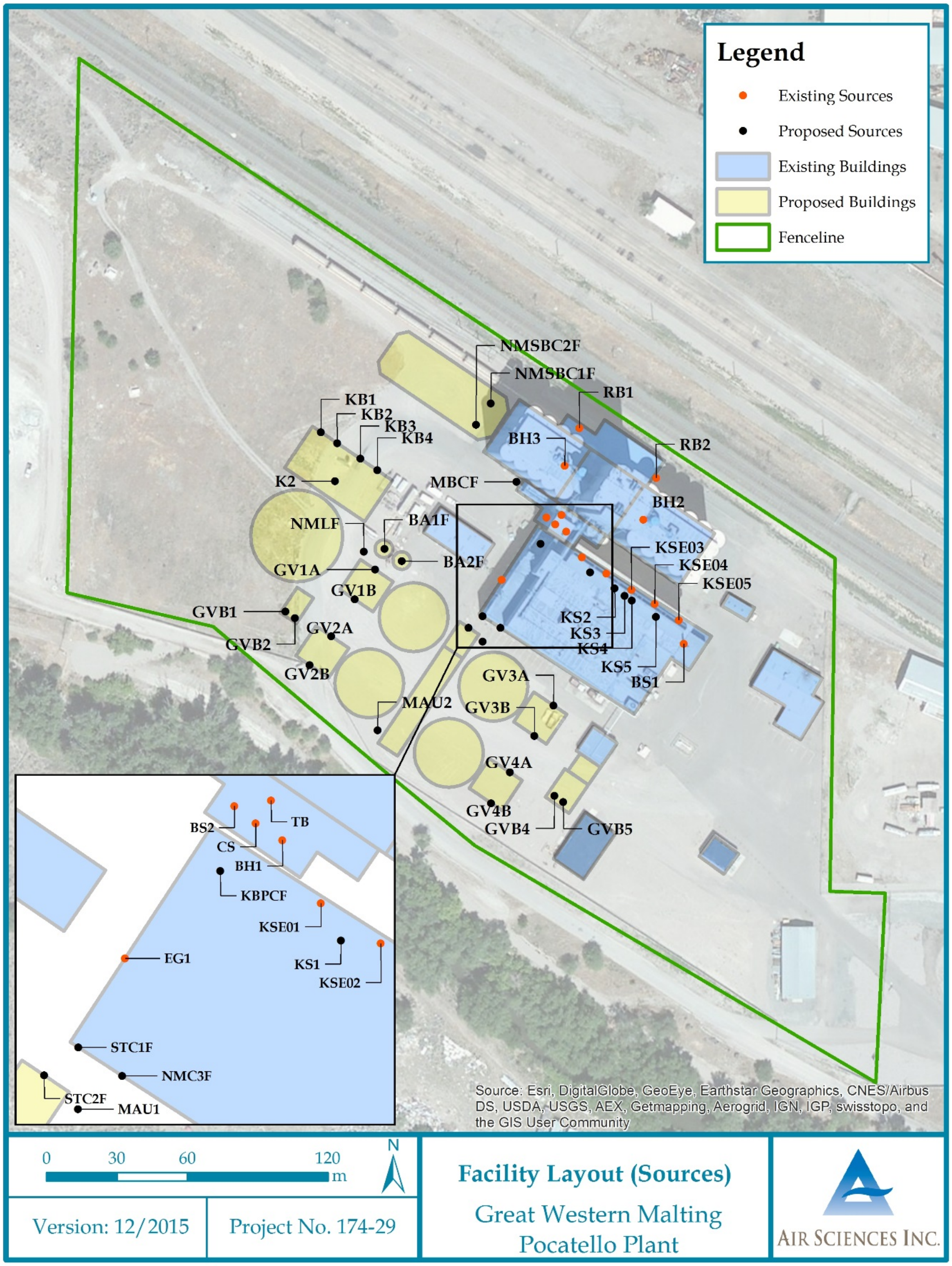
New Source Characterizations

The spot filters for the transfer of barley to the steeps and above the steeps (STC1F and STC2F, respectively) are located on the steep house and the existing malt house, respectively. Each spot filter stack was modeled as a POINT source with vertical release at ambient temperature. The kiln air heater burner stacks (KB1-KB4) as well as the kiln 2 exhaust (K2) stack are located within the kiln plenum building and were modeled as POINT sources. Each of these sources is a vertical stack that releases on the roof of the building. Six spot filters (NMLF, BA1F, BA2F, KBPCF, NMC3F, MBCF) located throughout the facility were modeled as POINT sources. The release points on each of the spot filters have vertical releases at ambient temperature. The malt kiln burner stacks (KS1-KS5) are located near the existing main kiln stack (KSE), but have their own explicit burner stacks. Currently, heat for the kiln is provided by ten natural gas-fired malt kiln burners that exhaust through the five malt kiln burner stacks (KS1-KS5). The burners for the existing kiln will be replaced with ten air-to-air heat exchangers to provide drying air to the kiln. The new heat exchangers will have ten natural gas-fired burners, one for each heat exchanger. The exhausts from the new burners will discharge through the five malt kiln burner stacks (KS1-KS5); KS1-KS5 are considered new sources for the purposes of the modeling analyses.

The germination vessel boiler stacks (GBV1-GBV6), located on either side of the germination plenums, were modeled as POINT sources with vertical releases. The makeup air units (MAU1 and MAU2), located near the steep house, were modeled as POINT sources with vertical releases at ambient temperature. The new malt storage bin conveyor filters (NMSBC1F and NMSBC2F), located at the malt storage bins, were modeled as POINT sources with vertical release orientations. The onsite emergency generator was modeled as a POINT source with a vertical release.

The four germination plenums (GV1A, GV1B, GV2A, GV2B, GV3A, GV3B, GV4A, and GV4B) will exhaust horizontally on two sides of each plenum. These sources were modeled as VOLUME sources following the AERMOD guideline: the initial sigma y was set to the length of each plenum divided by 4.3, and the initial sigma z is equal to each plenum height divided by 2.15.

Figure 2. Facility Layout Map (Sources)



Existing Source Characterizations

The three baghouses (BH1, BH2, and BH3) emit exhaust at a 45-degree angle downward toward the roof. Around two of the silo baghouses (BH2 and BH3), there is a three-sided, five-foot-high sound wall that blocks the exhaust flow. These three sources were modeled as POINT sources with horizontal exhausts with a height set to the roof height (not actual stack height).

The main malt kiln stack (KSE) is a long roof vent, which exhausts vertically. Similar to what was utilized for modeling the GWM facility in 2005, for the KSE source, the total malt kiln exhaust was modeled as five point sources, each with one-fifth of the exhaust area, volumetric flow rate, and emissions. This assumption is conservative since the plume merging effects were ignored. Emissions and source parameters from this source are derived from a previous source test.

The truck bay was modeled as a VOLUME source with the initial dispersion coefficients set according to the AERMOD guideline; that is, the initial sigma y was set to the length of the silo divided by 4.3, and the initial sigma z equal to the silos height divided by 2.15. This assumption is conservative for the truck bay since silos are between the source and the property line.

The rail bay is located on the property line side of the silos within an enclosed structure, with exposure to ambient air through the rail car entries. Thus, this source was split into two VOLUME sources, one on each side of the rail bay. The parameters of the VOLUME sources were set according to the AERMOD guideline based on the size of the rail bay, and not the silos. Thus, the initial sigma y was set to the width of the silo divided by 4.3, and the initial sigma z equal to the rail bay height divided by 2.15.

Treatment of Intermittent Emissions for 1-Hour Analyses

This section discusses the treatment of intermittent emissions for 1-hour analyses.

In its guidance on NO_2 1-hour modeling (EPA 2011), EPA has recognized that intermittent sources that do not operate continuously or frequently enough, specifically emergency generators, are less likely to contribute significantly to the annual distribution of daily maximum 1-hour values. EPA recommends "*that compliance demonstrations for the 1-hour NO_2 NAAQS be based on emission scenarios that can logically be assumed to be relatively continuous or which occur frequently enough to contribute significantly to the annual distribution of daily maximum 1-hour concentrations*" (EPA 2011).

The DEQ modeling guidelines further states that "*emissions sources that operate intermittently may be excluded from the SIL analysis and/or cumulative NAAQS analysis, approved by DEQ on a case-by-case basis, to the extent that it can be reasonably concluded that such sources could not measurably affect the compliance determination. If the intermittent sources are engines powering emergency generators or fire suppression water pumps, and operations are less than 100 hours/year for operational testing and maintenance, the sources can be excluded from compliance demonstrations for the 1-hour NO2 NAAQS, unless specifically required at the discretion of the DEQ Director*" (IDEQ 2013).

There is an emergency generator at GWM that will supply power to critical networks and equipment in the event that normal power supply is interrupted. The PTE for this generator is determined using 100 hours per year; however, it is expected to operate for even fewer hours and on a random schedule. Thus, the operation of the generator is not frequent enough to significantly contribute to the annual distribution of daily maximum 1-hour concentrations. As such, emissions from the emergency generator were not included in the NO_2 1-hour analyses.

Table 15 lists stack parameters for point sources and Table 16 lists release parameters for volume and area sources for both the GWM and Simplot facilities.

Table 15. Point Source Stack Parameters

Release Point	Description	UTM Coordinates		Stack Height (m)	Stack Gas Flow Temp. (K)[a]	Stack Gas Flow Velocity (m/sec)	Modeled Stack Diameter (m)	Orient. Of Release[c]
		Easting-X (m)	Northing-Y (m)					
GWM SOURCES								
STC1F	Spot Filter - Barley to Steeps	378,450	4,750,027	26.4	0.0	2.7	0.3	V
STC2F	Spot Filter - Above Steeps	378,444	4,750,022	28.2	0.0	2.7	0.3	V
KB1	Kiln Air Heater 1 Burner Stack	378,381	4,750,105	21.3	327.6	9.9	0.6	V
KB2	Kiln Air Heater 2 Burner Stack	378,388	4,750,101	21.3	327.6	9.9	0.6	V
KB3	Kiln Air Heater 3 Burner Stack	378,398	4,750,094	21.3	327.6	9.9	0.6	V
KB4	Kiln Air Heater 4 Burner Stack	378,405	4,750,089	21.3	327.6	9.9	0.6	V
K2	Kiln 2 Exhaust	378,387	4,750,084	20.4	310.9	3.3	13.9	V
NMLF	Spot Filter - Analysis Bins Elevator	378,400	4,750,054	1.8	0.0	14.0	0.3	V
BA1F	Spot Filter - Analysis Bin W	378,408	4,750,056	24.4	0.0	3.6	0.3	V
BA2F	Spot Filter - Analysis Bin E	378,416	4,750,050	24.4	0.0	3.6	0.3	V
KBPCF	Spot Filter - Byproduct Cyclone	378,475	4,750,058	27.4	0.0	3.6	0.3	V
NMC3F	Spot Filter - Kiln Tunnel	378,458	4,750,022	2.7	0.0	2.7	0.3	V
MBCF	Spot Filter - Micro Bin	378,465	4,750,084	15.2	0.0	0.9	0.3	V
GVB1	Germination Vessel Boiler 1	378,366	4,750,029	6.1	366.5	19.4	0.2	V
GVB2	Germination Vessel Boiler 2	378,370	4,750,026	6.1	366.5	19.4	0.2	V
GVB4	Germination Vessel Boiler 4	378,481	4,749,950	6.1	366.5	19.4	0.2	V

GVB5	Germination Vessel Boiler 5	378,485	4,749,947	6.1	366.5	19.4	0.2	V
MAU1	Make Up Air Unit 1	378,450	4,750,016	1.8	366.5	10.3	0.2	V
MAU2	Make Up Air Unit 2	378,405	4,749,978	1.8	366.5	10.3	0.2	V
NMSBC 1F	New Malt Storage Bins 1-5 Conveyor 1 Filter	378,454	4,750,118	27.4	0.0	2.7	0.3	V
NMSBC 2F	New Malt Storage Bins 6-10 Conveyor 2 Filter	378,447	4,750,109	27.4	0.0	2.7	0.3	V
KS1	Kiln 1 Burner Stack (1)	378,496	4,750,045	36.0	327.6	18.5	0.3	V
KS2	Kiln 1 Burner Stack (2)	378,507	4,750,039	36.0	327.6	27.8	0.4	V
KS3	Kiln 1 Burner Stack (3)	378,511	4,750,036	36.0	327.6	18.5	0.3	V
KS4	Kiln 1 Burner Stack (4)	378,514	4,750,034	36.0	327.6	20.9	0.4	V
KS5	Kiln 1 Burner Stack (5)	378,524	4,750,027	36.0	327.6	18.5	0.3	V
EG1	Emergency Generator	378,459	4,750,042	1.8	588.7	23.3	0.1	V
BS1	Malt House Boilers Stack	378,536	4,750,015	34.1	449.8	1.9	0.9	V
CS	Pellet Mill Cooler Stack	378,481	4,750,066	29.4	328.7	9.9	0.7	V
KSE01[c]	Kiln 1 (1)	378,493	4,750,052	31.7	299.3	1.6	6.3	V
KSE02[c]	Kiln 1 (2)	378,503	4,750,045	31.7	299.3	1.6	6.3	V
KSE03[c]	Kiln 1 (3)	378,514	4,750,038	31.7	299.3	1.6	6.3	V
KSE04[c]	Kiln 1 (4)	378,524	4,750,032	31.7	299.3	1.6	6.3	V
KSE05[c]	Kiln 1 (5)	378,534	4,750,025	31.7	299.3	1.6	6.3	V
BH1	Baghouse - Barley Head House	378,486	4,750,063	7.9	0.0	0.001	1.0	H
BH2	Baghouse - Malt & Barely Cleaning	378,519	4,750,068	41.1	0.0	0.001	1.0	H
BH3	Baghouse - Malt Cleaning, Loading & Transfer	378,485	4,750,091	41.1	0.0	0.001	1.0	H
BS2	Pellet Mill Boiler Stack	378,478	4,750,069	10.4	477.6	0.001	0.3	H

SIMPLOT SOURCES								
SIMP210	Granulation #1 Reactor/Granulator	375,350	4,751,839	29.9	351.0	17.5	0.9	V
SIMP220	Granulation #1 Dryer (Source ID 400, 406)	375,350	4,751,845	29.9	334.0	14.6	1.2	V
SIMP215	Granulation #1 Baghouse	375,353	4,751,844	29.9	327.0	13.0	0.8	V
SIMP241	Granulation #2 Dryer	375,338	4,751,773	45.7	333.0	12.4	1.8	V
SIMP250	Granulation #2 Baghouse (Source ID 461.1-470.3)	375,333	4,751,809	18.3	329.0	19.9	0.9	V
SIMP205	Granulation #3 (Source ID 700-720)	375,614	4,751,809	53.3	322.0	11.3	1.8	V
SIMP175	#400 Phosphoric Acid Plant (Faciltiy Source ID 200-226)	375,554	4,751,821	54.6	310.0	15.3	1.8	V
SIMP365	Super Phosphoric Acid Oxidizer (Source ID 1102-1113, 1506)	375,281	4,751,919	14.4	296.0	0.0	0.4	V
SIMP370	North Reclaim Cooling Tower Fan Exhaust	375,716	4,751,736	11.6	297.0	7.9	8.7	V
SIMP372	East Reclaim Cooling Tower Fan Exhaust	375,754	4,751,694	10.7	297.0	7.9	10.7	V
SIMP371	West Reclaim Cooling Tower Fan Exhaust	375,718	4,751,703	11.6	297.0	7.9	10.7	V
SIMP291	300 Sulfuric Acid Plant	375,222	4,751,946	61.6	294.9	27.4	1.4	V
SIMP295	#400 Sulfuric Acid Plant	375,209	4,751,745	64.0	346.2	9.3	2.9	V
SIMP195	Granulation #3 Limestone Bins	375,614	4,751,826	9.1	294.0	7.8	0.3	V
SIMP300	Ammonium Sulfate Dryer	375,359	4,751,781	23.2	308.0	15.1	0.5	V
SIMP310	Ammonium Sulfate Cooler	375,354	4,751,783	21.3	311.0	11.7	0.5	V
SIMP040	HPB&W Boiler	375,483	4,751,849	10.7	505.0	20.2	1.2	V
SIMP020	Babcock & Wilcox Boiler	375,491	4,751,866	13.7	505.0	15.0	1.2	V

[a.] Kelvin. NOTE: 0.0 K represents ambient release temperature.

[b.] Vertical uninterrupted, rain-capped, or horizontal release.

[c.] Similar to what was utilized for modeling the GWM facility in 2005, for the KSE source, the total malt kiln exhaust was modeled as five point sources, each with one-fifth of the exhaust area, volumetric flow rate, and emissions.

Table 16. Volume and Area Source Release Parameters

Source	Description	UTM Coordinates		Release Height (m)	Horizontal Dimension (m)	Vertical Dimension (m)
		Easting - X (m)	Northing - Y (m)			
GWM SOURCES						
GV1A	Germination Vessel 1, Exhaust A	378,404	4,750,047	6.1	3.6	4.1
GV1B	Germination Vessel 1, Exhaust B	378,396	4,750,034	6.1	3.6	4.1
GV2A	Germination Vessel 2, Exhaust A	378,386	4,750,018	6.1	3.6	4.1
GV2B	Germination Vessel 2, Exhaust B	378,376	4,750,006	6.1	3.6	4.1
GV3A	Germination Vessel 3, Exhaust A	378,481	4,749,989	6.1	3.6	4.1
GV3B	Germination Vessel 3, Exhaust B	378,472	4,749,976	6.1	3.6	4.1
GV4A	Germination Vessel 4, Exhaust A	378,462	4,749,960	6.1	3.6	4.1
GV4B	Germination Vessel 4, Exhaust B	378,454	4,749,947	6.1	3.6	4.1
RB1	Rail Bay (1)	378,492	4,750,107	17.2	6.3	16.0
RB2	Rail Bay (2)	378,524	4,750,086	17.2	6.3	16.0
TB	Truck Bay	378,484	4,750,070	17.2	11.8	16.0
SIMPLOT SOURCES						
SIMPFUG	Simplot Fugitive Sources	375,090	4,751,546	5	680	327

5.0 Modeling Methodology

This section describes the specific methods and data used in the air impact analyses.

Table 17 summarizes the key modeling parameters used in the impact analyses.

Table 17. Modeling Parameters

Parameter	Description/Values	Documentation/Addition Description
General Facility Location	Pocatello, Idaho	Facility location is in an attainment or not classifiable for all criteria pollutants (i.e., facility is not located in a non-attainment area).
Model	AERMOD	AERMOD with the PRIME downwash algorithm, version 04274.
Meteorological Data	24156 surface data 24131 upper air data	The meteorological model input files for this project were developed by DEQ. See Section 5.2 of this memorandum for additional details of the meteorological data.
Terrain	Considered	3-dimensional receptor coordinates were obtained from USGS National Elevation Dataset (NED) files and were used to establish elevation of ground level receptors. AERMAP was used to determine each receptor elevation and hill height scale.
Building Downwash	Considered	Plume downwash was considered for the structures associated with the GWM facility. BPIP-PRIME was used to evaluate building dimensions for consideration of downwash effects in AERMOD.
NOx Chemistry	OLM GROUP ALL	See Section 5.9 explaining the treatment of NOx chemistry.
Receptor Grid	**Significant Impact Analyses**	
	Grid 1	25-meter spacing along the ambient air boundary
	Grid 2	50-meter spacing in a 10,000 meter (easting) by 10,000 meter (northing) grid, centered on the facility where complex terrain exists.
	Grid 3	100-meter spacing in a 10,000 meter (easting) by 10,000 meter (northing) grid, centered on the facility where complex terrain does not exist.
	Grid 4	500-meter spacing between Grids 2 and 3 above, and 10,000 meter from the ambient air boundary.
	Grid 5	1,000-meter spacing between Grid 4 above, and 50,000 meter from the ambient air boundary.
	NAAQS Analyses	
	The same grid as above was used as the base grid to model for the NAAQS analysis. This base grid was then modified based on the significant impact analysis. The extent to which each pollutant was modeled for the NAAQS analysis was determined in accordance with DEQ/EPA guidance. The significant impact extents are presented below.	

	Pollutant	**NAAQS Analysis Receptor Extent**
	PM_{10} 24-hour	0.5-kilometer Radius from GWM
	$PM_{2.5}$ 24-hour & Annual	1.2-kilometer Radius from GWM
	NO_2 1-hour	Explicit Receptors Above SIL (Out to 15.4 kilometers)
	NO_2 Annual	0.6-kilometer Radius from GWM
	CO 1-hour & 8-hour	~0.01-kilometer Radius from GWM (only one GWM fenceline receptor above SIL)
	TAPs Analyses	
	The receptor grid used for the significant impact analysis (i.e., out to 50 km) was also used for the TAPs analysis.	

5.1 Model Selection

__X__The current versions of all models and associated programs were used in analyses, or alternate versions were specifically approved by DEQ.

__X__Any non-default model options used were approved by DEQ in advance.

DEQ approved GWM's use of the OLM GROUPALL method for NO_x chemistry using hourly ozone data from the Craters of the Moon National Monument. Further details regarding the treatment of NO_x chemistry in the modeling analysis are provided in Section 5.9 below.

Air dispersion models are a collection of mathematical algorithms packaged into a computer program to simulate the atmospheric dispersion of an air pollutant. Air dispersion models typically require source data (emissions, location, physical characteristics, etc.) and meteorological data (wind speed and direction, temperature, mixing height, etc.) to predict pollutant concentrations at downwind receptor locations, as a result of a source's emissions. These air dispersion models are widely used to assess changes in the ambient air resulting from a project's air emissions and to demonstrate compliance with applicable ambient air quality standards.

The modeling analysis was conducted using the most recent version as of the date of this protocol (version 15181) of the AERMOD (American Meteorological Society/ Environmental Protection Agency Regulatory Model) modeling system. AERMOD is an enhanced steady-state, Gaussian plume model that incorporates air dispersion based on planetary boundary layer turbulence structure and scaling concepts, including treatment of both surface and elevated sources, and both simple and complex terrain (EPA 2004). The AERMOD modeling system is listed as the recommended model for short-range analysis (up to 50 kilometers) in the United States Environmental Protection Agency (EPA)-maintained Guideline on Air Quality Models, which is published as Appendix W to the Code of Federal Regulations, Title 40, Part 51 (40 CFR 51, Appendix W).

AERMOD has been routinely used for air quality analyses of facilities located in Idaho and elsewhere and is the appropriate model selection for this analysis.

5.2 Meteorological Data

__X__ Meteorological data files are provided with the application.

_N/A_ If meteorological data used for modeling were not provided by DEQ, then a detailed discussion of the data is provided along with documentation of the processing steps.

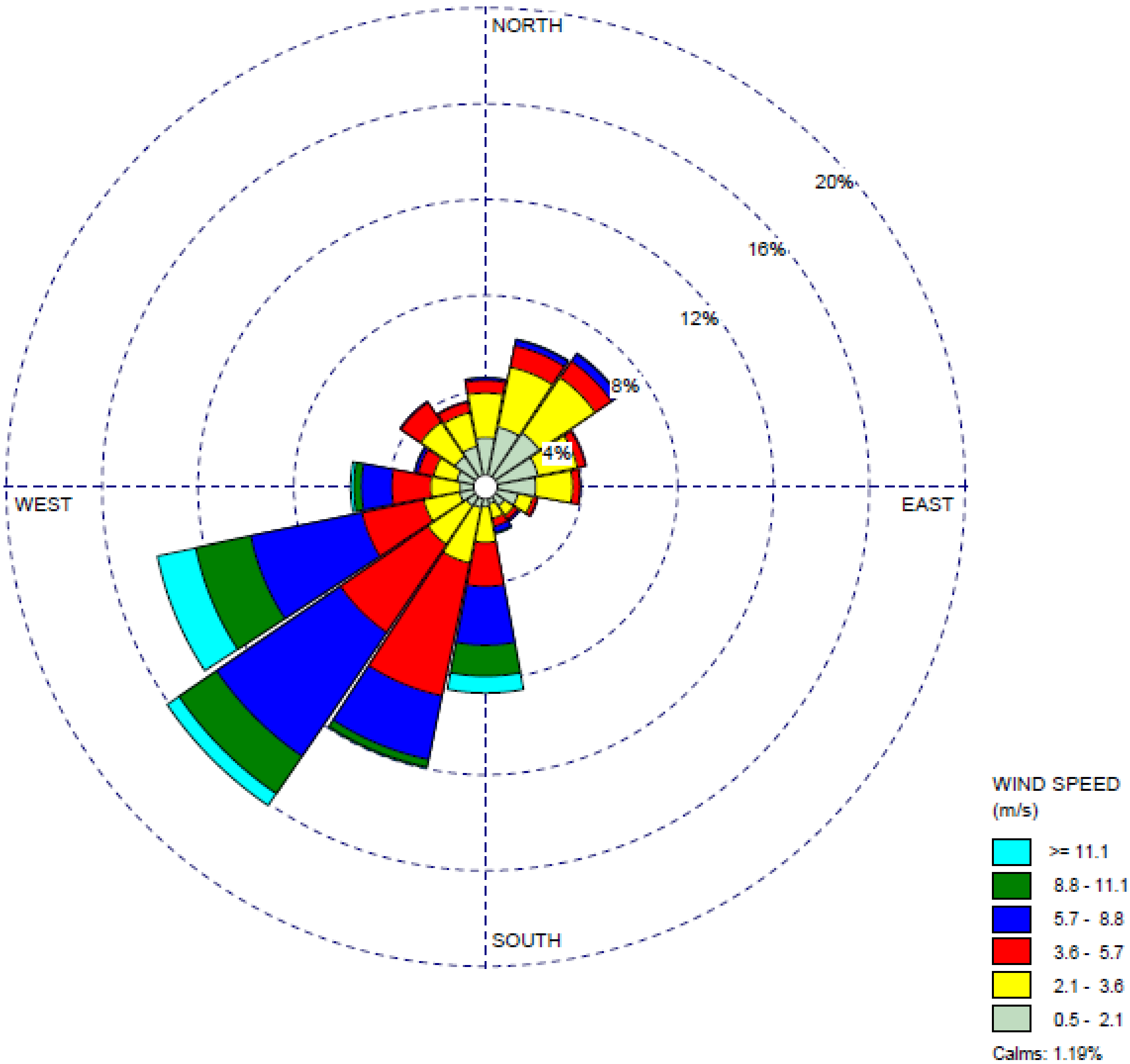
AERMOD requires the input of hourly meteorological data to estimate pollutant concentrations in the ambient air resulting from modeled source emissions. The EPA's Guideline on Air Quality Models (40 CFR 51, Appendix W) states that one year of site-specific data, or five years of representative hourly surface data, should be used for AERMOD dispersion modeling.

DEQ has provided GWM with five years (2008–2012) of AERMOD-ready meteorological data for modeling. The data provided are National Weather Service (NWS) surface meteorological data from the Pocatello Regional Airport in combination with upper-air data (soundings) from Boise, Idaho.

Please note that the AERMOD-ready meteorological data provided to GWM were processed using AERMET version 12345, not the most recent version of AERMET (version 15181). However, version 12345 data will still run in AERMOD version 15181.

The wind frequency distribution diagram for the Pocatello meteorological data set is shown in Figure 3.

Figure 3. Five-Year Wind Frequency Distribution Diagram for Pocatello (2008–2012)



5.3 Effects of Terrain

__X__The datum of terrain data, building corner locations, emissions sources, and the ambient air boundary are specified and are consistent such that the modeled plot plan accurately represents the facility and surroundings.

All receptors were processed with the AERMOD terrain preprocessor AERMAP (version 11103) to generate receptor terrain elevations and hill height values using 1/3-Arc-Second National Elevation Dataset (NED) elevation data obtained from the National Map Seamless Server[2] in a United States Geological Survey (USGS) GeoTIFF file format. All buildings and sources within the facility boundary were assigned a base elevation of 1350.26 meters (4,430 feet above sea level) to account for the level grade at the facility. This approach of assuming a level facility elevation base is consistent with the modeling approach of the GWM facility used for ISC modeling in 2005.

5.4 Facility Layout

__X__The facility layout plot plan is provided in this section that clearly and accurately depicts buildings, emissions points, and the ambient air boundary.

Please see Figure 2 in Section 4.3 for this information.

__X__This section of the Modeling Report has thoroughly described how locations of emissions sources, building corners, and the ambient air boundary were determined, specifying the datum used.

The Universal Transverse Mercator (UTM) coordinate system projected in North American Datum of 1983 (NAD83), Zone 12, was used in the air quality modeling analysis to define all locations in the modeling domain (sources, buildings, and receptors).

5.5 Effects of Building Downwash

All building information, source locations, and the ambient air boundary were characterized using a combination of aerial imagery and site maps and/or drawings. Sources were also located and characterized using site maps and drawings of the facility as well as aerial imagery of the facility. Existing buildings were characterized using a combination of aerial imagery and site drawings. New buildings were characterized using proposed site drawings. The ambient air boundary was determined using aerial imagery in combination with a site layout map that specified fencing and gates around the perimeter of the GWM facility. Figure 4 provides a plot showing the buildings considered in the BPIP analysis and their respective heights above grade.

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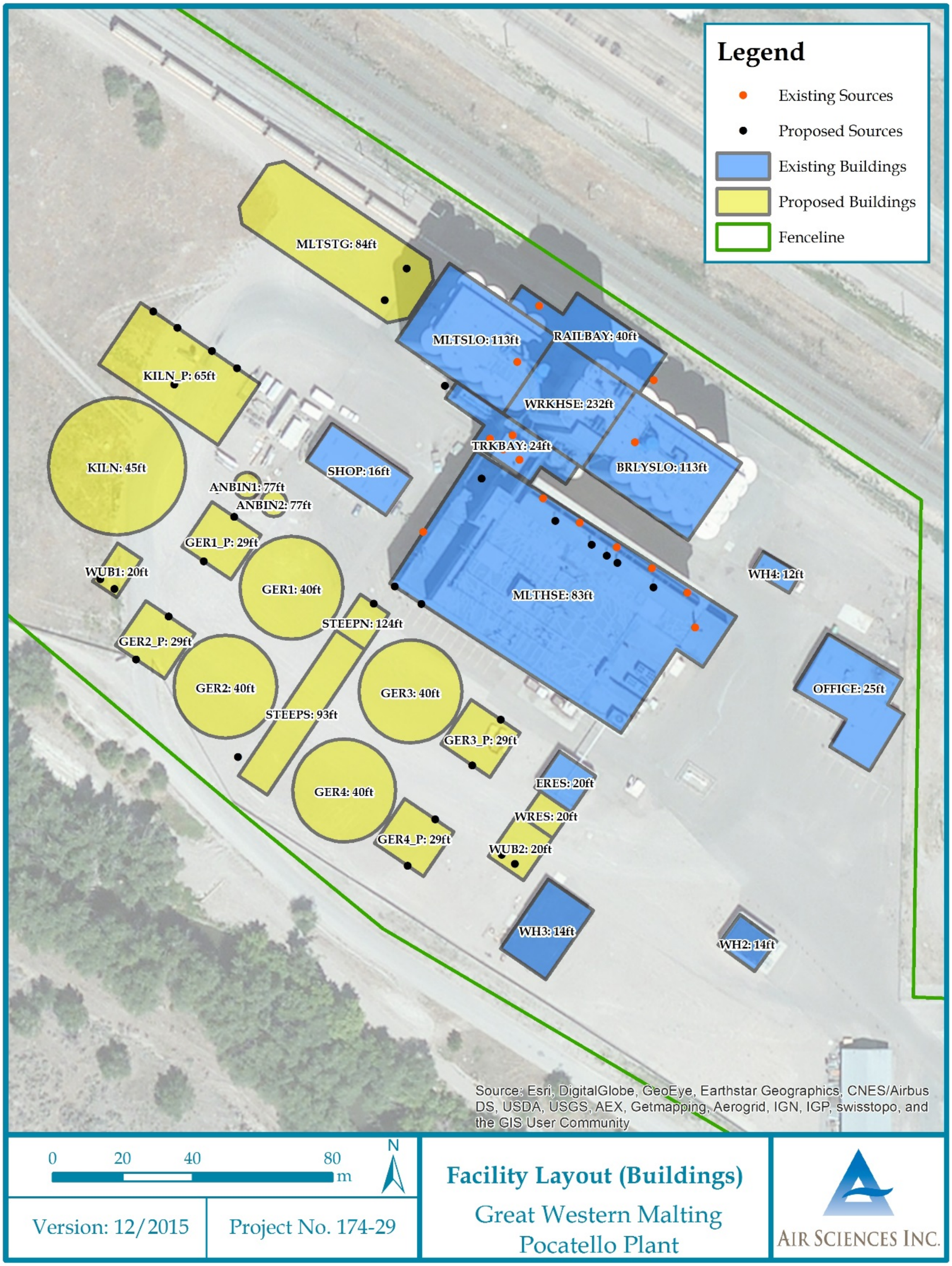
[2] http://www.mrlc.gov

Figure 4. Facility Layout Map (Buildings)



5.6 Ambient Air Boundary

_N/A_ If any of the following apply, the effect on areas excluded from ambient air is thoroughly described in this section: a river/stream bisecting the facility; the facility is on leased property or is leasing property to another entity; the facility is not completely fenced; there are right-of-way areas on the facility; the nature of business is such that the general public have access to part or all of the facility.

__X__ This section thoroughly describes how the facility can legally preclude public access (and practically preclude access) to areas excluded from ambient air in the modeling analyses.

See Figure 2 in Section 4.3 for a plot of the GWM fence line relative to the GWM sources and buildings. The ambient air boundary denoted by the fence line is located around the GWM facility where public access is restricted through a combination of fences, gates, and signage. Receptors within the ambient air boundary were not modeled.

5.7 Receptor Network

__X__ This section of the Modeling Report provides justification that receptor spacing used in the air impact analyses was adequate to reasonably resolve the maximum modeled concentrations to the point that NAAQS or TAP compliance is assured.

Consistent with previous modeling of the facility, receptors were placed along the property line (ambient air boundary) with a spacing of at least 25 meters. For receptors within 1 kilometer of the facility and for receptors in complex terrain to the southwest of the facility, 50-meter grid spacing was used. A grid spacing of 100 meters was used for receptors out to 5 kilometers from the facility. Finally, for the significant impacts analyses, the grid was extended to include 500-meter grid spacing to 10 kilometers from the facility and 1,000-meter grid spacing between 10 and 50 kilometers from the facility to define the significant impact areas. The near-field receptors are shown in Figure 5. The far-field receptors are shown in Figure 6.

Because of downwash and relatively cool exhausts, the maximum impacts from the GWM facility are located on the ambient air boundary where receptors were spaced at 25-meter intervals, assuring that maximum modeled impacts from the project were captured.

Figure 5. Near-Field Receptors for Significant Impact Analysis and TAP Analysis

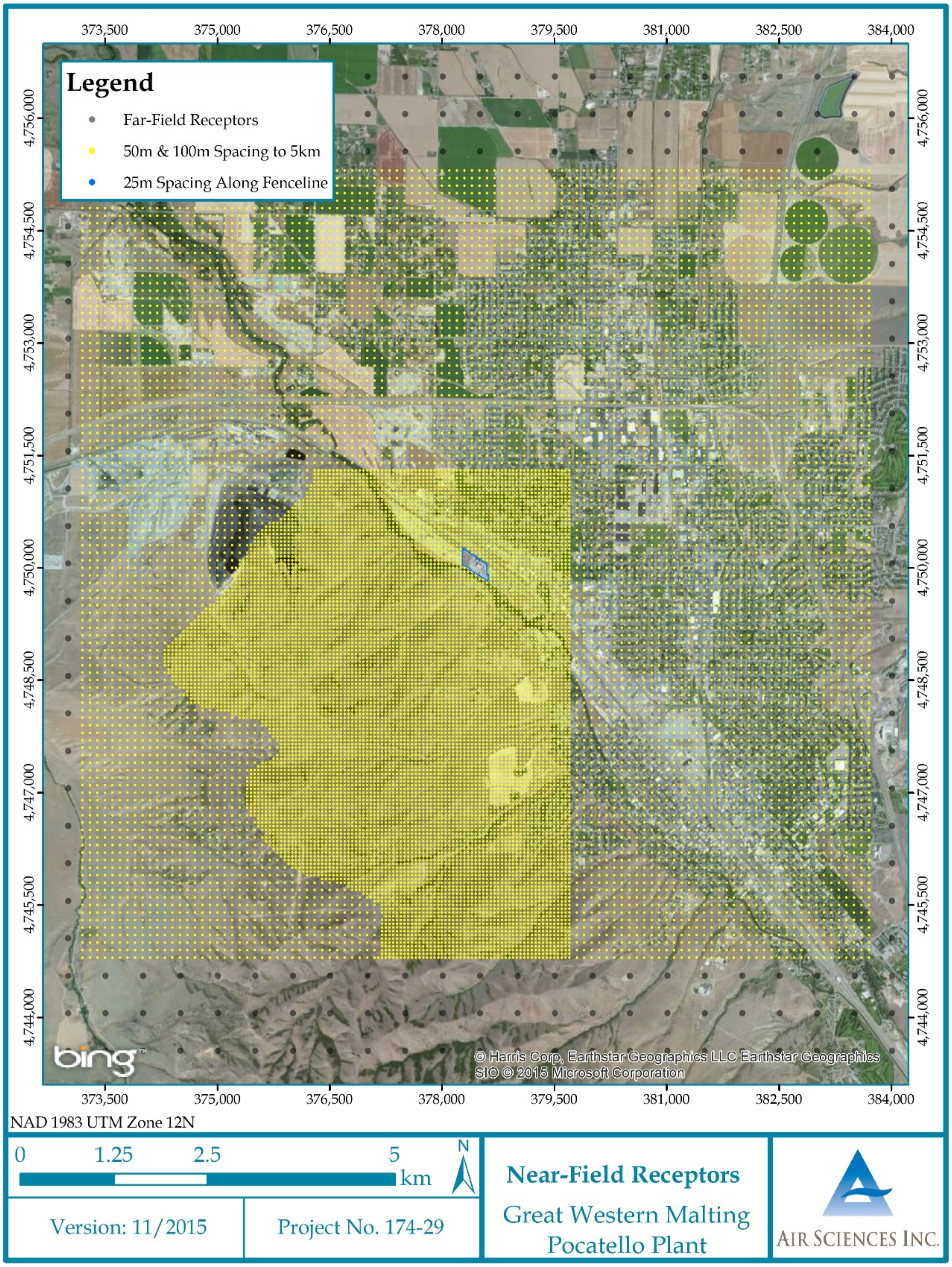
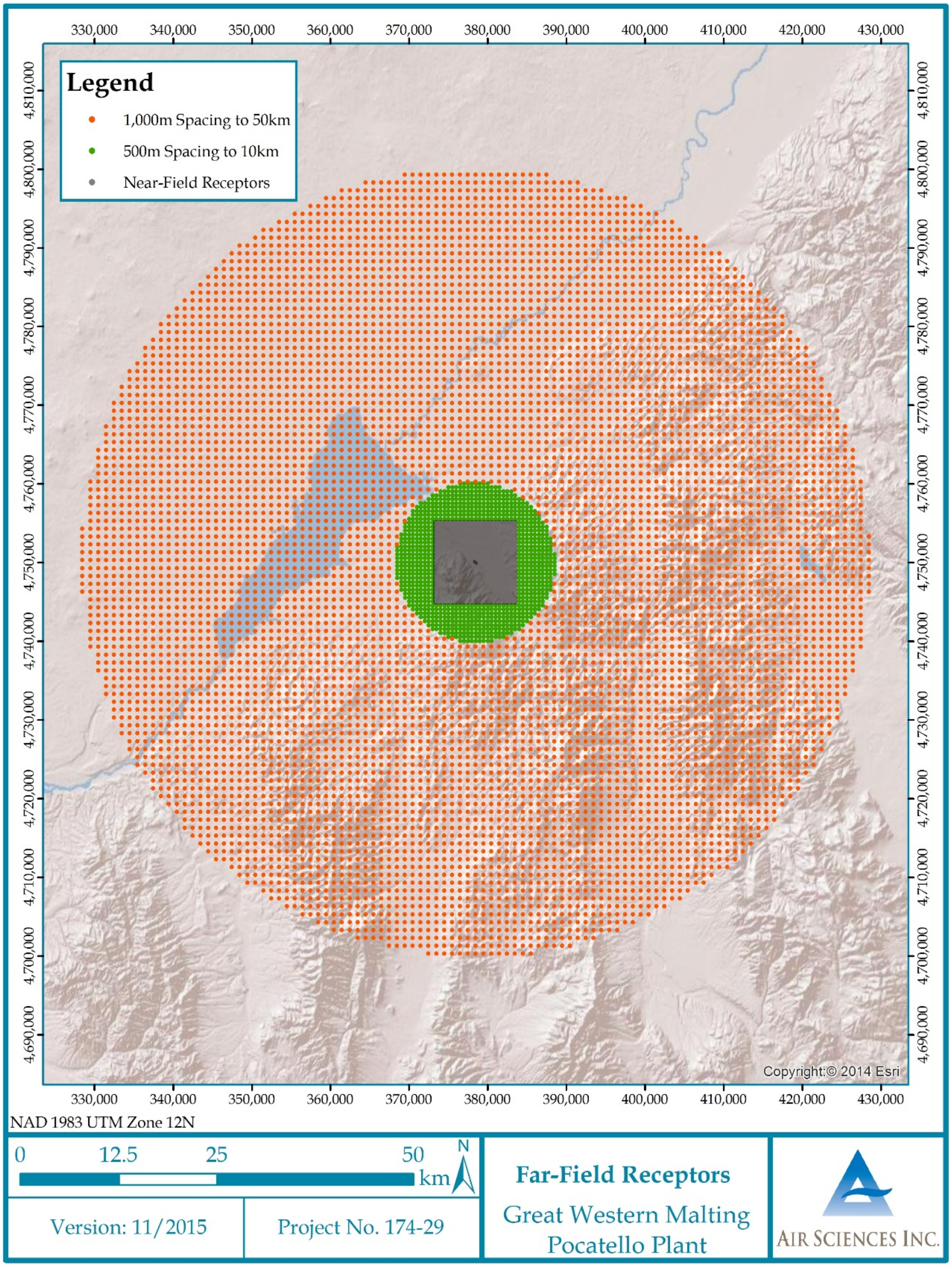


Figure 6. Far-Field Receptors for Significant Impact Analysis and TAP Analysis



5.8 Background Concentrations

__X__ Background concentrations have been thoroughly documented and justified for all criteria pollutants where a cumulative NAAQS impact analysis was performed.

Monitored pollutant concentrations, or background concentrations, are considered to be representative of the prevailing air pollution from the existing sources in the region. These background concentrations are added to the modeled ambient impacts from project emissions to estimate the total ambient concentrations at the modeled receptor locations.

DEQ has provided GWM background concentrations to be used in the NAAQS analysis as shown in Table 18. GWM will utilize the single background values above for the NAAQS compliance demonstration. If it is necessary to refine the background concentrations to demonstrate compliance (i.e., by season or time of day), GWM will discuss further with DEQ.

Table 18. Background Concentrations for Compliance Demonstration

Pollutant	Averaging Period	Background Concentration ($\mu g/m^3$)
CO	1-hour	3,306
	8-hour	1,118
NO_2	1-hour	60.2
	Annual	9.0
$PM_{2.5}$	24-hour	12.0
	Annual	4.3
PM_{10}	24-hour	72.0

5.9 NOx Chemistry

___X___If the Ozone Limiting Method (OLM) or the plume volume molar ratio method PVMRM were used to address NO_x chemistry, reasons for selecting one algorithm over the other are provided in this section.

GWM provided DEQ detailed information regarding NOx chemistry and its proposed treatment with AERMOD in the original modeling protocol (see Appendix C) and in a modeling protocol addendum #1 provided in Appendix D. This information and GWM's approach to NO_x chemistry is provided below.

Regulatory default options in AERMOD were used to estimate the ground-level concentrations for all the pollutants and averaging periods except for NO_2, which is detailed in the following subsection.

The NO_X emissions from combustion sources are principally composed of nitrogen oxide (NO) and NO_2. Once in the atmosphere, the NO is converted to NO_2 through a chemical reaction with ambient O_3, as follows:

$$NO + O_3 \rightarrow NO_2 + O_2$$

Currently, EPA's Guideline on Air Quality Models (40 CFR 51, Appendix W), presents a three-tiered approach to convert annual NO_X (nitrogen oxides) impacts to annual NO_2 impacts for comparison to the annual NO_2 NAAQS. In EPA memoranda dated June 28, 2010, and March 1, 2011 (EPA 2010 and EPA 2011), the applicability of 40 CFR 51, Appendix W is further discussed in the context of modeling for compliance with the 1-hour NO_2 standard. To address the atmospheric conversion process, EPA recommends the following three-tiered screening approach for evaluating NO_2 impacts:

- Tier 1: Assume total conversion of NO to NO_2.
- Tier 2: Assume representative equilibrium NO_2/NO_X ratio (0.75 for annual and 0.80 for 1-hour).
- Tier 3: A detailed screening method may be used on a case-by-case basis.

The non-default option of the Ozone Limiting Method (OLM), a Tier 3 method from 40 CFR 51, Appendix W, was used to estimate the NO_2 1-hour and annual impacts for this analysis. The OLM determines the limiting factor for NO_2 formation by comparing the estimated maximum NO_X concentration and the ambient O_3 concentration. The model assumes a total NO to NO_2 conversion when the ambient O_3 concentration is greater than the estimated maximum NO_X concentration; otherwise it is limited by the ambient O_3 concentration.

It should be noted that AERMOD NO_2 concentrations can be simulated using either OLM or PVMRM. However, EPA guidance (EPA 2011) indicates that preliminary model evaluation results show that the PVMRM option in AERMOD is not inherently superior to the OLM for purposes of estimating cumulative NO_2 concentrations. According to EPA (EPA 2011):

> *"The PVMRM algorithm as currently implemented may also have a tendency to overestimate the conversion of NO to NO_2 for low-level plumes by overstating the amount of ozone available for the conversion due to the manner in which the plume volume is calculated. The plume volume calculation in PVMRM does not account for the fact that the vertical extent of the plume based on*

the vertical dispersion coefficient may extend below ground for low-level plumes. This overestimation of the volume of the plume could contribute to overestimating conversion to NO_2."

In addition, results of monitor-to-monitor comparisons from recent studies show generally good results with the use of OLM with the combined plume option OLM (keywords OLMGROUP ALL).

Given PVMRM's tendency to over-predict NO_2 concentrations, the combined plume option (keywords OLMGROUP ALL) of the OLM is appropriate and was used for this analysis. Key model inputs for both the OLM option in AERMOD are the in-stack ratios of NO_2/NO_X emissions and background ozone concentrations.

Additional input parameters for the OLM option include the following:

- Background O_3 Concentrations – The use of the PVMRM or OLM option in AERMOD requires the input of background O_3 concentrations. The O_3 concentration values may be input as a single value, as hourly values to correspond with the meteorological data, or as a temporally varying profile.
- Ambient Equilibrium NO_2/NO_X Ratio – The AERMOD default NO_2/NO_X ambient equilibrium ratio of 0.90 was used for this analysis.
- In-Stack NO_2/NO_X Ratio – The San Joaquin Valley Air Pollution Control District (SJVAPCD) has provided recommended NO_2/NO_X in-stack ratios for a variety of source categories in the California Air Pollution Control Officers Association's (CAPCOA) guidance document for NO_2 1-hour modeling (CAPCOA 2011). The SJVAPCD recommends an NO_2/NO_X in-stack ratio of 10 percent for natural-gas-fired boilers. These values were used for all GWM combustion sources that burn natural-gas, including the kilns. Information from EPA's NO_2/NOx In-Stack Ratio (ISR) Database[3], which is provided in Appendix H, also supports the use of this 10 percent value.

To demonstrate modeled NO_2 compliance of the facility, GWM utilized a Tier 3 (NO_2) modeling approach (OLMGROUP ALL) using hourly ozone data from nearby Craters of the Moon National Monument. EPA characterizes a Tier 3 modeling approach as a general category of "detailed screening methods" which may be considered on a case-by-case basis.

EPA recommends the use of the OLM/OLMGROUP ALL method and states in their guidance memo "Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-Hour NO_2 National Ambient Air Quality Standard" (EPA 2011) that:

"…preliminary results of hourly NO_2 predictions for Palaau and New Mexico show generally good performance for the PVMRM and OLM/OLMGROUP ALL options in AERMOD. We believe that these additional model evaluation results lend further credence to the use of these Tier 3 options in AERMOD for estimating hourly NO_2 concentrations, and we recommend that their use should be generally accepted provided some reasonable demonstration can be made of the appropriateness of the key inputs for these options, the in-stack NO_2/NOx ratio and the background ozone concentrations."

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[3] http://www3.epa.gov/scram001/no2_isr_database.htm

The use of the OLM option in AERMOD requires the input of background O_3 concentrations and in-stack NO_2/NOx ratios. The O_3 concentration values may be input as a single value, as hourly values to correspond with the meteorological data, or as a temporally varying profile. For this analysis, DEQ has initially provided GWM a single design concentration background ozone concentration (58 ppb) derived from the NW Airquest database using a model-monitor interpolation process for data from 2009 through 2011. However, EPA notes in their guidance memo "Applicability of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard" (EPA 2010) that:

> *"Both OLM and PVMRM rely on the same key inputs of in-stack NO_2/NOx ratios and hourly ambient ozone concentrations. Although both methods can be applied within the AERMOD model using a single "representative" background ozone concentration, it is likely that use of a single value would result in very conservative estimates of peak hourly ambient concentrations since its use for the 1-hour NO_2 standard would be contingent on a demonstration of conservatism for all hours modeled."*

This is exactly this level of conservatism (e.g. single value for ozone) that GWM is facing. Thus, GWM utilized the Tier 3 method with concurrent hourly ozone to address this conservatism. GWM believes the use of hourly ozone data is supported by EPA guidance (EPA 2010) as an integral part of a Tier 3 NO_2 analysis methodology outlined by EPA.

EPA has raised three issues regarding the use of hourly ozone data for NO_2 modeling:

1) the hourly monitored ozone concentrations used with the Tier 3 OLM and PVMRM options must be concurrent with the meteorological data period),

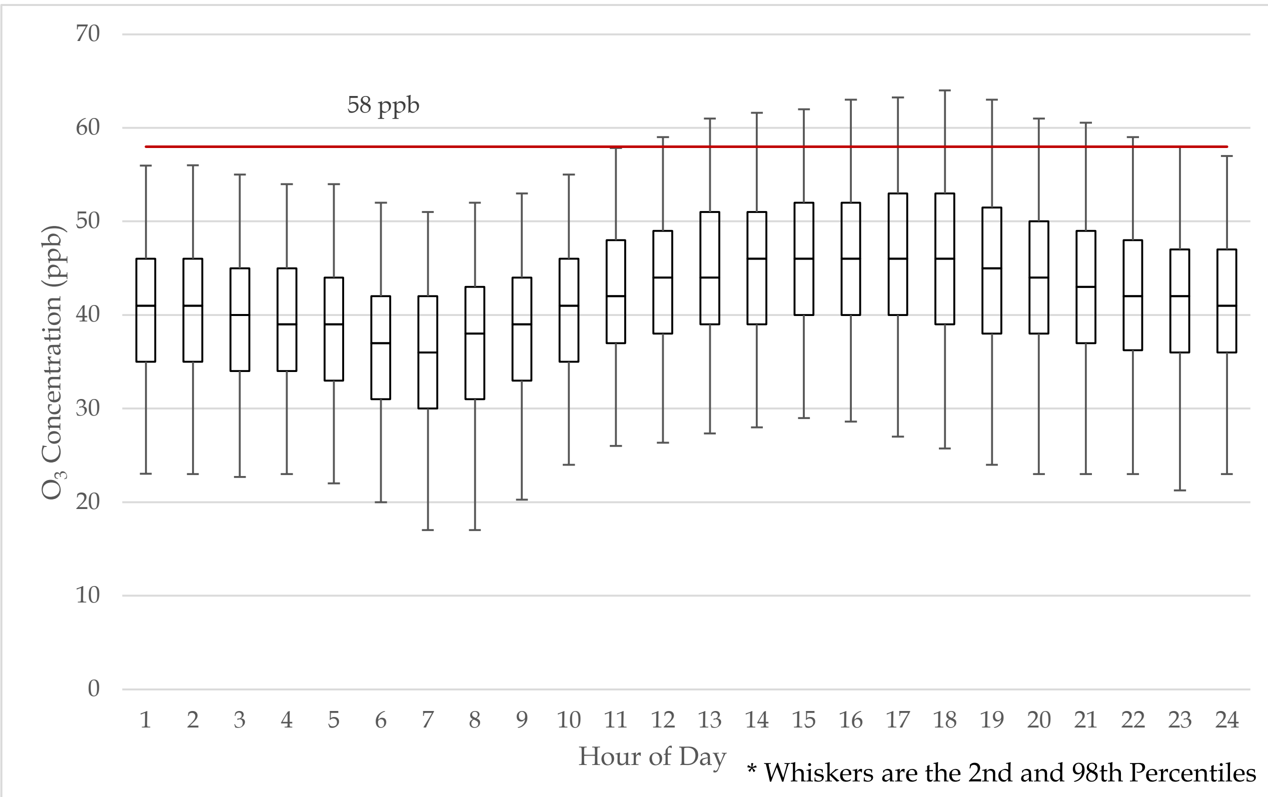
2) that the data are appropriately filled, and

3) the ozone monitor be sufficiently far from any local NOx emission sources to avoid any bias due to NOx scavenging.

The Craters of the Moon National Monument ozone dataset is a high quality ozone data set available from the National Park Service. Craters of the Moon National Monument is concurrent with the five years of meteorological data to be used for AERMOD modeling. Because there are few nearby sources of NOx emissions in the vicinity of the Craters of the Moon ozone monitor, the Craters of the Moon ozone data is would not be subject to ozone scavenging from local NO_X emission sources. Thus, the data set provides a representative temporal ozone concentration for the GWM project. Furthermore, GWM used the DEQ-provided NW Airquest 58 ppb ozone value to conservatively fill any hours of missing Craters of the Moon ozone data.

Figure 7 presents a box-and-whisker plot of the range of hourly ozone concentrations measured at Craters of the Moon by time of day for five years (2008-2012) concurrent with the meteorological dataset to be used for modeling. The lower and upper whiskers represent the 2^{nd} and 98^{th} percentile concentrations respectively, the lower box spans the 25^{th} to 50^{th} percentile, and the upper box spans 50^{th} to 75^{th} percentile. The DEQ provided ozone value of 58 ppb value is indicated by a red line in Figure 7 and is the same magnitude as the upper percentile ozone concentrations measured at Craters of the Moon data set. As expected, the hourly ozone concentrations vary throughout the day and are lowest during the early morning hours and higher during the later afternoon daytime hours when photochemical reactions create ozone. This pattern is ignored when a single value for the ozone concentration is used, thus over predicting NO_2 conversion in the night and early morning hours, especially during the morning hours when GWM's 1-hour NO_2 modeled impacts are the highest. GWM asserts that the use of hourly ozone data in the GWM modeling analysis is a necessary refinement to capture realistic diurnal patterns and ozone concentrations representative of the GWM modeling domain.

Figure 7. Box-and-Whisker Plot of Hourly Ozone Concentrations by Time of Day - Craters of the Moon



6.0 Results and Discussion

6.1 Criteria Pollutant Impact Results

Based on the results provided in Table 19, the GWM facility is in compliance with the NAAQS for all modeled criteria pollutants.

Table 19. Criteria Pollutant NAAQS Impact Results

Pollutant	Averaging Period	Modeled (µg/m³)	Background (µg/m³)	Total (µg/m³)	NAAQS (µg/m³)	Exceed NAAQS?
Nitrogen Dioxide (NO_2)	1-hour [1]	109.2	60.2	169.4	188	No
	Annual [2]	8.9	9.0	17.9	100	No
Fine Particulate Matter ($PM_{2.5}$)	24-hour [4]	21.8	12.0	33.8	35	No
	Annual [5]	6.2	4.3	10.5	12	No
Particulate Matter (PM_{10})	24-hour [3]	69.2	72.0	141.2	150	No
Carbon Monoxide (CO)	1-hour [6]	1,964.8	3,306	5,270.8	40,000	No
	8-hour [6]	351.6	1,118	1,469.6	10,000	No

[1] Modeled value presented is the highest-eighth-highest max daily 1-hour value averaged over five-years on a receptor-by-receptor basis.

[2] Highest modeled annual average concentration over five years.

[3] Highest-sixth-highest modeled concentrations over 5-years of meteorological data.

[4] Five-year average of the highest-eight-highest max daily modeled concentrations on a receptor-by-receptor basis.

[5] Five-year average of the annual modeled concentrations on a receptor-by-receptor basis.

[6] Maximum of highest-second-highest concentrations.

6.1.1 Significant Impact Level Analyses

__X__Model input and output files for SIL analyses have been provided with the application, with descriptions of the analyses associated with those files.

AERMOD was run for the facility, and for competing sources (as needed), and the modeled impact added to the background concentration for comparison to the NAAQS. For the new sources as part of the expansion project, chlorine and formaldehyde impacts (without addition of background concentrations, which are assumed negligible) were compared to the AAC and AACC, respectively.

For comparison to significant impact levels, AERMOD was run for the expansion project sources (new sources) for each pollutant and averaging time. If the maximum impact was less than the applicable SIL, then the analysis was assumed completed for that pollutant and averaging time. If the pollutant impact exceeded the SIL, a full impact analysis was conducted, which includes impacts from both new and existing sources at the GWM facility and nearby sources (i.e., the Simplot facility).

Initially, the SIA is determined for every relevant averaging time for a particular pollutant. The final SIA for that pollutant is the largest area for each of the various averaging times. According to the EPA's Draft New Source Review Workshop Manual (EPA 1990), the SIA is a circular area with a radius extending from the source to: 1) the most distant point where approved dispersion modeling predicts a significant ambient impact will occur, or 2) a modeling receptor distance of 50 kilometers, whichever is less. Therefore, a SIA cannot be greater than 50 kilometers for any pollutant. The SIA radius for GWM was limited to 50 kilometers because that is the upper limit of AERMOD's regulatory range and EPA has clarified that an SIA radius should not exceed 50 kilometers.

For the 1-hour NO_2 SIA, following EPA guidance, the receptors to be considered for the 1-hour NO_2 analyses are based on the explicit receptors that have a multi-year average impact greater than the SILs, rather than a traditional impact area based on a circular radius.

Table 20 provides DEQ-requested information related to Class II SIAs from the GWM expansion project. Although not requested in DEQ's table, the results of the SIA analysis indicate GWM SIAs (as measured from the center of the GWM facility) of: 0.6 km for NO_2 (annual), 1.2 km for $PM_{2.5}$, 0.5 km for PM_{10}, and ~0.01 km for CO (only one GWM fenceline receptor above SIL for CO). For the 1-hour NO_2 SIA analysis, explicit receptors above the 1-hour NO_2 SIL value were determined and any receptors located within the Simplot facility were excluded. The resulting receptor set was considered in the cumulative NAAQS model runs.

Table 20. Results for Significant Impact Analyses

Pollutant	Averaging Period	Maximum Modeled Concentration (μg/m^3)[a]	Significant Contribution Level (μg/m^3)	Impact Percentage of Significant Contribution Level	Cumulative NAAQS Analysis Required
$PM_{2.5}$[b]	24-hour[g]	8.0	1.2	664%	Yes
	Annual[g]	2.0	0.3	678%	Yes
PM_{10}[c]	24-hour	11.9	5	238%	Yes
NO_2[d]	1-hour[g]	122.8	7.5	1638%	Yes
	Annual	7.6	1	755%	Yes
CO[e]	1-hour	2179.1	2,000	109%	Yes
	8-hour	459.5	500	92%	Yes

a. Micrograms/cubic meter

b. Particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers.

c. Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers.

d. Nitrogen dioxide.

e. Carbon Monoxide.

6.1.2 Cumulative NAAQS Impact Analyses

__X__Model input and output files for the cumulative NAAQS impact analyses are provided with the application.

__N/A__If there were modeled NAAQS violations, all violations were analyzed and clearly show that the project did not significantly contribute to those modeled violations. If there were multiple violations at a given receptor, all cumulative impacts (including background) for the averaging period analyzed were ranked along with the project contribution, and the project contributions were below the applicable SIL. A table was included to show all ranked impacts above the NAAQS along with the project contribution. There are not NAAQS violations and all cumulative impacts are less than the NAAQS.

Table 21 provides results of cumulative NAAQS impact analyses and Figure 8 through Figure 11 show the locations of the maximum modeled impacts from the cumulative NAAQS impact analyses. For all modeled pollutants and their respective averaging periods, the maximum impact locations are on the GWM facility fence line (25-meter spaced receptors).

For the cumulative 1-hour NO_2 NAAQS modeling analyses, the SIL receptors extend into the Simplot facility. For receptors on the Simplot property that were over the SIL, an additional analysis was performed where only GWM sources were modeled, and GWM's modeled impacts were determined on Simplot's property. The results of this analysis indicate that maximum modeled 1-hour NO_2 impacts from all GWM sources on the Simplot property are 22.2 $\mu g/m^3$ plus the background concentration of 60.2 $\mu g/m^3$ for a total modeled impact of 82.4 $\mu g/m^3$, much less than the 1-hour NO_2 NAAQS of 188 $\mu g/m^3$. GWM's 1-hour NO_2 impacts on the Simplot facility property are a small fraction of the NAAQS.

Table 21. Results for Cumulative NAAQS Impact Analyses

Pollutant	Averaging Period	Modeled Design Concentration (μg/m³)[a]	Background Concentration (μg/m³)	Total Impact (μg/m³)	NAAQS (μg/m³)
$PM_{2.5}$[b]	24-hour[g]	21.8	12.0	33.8	35
	Annual[h]	6.2	4.3	10.5	12
PM_{10}[c]	24-hour[i]	69.2	72.0	141.2	150
NO_2[d]	1-hour[g]	109.2	60.2	169.4	188
	Annual	8.9	9.0	17.9	100
CO[f]	1-hour[j]	1,964.8	3,306.0	5,270.8	40,000
	8-hour[j]	351.6	1,118.0	1,469.6	10,000

a. Micrograms/cubic meter
b. Particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers.
c. Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers.
d. Nitrogen dioxide.
e. Sulfur dioxide.
f. Carbon Monoxide.
g. Maximum of 5-year means (or a lesser averaging period if less than 5 years of meteorological data were used in the analyses) of 8th highest modeled concentrations for each year modeled.
h. Maximum of 5-year means (or a lesser averaging period if less than 5 years of meteorological data were used in the analyses) of maximum modeled concentrations for each year modeled.
i. Maximum of 6th highest modeled concentrations for a 5-year period (or the maximum of the 2nd highest modeled concentrations if only 1 year of meteorological data are modeled).
j. Maximum of 2nd highest modeled concentrations for each year modeled.

Figure 8. Map of Locations of $PM_{2.5}$ Maximum Modeled Impacts from NAAQS Analysis

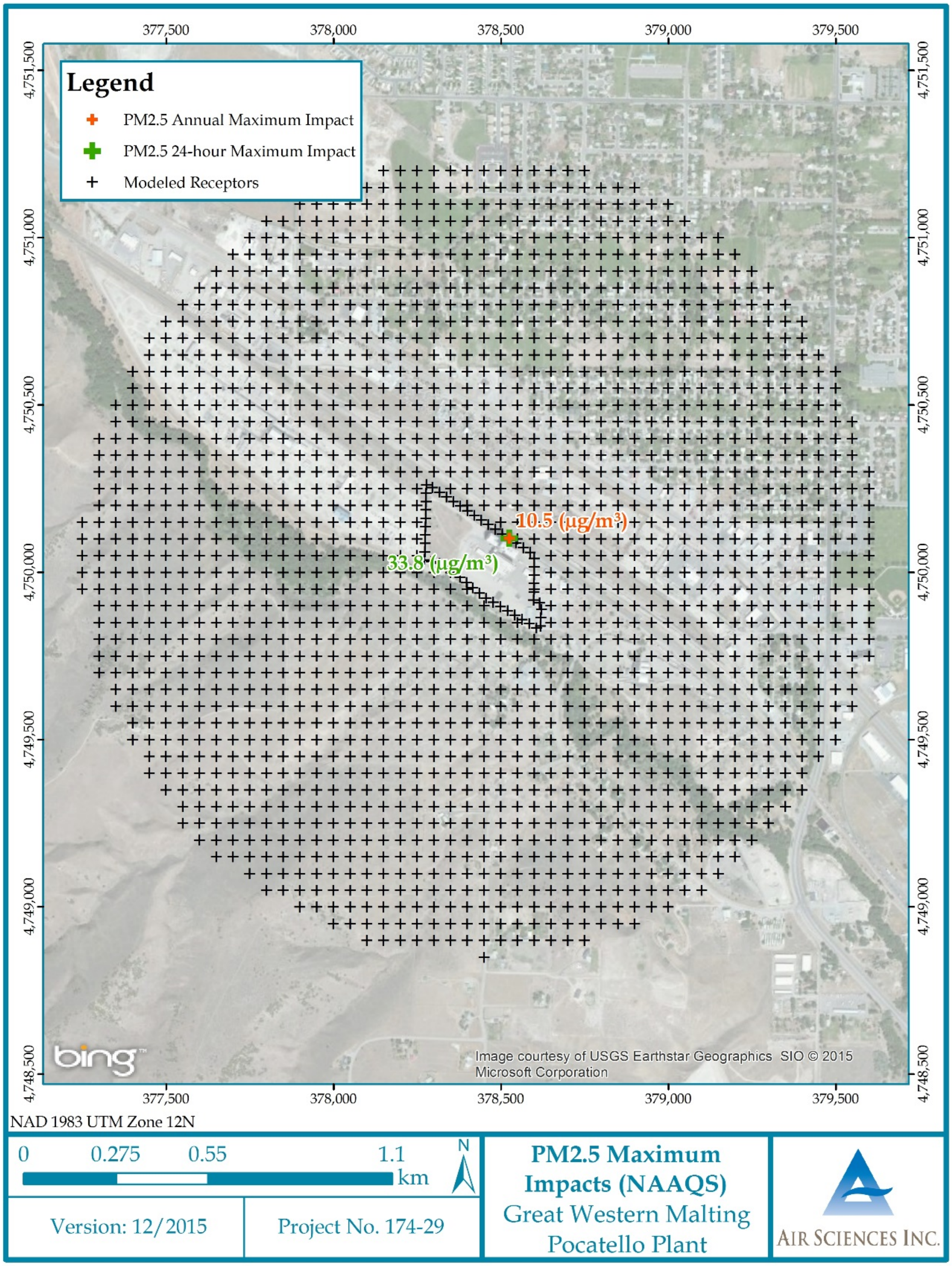


Figure 9. Map of Location of PM_{10} 24-hour Maximum Modeled Impact from NAAQS Analysis

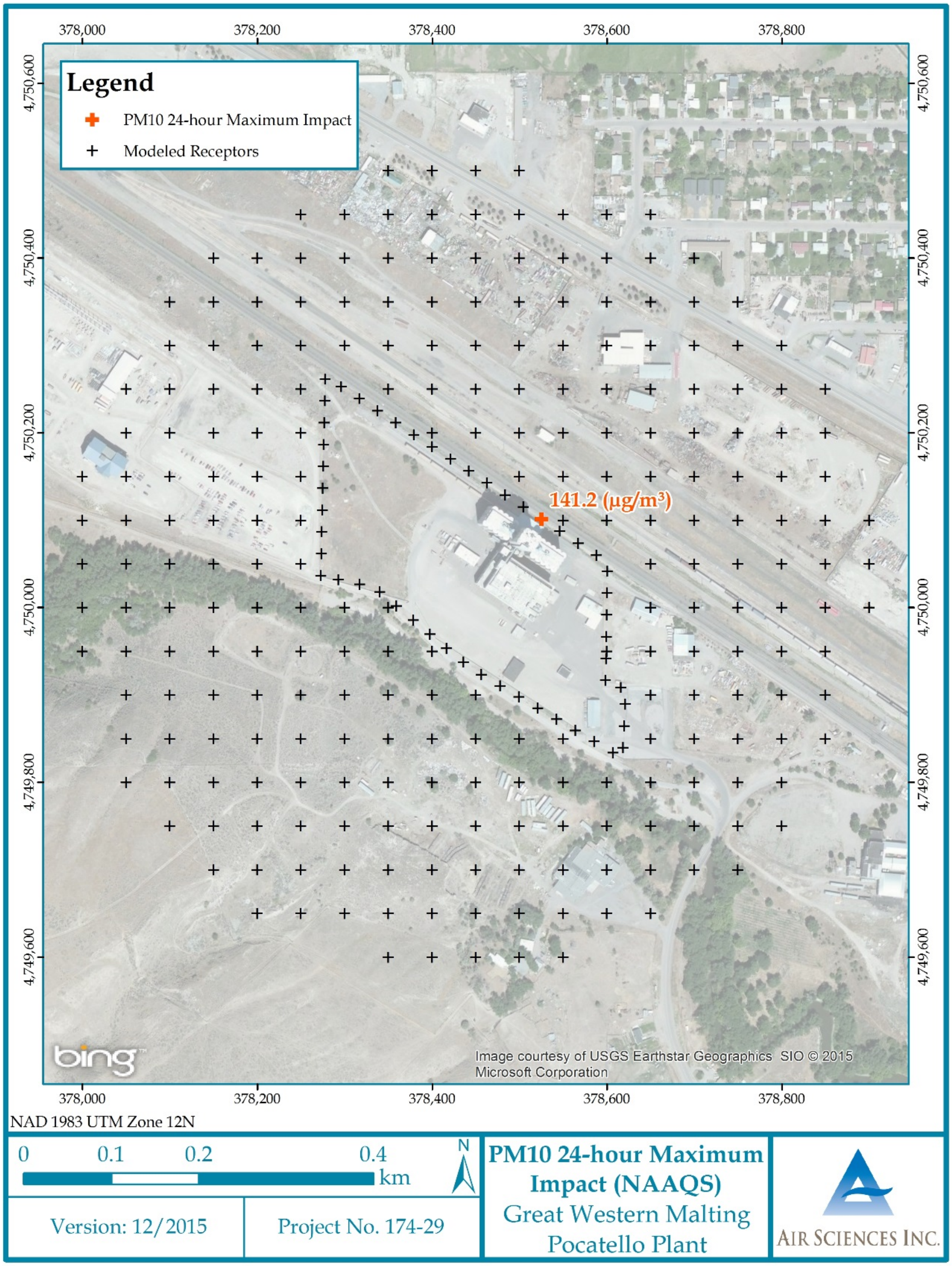


Figure 10. Map of Location of NO_2 1-hour Maximum Modeled Impact from NAAQS Analysis

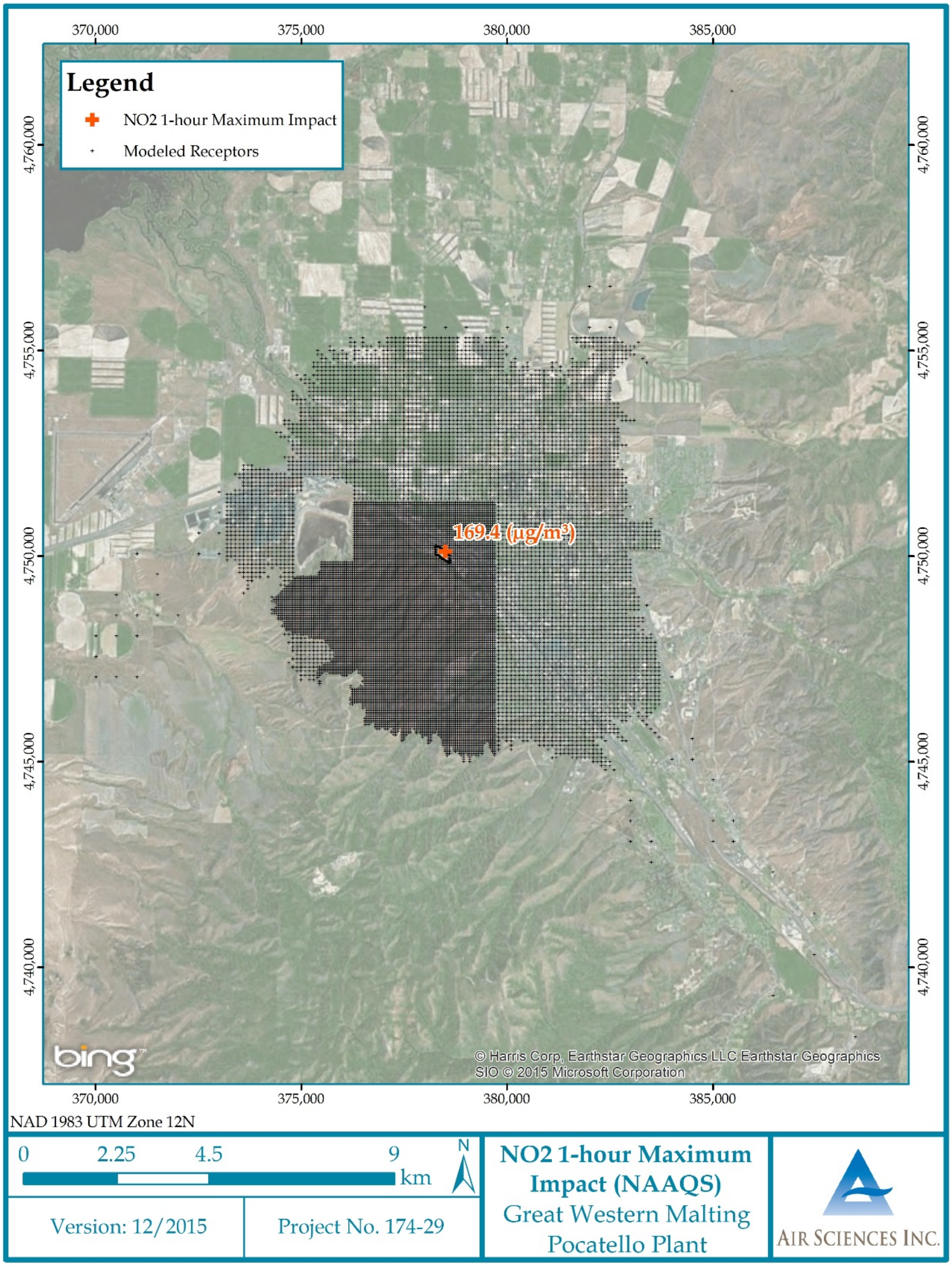


Figure 11. Map of Location of NO_2 Annual Maximum Modeled Impact from NAAQS Analysis

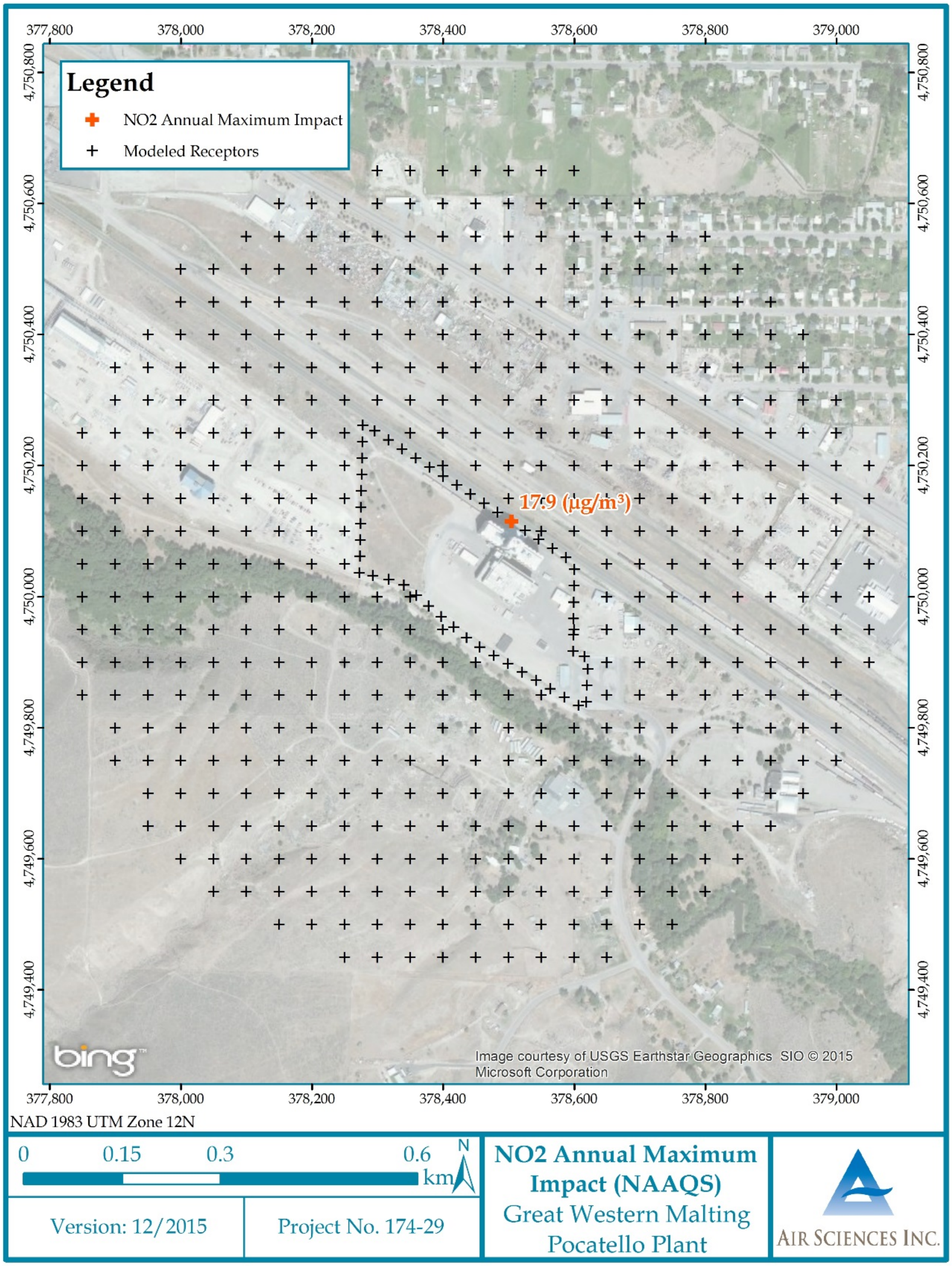


Figure 12. Map of Location of CO Annual Maximum Modeled Impact from NAAQS Analysis

6.2 TAP Impact Analyses

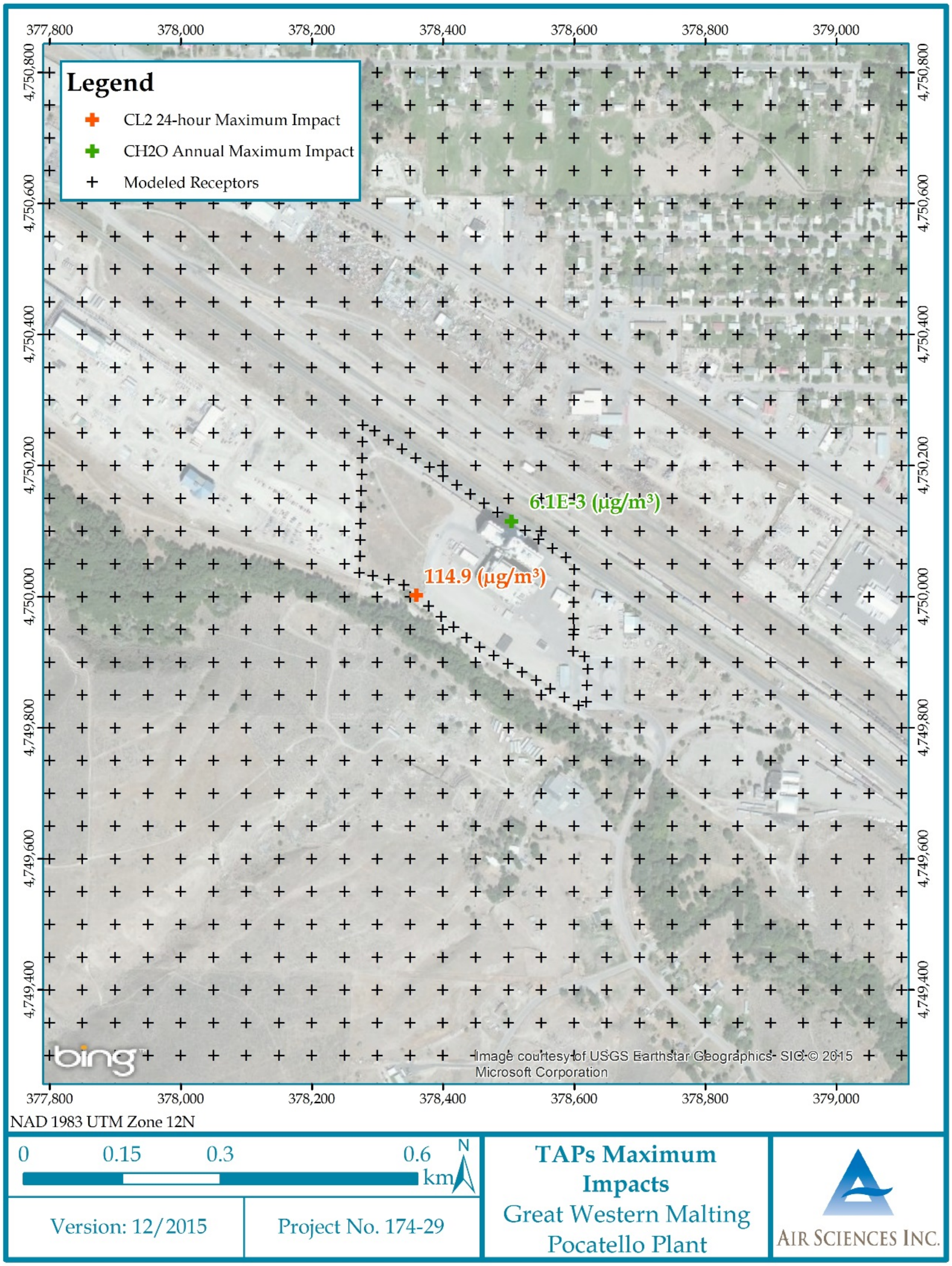
Table 22 and Figure 13 provide results and locations for the TAP impact analyses. With regards to the chlorine impact analysis, a total of four scenarios were modeled due to the operational requirements of the facility. As stated above, germination vessels will be periodically sanitized with hypochlorite, resulting in minor emissions of chlorine. Each of the four germination vessels (each of which contains two exhausts) was modeled separately because GWM will only clean one germination vessel at any given time. The highest of these four scenarios (when Germination Vessel 2 is cleaned) is presented.

Table 22. Results for the TAP Impact Analyses

TAP	Averaging Period	Maximum Modeled Impact ($\mu g/m^3$)[a]	AAC or AACC ($\mu g/m^3$)
Chlorine	24-hour	114.9	150
Formaldehyde	Annual	6.1E-03	7.7E-02

[a.] Microgram/cubic meter.

Figure 13. Map of Locations of TAPs Maximum Modeled Impacts from TAPs Analysis



7.0 Quality Assurance/Control

The modeling inputs for sources, buildings, and receptors were developed from several sources of information such as source diagrams and aerial photos (i.e., Google Earth, other) to determine that their spatial representations were appropriate and accurate. GWM has also utilized third-party software (Lakes View from Lakes Environmental) to review the building/source/receptor configurations in three dimensions for reasonableness compared to other data sources prior to input to AERMOD. Summation of modeled emission rates input to the AERMOD model are summarized in the top headers of the electronic modeling files and this information can be traced back to the emissions information provided in Appendix E. The modeling files and reports have been reviewed by several senior modelers and by the permitting consultant.

8.0 References

CAPCOA. 2011. *Modeling Compliance of The Federal 1-Hour NO_2 NAAQS*. October 27, 2011.

EPA. 1990. *Draft – New Source Review Workshop Manual.* October 1990.

EPA. 2004. *AERMOD: Description of Model Formulation*. EPA-454/R-03-004. September 2004.

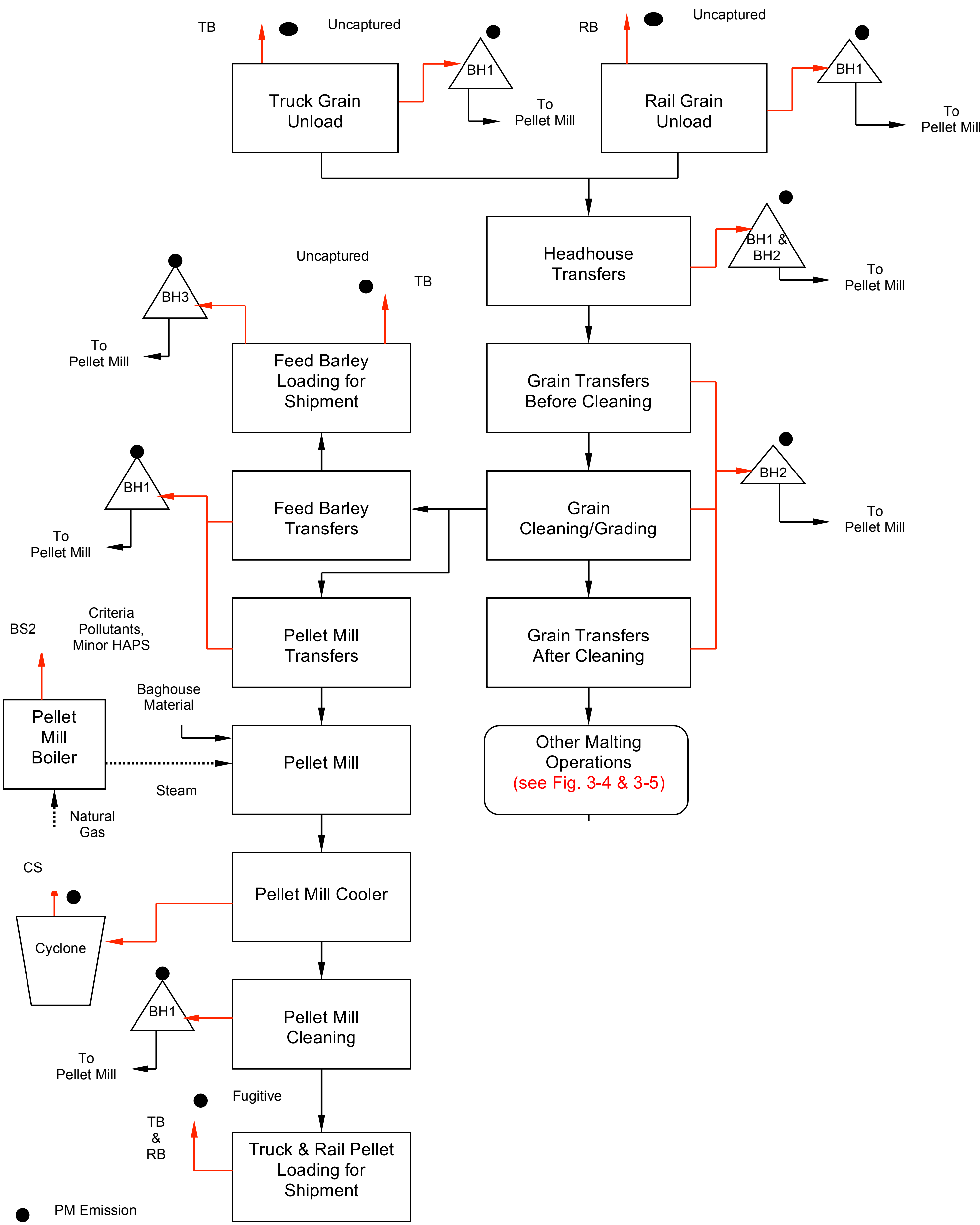
EPA. 2010. *Applicability of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard.* June 28, 2010.

EPA. 2011. *Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-Hour NO_2 National Ambient Air Quality Standard.* March 1, 2011. Accessed October 2, 2015. http://www.epa.gov/region07/air/nsr/nsrmemos/appwno2_2.pdf.

EPA. 2014. *Guidance for $PM_{2.5}$ Permit Modeling*. Memorandum from Stephen D. Page (EPA Director) to Regional Air Division Directors, Regions 1-10. May 20, 2014. Accessed October 2, 2015. http://www.epa.gov/scram001/guidance/guide/Guidance_for_PM25_Permit_Modeling.pdf.

IDEQ. 2013. *State of Idaho Guideline for Performing Air Quality Impact Analyses*. September 2013.

Appendix A – Process Flow Diagrams



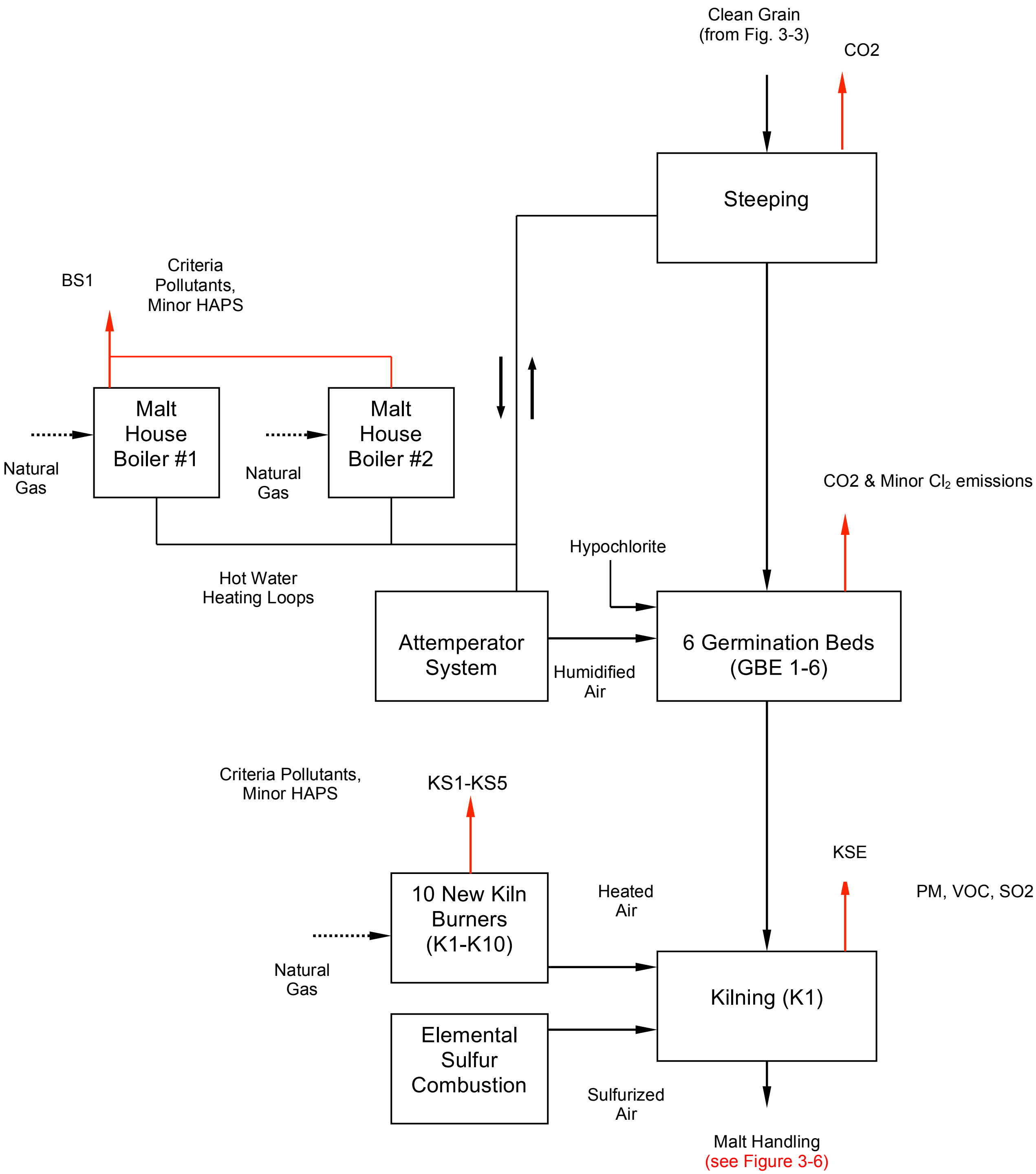
PM Emission

Product or Byproduct Flow

Air Emission Flow

RB = Rail Bay; TB = Truck Bay; BH = Baghouse; CS = Cyclone Stack;
BS = Boiler Stack

Figure 3-2
Grain & By-Product Handling Process Flow



Product Flow Unless Otherwise Noted

Air Emission Flow

Figure 3-3
Existing Malthouse Process Flow

KSE = Kiln Stack Exhaust; BS1 = Boiler Stacks 1
KS1-KS5 = Kiln Burner Stacks 1-5

Preliminary Information- Design Subject to Change

NOTES:
1. FILLING TIME OF 8 STEEPS WITH WATER, MAX 60MIN.
2. DRAIN TIME FOR ALL 8 STEEPS TO BE <30MIN.

Figure 3-4

REV	DESCRIPTION	DRN	CKD	DATE
P2	GENERAL UPDATE BY JIM HALLETT PRIOR TO 2nd DESIGN WORKGROUP WITH JHK	GC	JH	19.06.15

Great Western Malting Co.

SCALE	N.A.		
DRAWN	G. Chatine	DATE	28.04.2015
DESIGNED	JIM HALLETT	DATE	28.04.2015
CHECKED		DATE	
APPROVED		DATE	

PROJECT	POCATELLO MALTINGS EXPANSION
TITLE	PROCESS FLOW DIAGRAM
PROJECT No.	POC001
DRAWING STATUS	DEVELOPMENT
DRAWING No.	00-PFD-001
REVISION	P2

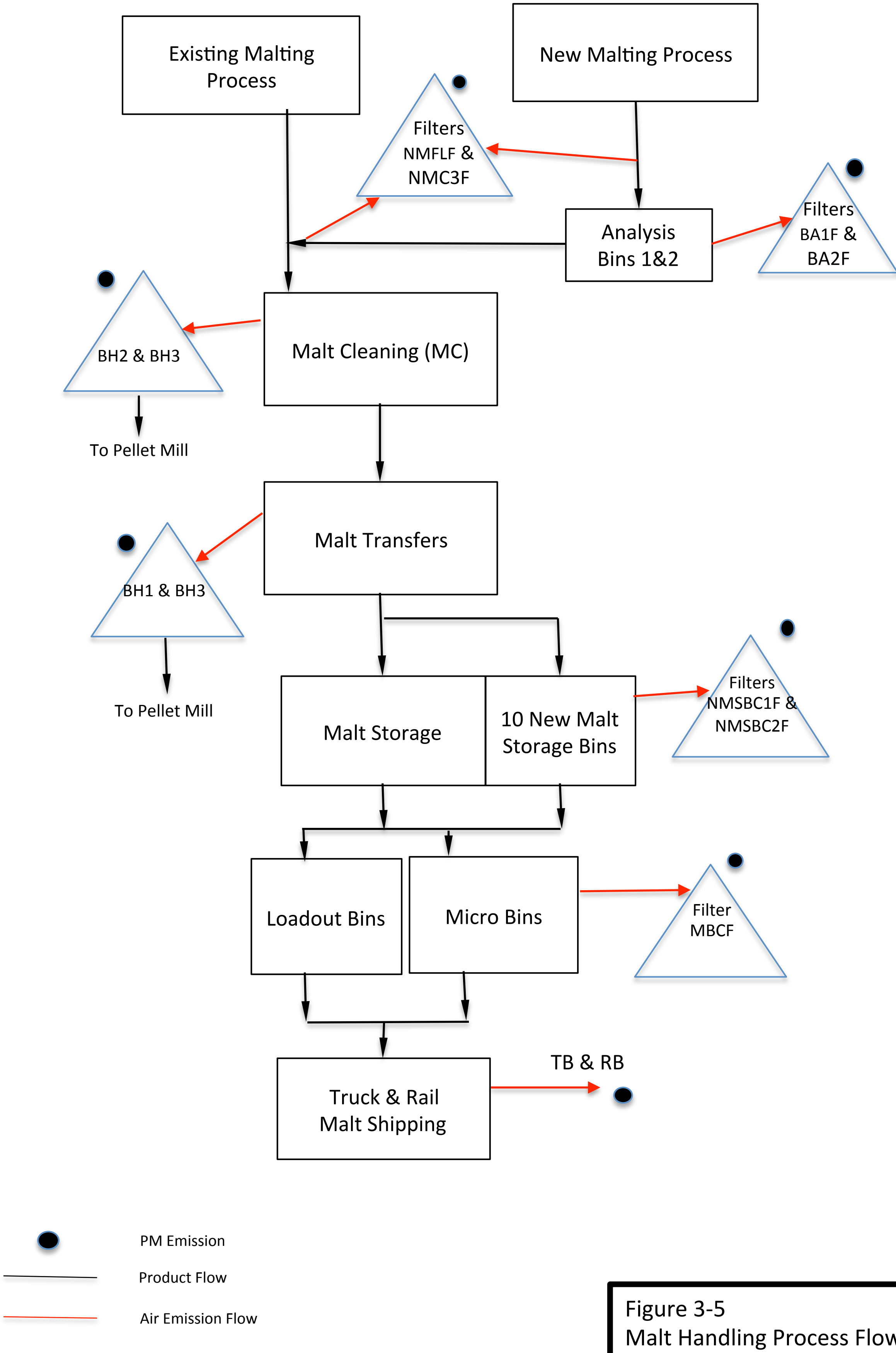


Figure 3-5
Malt Handling Process Flow

Appendix B – DEQ's Conditional Protocol Approval Letter

STATE OF IDAHO
DEPARTMENT OF
ENVIRONMENTAL QUALITY

1410 NORTH HILTON, BOISE, ID 83706 · (208) 373-0502

C. L. "BUTCH" OTTER, GOVERNOR
JOHN TIPPETTS, DIRECTOR

November 5, 2015
Kent Norville
Air Sciences on behalf of Great Western Malting Co.
Pocatello, Idaho

Re: Modeling Protocol for the Great Western Malting Co. facility in Pocatello, Idaho

Dear Kent:

DEQ received your dispersion modeling protocol via email on October 2, 2015 on behalf of the Great Western Malting (GWM) Co. facility in Pocatello, Idaho. The modeling protocol was submitted by Kent Norville of Air Sciences Inc (ASI). After the initial protocol was submitted there was a series of emails between ASI and DEQ regarding proposed modeling methodology. On October 28, 2015, DEQ received an addendum to the protocol. This addendum reflected changes that GWM desired to make in the analyses methodology. The modeling protocol proposes methods and data for use in the ambient impact analyses of a Permit to Construct (PTC) application for an existing facility in order to show compliance for their facility. DEQ has the following comments:

- Comment 1: In the protocol submitted on October 2, 2015, ASI states that the "in-stack NO_2/NO_x ratio" for the natural gas fired boilers in the facility source inventory will be set to 10 percent, and that this value is taken from the San Joaquin Valley Air Pollution Control District (SJVAPCD). DEQ accepts this number as adequate but reminds the applicant that for in stack ratios that do not have adequate documentation and justification, a default value of 0.5 should be used.

- Comment 2: ASI states that the DEQ modeling guidelines have not been updated to reflect the status of the $PM_{2.5}$ NAAQS being equivalent to the 98^{th} percentile 24-modeled concentration versus the maximum 24-hour modeled concentration. DEQ agrees that the NAAQS for 24-hour $PM_{2.5}$ is the 98^{th} percentile 24-modeled concentration.

- Comment 3: Documentation and justification of release parameters must be provided in the application. Refer to Section 3.4.3 of the *State of Idaho Guideline for Performing Air Quality Impact Analyses*, September 2013. Simply stating that values are "manufacturer data" does not constitute adequate documentation and/or justification. DEQ requests that the application describe how the values were obtained (measurement, similar source, combustion evaluation, fan curves, etc.). If values were obtained from an equipment/engineering firm, then those forms, specification sheets, etc. provided by the firm should be included in the application as documentation for the values used in the modeling analyses. The application should be treated as a stand-alone document. If values have been taken from previous permit applications or permits, then the data and derivation from those permit applications or permits must be included in the document. If data was taken from a stack test, then the stack test report and data should also be included in the document

- Comment 4: The protocol discusses modeling emissions from competing sources. ASI made a PRR (public records request) on October 19, 2015 for nearby source information to be used in the modeling analyses. DEQ found the only applicable source to be the Simplot Pocatello facility, and responded with a state inventory data base and previous modeling files for that facility. DEQ and ASI will continue as needed to define the required information needed for the modeling analysis.

- Comment 5: ASI states that operation of the emergency generator will be limited to 100 hours a year, and therefore will not be modeled for the NO_2 1-hour NAAQS analysis, per DEQ modeling guidelines. DEQ reminds ASI that the emissions for the emergency generator still need to be accounted for in the modeling analyses for other pollutants and for annual NO_2 analysis. Unless a permit provision limiting the source to total operations of less than 100 hours/year is requested by the applicant, annual modeling of emergency generators should assume 500 hours/year (a value EPA determined represents PTE, considering both testing, maintenance, and potential use during emergencies

- Comment 6: Descriptions of the facility process are generally adequate. The ambient air boundary, as stated in the State of Idaho Guideline for Performing Air Quality Impact Analyses, should be defined by an area where the public access is precluded. This includes separation from areas of habitation or activities by people not employed by the facility. If a physical barrier is not used to preclude public access from areas excluded from ambient air, then the application must thoroughly describe the methods used to practically preclude access.

- Comment 7: ASI has proposed to use the meteorological data provided by DEQ. This data was collected at the nearby Pocatello airport for the period 2008-20012, and is deemed to be appropriately representative of the facility locale.

- Comment 8: Air Sciences has proposed to use hourly ozone data from Crater of the Moons NP for modeling NO_2 impacts at the Great Western Malt facility in Pocatello, Idaho. DEQ approves this request, and has the following comments: The ozone data collected at the Craters monitoring site should be conservative for application to Pocatello because Craters has no local ozone scavenging from NO_x local point sources or traffic sources, and therefore will have higher ozone values during morning and evening times(higher traffic volume periods) than data collected in a more urban setting. The site is situated at an elevation about 2000 feet above the facility location, and therefore will also be conservative in nature, as ozone typically increases slightly with elevation. It should be noted that Craters of the Moon is situated in a different airshed from the Pocatello vicinity, and is characterized by its location near higher terrain to the north. Pocatello is characterized by the valley flow along the Snake River corridor flowing throughout southern Idaho. A case study performed by DEQ [1] in 2012 compared monitored ozone data collected at Craters and several locations in Idaho. The locations closest to Pocatello are Paul and Idaho Falls. In summary, the ozone data collected at Craters was found typically to be slightly higher than the data collected at both of those sights. The data from Craters appears to reflect the overall regional data in the area well, and has adequate correlation with the data monitored at Paul and Idaho Falls. While the hourly concentrations may not match exactly between the sites, it appears that the ozone concentrations at Craters is conservative in nature with respect to an area such as Pocatello , and therefore in most hourly cases would be acceptable in a modeling assessment of NO_2 impacts.

- Comment 9: GWM discusses increased emissions and modeling parameters for characterization of fugitive sources such as road traffic. Fugitive emissions from vehicle traffic on roads and wind erosion from storage piles are normally not included in the modeling for minor source applications. DEQ may require modeling of these sources if a potential exceedance of air quality standards is evident.

- Comment 10: DEQ has recently developed a modeling report template form for consultants/applicants to use when submitting modeling analyses. An electronic copy of this template should have been attached to the email delivering this protocol approval notice. DEQ now **requires** that this template be used for the submitted modeling analyses.

DEQ modeling staff considers the submitted dispersion modeling protocol, with consideration and resolution of the additional items noted above, to be approved. It should be noted, however, that the approval of this modeling protocol is not meant to imply approval of a completed dispersion modeling analysis. Please refer to the *State of Idaho Air Quality Modeling Guideline*, which is available on the Internet at http://www.deq.state.id.us/air/permits_forms/permitting/modeling_guideline.pdf, for further guidance.

DEQ modeling staff requests submission of electronic copies of all modeling input and output files (including BPIP and AERMAP input and output files) with an analysis report. Also, please include with the application materials a copy of the protocol and this protocol approval in the appendix of the application. If you have any questions, please call at 208 373 0220

Sincerely,

Thomas Swain
Analyst 3 , Air Modeling
Idaho Department of Environmental Quality
208 373-0220
thomas.swain@deq.idaho.gov

[1] *Comparison of Ozone level;s at Craters of the Moon to Temporary Portable Monitor Locations, DEQ 2012*

Appendix C – Original Modeling Protocol

AIR SCIENCES INC.

DENVER • PORTLAND • LOS ANGELES

Air Quality Modeling Protocol: Great Western Malting Facility in Pocatello, Idaho

PREPARED FOR:
GREAT WESTERN MALTING CO.

PROJECT NO. 174-29-1
OCTOBER 2015

TABLE OF CONTENTS

Tables

Figures

Appendices

1.0 INTRODUCTION AND PURPOSE

1.1 Facility Description and Location

Great Western Malting Co. (GWM) produces high-quality malted barley that is a basic ingredient in beer. GWM is planning to increase the malting capacity of its malting facility located in Pocatello, Idaho. Figure 1 shows the location of the GWM facility and surrounding vicinity. The existing malt house is located at 42° 53′ 35.6″ N and 112° 29′ 17.2″ W.

The Universal Transverse Mercator (UTM) coordinate system projected in North American Datum of 1983 (NAD83), Zone 12, will be used in the air quality modeling analysis to define all locations in the modeling domain (sources, buildings, and receptors).

1.2 Project Overview

In general, the main proposed change at the malting facility will be to increase annual barley production throughput. The expansion project will add new malting equipment to the facility, including new germination vessels, new steeps, and a new kiln. The existing malting equipment will remain unchanged. The increase in malt production will require additional storage and cleaning equipment at the existing facility. No changes to the barley handling equipment at the existing facility are planned, as this handling equipment is sized to handle the additional barley needed for the new malting equipment. However, there will be a few new barley transfer points added to the facility as barley is conveyed to the new malting equipment.

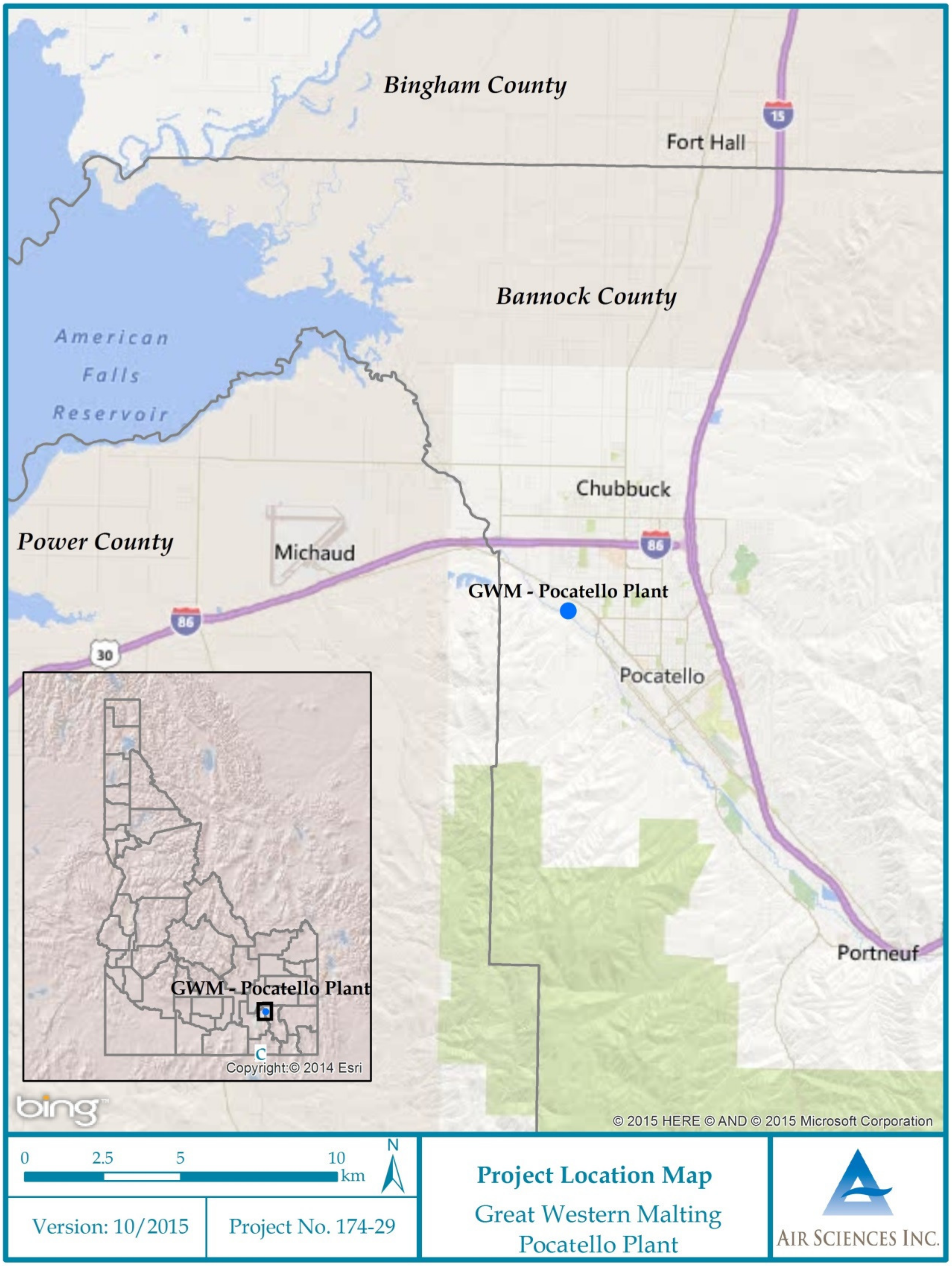
1.3 Goals of the Air Quality Analysis

The air quality analysis described in this modeling protocol is intended to demonstrate that emissions from the proposed project will not result in criteria pollutant impacts that exceed state or federal ambient air quality standards, and that toxic pollutant impacts will not exceed Idaho's toxic air pollutant (TAP) increments.

1.4 Applicable Regulations and Requirements

From an air quality perspective, the existing facility is a minor source of air pollution and currently operates under a Tier II operating permit. The GWM facility is located in an attainment area for all criteria air pollutants; that, existing air pollutant levels are less than the National Ambient Air Quality Standards (NAAQS). The proposed facility expansion will be a minor modification because the emissions associated with the modification will be less than significant emission rates (e.g., 100 tpy CO, 40 tpy NO_X, 40 tpy SO_2, 15 tpy PM_{10}, 10 tpy $PM_{2.5}$, etc.).

Figure 1. Project Location Map



1.5 Pollutants of Concern

Criteria Pollutants - Following Idaho Department of Environmental Quality's (DEQ) modeling guidelines (IDEQ 2013), modeling needs to be conducted when the facility's or project's pollutant emissions exceed modeling thresholds. The preliminary facility criteria pollutant emission increases associated with the proposed modification and associated modeling thresholds are shown in Table 1. Based on GWM's review of emissions from new project sources, GWM asserts that only CO, NO_X, PM_{10}, and $PM_{2.5}$ need to be modeled. The SO_2 emissions increase from the project does not exceed modeling thresholds and modeling is not required. Project emissions of lead are insignificant. The NAAQS for the criteria pollutants to be modeled are provided in Section 4.2.

Table 1. Estimated GWM Criteria Pollutant Emissions and Modeling Thresholds

Pollutant	Type	Estimated Emissions from New Project Sources	Units	DEQ Level 1 Modeling Threshold *	Units	Modeling Required?
CO	Short-Term	17.5	lb/hr	15	lb/hr	Yes
NO_X	Short-Term	5.2	lb/hr	0.20	lb/hr	Yes
	Long-Term	10.8	ton/yr	1.2	ton/yr	Yes
SO_2	Short-Term	0.06	lb/hr	0.21	lb/hr	No
	Long-Term	0.16	ton/yr	1.2	ton/yr	No
PM_{10}	Short-Term	2.84	lb/hr	0.22	lb/hr	Yes
$PM_{2.5}$	Short-Term	1.95	lb/hr	0.054	lb/hr	Yes
	Long-Term	6.41	ton/yr	0.35	ton/yr	Yes

* DEQ's Level 1 thresholds in Table 2 of the modeling guidelines.

Toxics - Idaho Air Rules Section 161 states, "Any contaminant which is by its nature toxic to human or animal life or vegetation shall not be emitted in such quantities or concentrations as to alone, or in combination with other contaminants, injure or unreasonably affect human or animal life or vegetation." DEQ may require toxics analyses as a case-by-case basis. Per GWM's discussion with DEQ, chlorine impacts from the facility will be evaluated in the dispersion modeling analysis. GWM sanitizes its existing germination equipment, and will sanitize its new germination vessels with sodium hypochlorite, which may produce minor amounts of chlorine emissions.

Applicable TAPs increments (called Acceptable Ambient Concentrations [AACs]) are listed in Idaho Air Rules Section 585 for non-carcinogens. Chlorine is listed in Section 585 for non-carcinogens and the AAC for chlorine is 0.15 mg/m^3, on a 24-hour average basis. For GWM's dispersion modeling analysis, the highest-first-highest (H1H) 24-hour average modeled concentrations will be compared to the AAC for chlorine.

For carcinogens, applicable TAPs increments (called Acceptable Ambient Concentrations for Carcinogens [AACCs]) are listed in Idaho Air Rules Section 586. A preliminary analysis of GWM's toxics emissions indicates that modeling is also necessary for formaldehyde. Table 2 provides the preliminary facility toxic pollutant emissions (from new project sources) and modeling thresholds for pollutants anticipated to be included in the TAPs modeling analysis.

Table 2. Estimated GWM Toxic Pollutant Emissions and Modeling Thresholds

Pollutant	Type	Averaging Period	Project Estimated Emissions (lb/hr)	Threshold (lb/hr)	Modeling Required?
Chlorine	Non-carcinogen	24-hour	6.45	0.2	Yes
Formaldehyde	Carcinogen	Annual	1.4E-03	5.1E-04	Yes

2.0 EMISSIONS AND SOURCE DATA

2.1 Description of Facility Processes and Emissions Controls

It is anticipated that the entire facility may need to be modeled for this analysis. Thus, both new and existing sources will need to be considered. Complete process flow diagrams for the existing and proposed expansion operations are provided in Appendix A.

2.1.1 Existing Facility Process

Barley is received by truck or railcar and unloading operations occur at the Truck Bay (TB) and Rail Bay (RB). During unloading, the trucks or railcars discharge barley into hoppers, from which the barley is conveyed through the headhouse. Unloading operations result in the generation of particulate matter (PM) emissions. The truck bay receiving pit is equipped with side draw vacuums with exhaust to baghouse #1 (BH1). Hopper-type trucks account for a majority of the truck receiving operations. These trucks and the railcar unloading operations employ choke feed to the receiving pit to minimize fugitive PM emissions.

The barley is transferred through the headhouse to the barley storage silos. PM emissions generated by headhouse transfer operations are controlled by BH1. Material collected by all the centralized baghouse systems (BH1, BH2, and BH3) is sent to a pellet mill. The barley is then cleaned and graded with transfers and the cleaning device controlled by BH2. "Thin" barley is transferred to Feed Barley transfer bins, and this material is trucked offsite and used as animal feed. Feed Barley transfer operations are controlled by BH1. Feed Barley truck loadout operations are controlled by a cyclone side vacuum draw system that exhausts to BH3.

After cleaning, the barley is transferred to the malthouse, where it is steeped by placing it in large tanks with cool, oxygen-enriched water. Following steeping, the barley is dropped to one of six temperature- and humidity-controlled germination beds and allowed to grow. The steeping and germination processes also are served by chilled water systems. The six germination beds are periodically sanitized with hypochlorite, resulting in minor emissions of chlorine through the Germination Bed Exhaust emission points (GBE 1&4, GBE 2&5, and GBE 3&6). The steeping and germination process requires heated air provided by two natural-gas-fired hot water boilers that exhaust combustion byproducts to a common stack (BS1).

Following steeping and germination, "green" malt is dried in an indirect natural-gas-fired malt kiln. The malt kiln has two levels. Clean malt enters the upper deck of the kiln and is dried. The barley is then transferred to the lower deck of the kiln, where it is further dried to about 4 percent moisture content. During a portion of the kilning, sulfur may be burned in a sulfur stove and exhausted to the kiln primarily as sulfur dioxide (SO_2). The SO_2 serves as a fungicide, bactericide, and preservative. The kiln emits PM, volatile organic compounds (VOC), and SO_2.

These emissions are vented through one stack designated as KSE. The malt kiln burner stacks (KS1-KS5) are located within the main kiln stack.

The malted barley is then cleaned and transferred to the malt storage silos until it is shipped. PM generated during the cleaning is collected in the BH2 baghouse, and transfers are collected in the BH3 baghouse.

Cleaning byproducts and material collected by the baghouses are sent to a pellet mill, where the material is pelletized and shipped offsite. Loadout of pelletized material occurs via truck and results in fugitive PM emissions. The pellet mill mixer requires steam provided by a steam boiler that discharges combustion byproducts through BS2.

The malt is shipped by railcar or truck. PM is generated during loading. These emissions occur at the RB and TB emission points.

Fugitive road dust is generated by truck deliveries to, and shipments from, the plant. The trucks travel approximately 1,550 feet on the paved access roads. SWEKO trucks that remove some waste material from the facility travel approximately 600 feet on a paved road.

2.1.2 New Facility Process

The expansion project will add new malting equipment to the facility, thus increasing production throughput to a total of about 324,000 MT barley/year. No changes to the barley handling equipment at the existing plant are planned as the equipment is already sized to handle the additional barley needed.

The new malting equipment will include 16 new steeps, 4 new germination vessels, and 1 new kiln. The kiln will use 4 air-to-air heat exchangers to provide the drying air. The burners for the heat exchangers will be natural-gas-fired, each at 18.15 MM Btu/hr heat input capacity. Each burner will have its own exhaust stack. Air from the kiln will be discharged from a single stack.

Each steep will have its own exhaust stack and each germination vessel will have two exhaust stacks. Just like in the existing germination equipment, the new germination vessels will be sanitized using sodium hypochlorite, which may produce minor amounts of chlorine emissions.

The hot water for germination will be provided by 6 new natural-gas-fired boilers. Each boiler will have a 2 MM Btu/hr heat input capacity.

After the malt is dried in the kiln, it will be cleaned and placed into storage. The stored malt will be cleaned again before it is loaded into trucks or railcars and shipped offsite. The increase in malt production will require the addition of storage and cleaning equipment to the existing plant. There will be a couple of new barley transfer points as barley is conveyed to the new malting equipment. New dust collector(s) will be added to capture PM from the barley transfers. The plan is to:

- Add 8 new 750 MT malt storage silos.
- Replace some existing kiln malt cleaning equipment with new equipment (scalper and aspirator). The existing baghouses have enough capacity and will be used to control dust.
- Add 2 new malt analysis bins with filters.
- Add 4 new 40 MT truck loadout bins and chutes.
- Add a cyclone for conveying byproducts to the byproduct bin. A dust collector will be used to control emissions from the cyclone exhaust.
- Add new conveyors and transfers as needed to move the malt and other materials. Dust from these activities will be controlled using the existing baghouses or by the addition of new dust collectors.

The pellet mill has enough capacity to handle the barley residue, malt byproducts, and baghouse material from the expansion so no changes are planned to the pellet mill system or pellet boiler.

There will be an increase in the number of trucks delivering barley and supplies to and shipping malt and other materials from the facility. As a result, there will be an increase in fugitive dust from the paved onsite roads.

2.2 Emission Points

Table 3 shows the existing and proposed emission points and their modeling ID for the modeling analysis. Table 4 shows the emissions for each source. Table 5 shows a comparison of facility-wide PTE emissions pre- and post-project. The locations of the sources are shown in Figure 2. Note that the emissions and source parameter information provided in this protocol are preliminary and subject to change prior to submittal of the permit application.

Table 3. GWM Emission Sources and Modeling Identification

Model ID	Description	New or Existing
STC1F	Spot Filter - Barley to Steeps	New
STC2F	Spot Filter - Above Steeps	New
GV1-4	Germination Vessels	New
KB1	Kiln Air Heater 1 Burner Stack	New
KB2	Kiln Air Heater 2 Burner Stack	New
KB3	Kiln Air Heater 3 Burner Stack	New
KB4	Kiln Air Heater 4 Burner Stack	New
K2	Kiln 2 Exhaust	New
NMLF	Spot Filter - Analysis Bins Elevator	New
BA1F	Spot Filter - Analysis Bin W	New
BA2F	Spot Filter - Analysis Bin E	New
KBPCF	Spot Filter - Byproduct Cyclone	New
NMC3F	Spot Filter - Kiln Tunnel	New
MBCF	Spot Filter - Micro Bin	New
GVB1	Germination Vessel Boiler 1	New
GVB2	Germination Vessel Boiler 2	New
GVB3	Germination Vessel Boiler 3	New
GVB4	Germination Vessel Boiler 4	New
GVB5	Germination Vessel Boiler 5	New
GVB6	Germination Vessel Boiler 6	New
MAU1	Make Up Air Unit 1	New
MAU2	Make Up Air Unit 2	New
NMSBC1F	New Malt Storage Bins 1-5 Conveyor 1 Filter	New
NMSBC2F	New Malt Storage Bins 6-10 Conveyor 2 Filter	New
EG1	Emergency Generator	Existing
GBE1-6	Germination Beds	Existing
BH1	Baghouse - Barley Head House	Existing
BH2	Baghouse - Malt & Barley Cleaning	Existing
BH3	Baghouse - Malt Cleaning, Loading & Transfer	Existing
BS1	Malt House Boilers Stack	Existing
BS2	Pellet Mill Boiler Stack	Existing
CS	Pellet Mill Cooler Stack	Existing
RB1	Rail Bay	Existing
RB2	Rail Bay	Existing
TB	Truck Bay	Existing
KSE/KS1-5	Kiln 1	Existing

Table 4. GWM Emission Rates for Existing and Proposed Sources

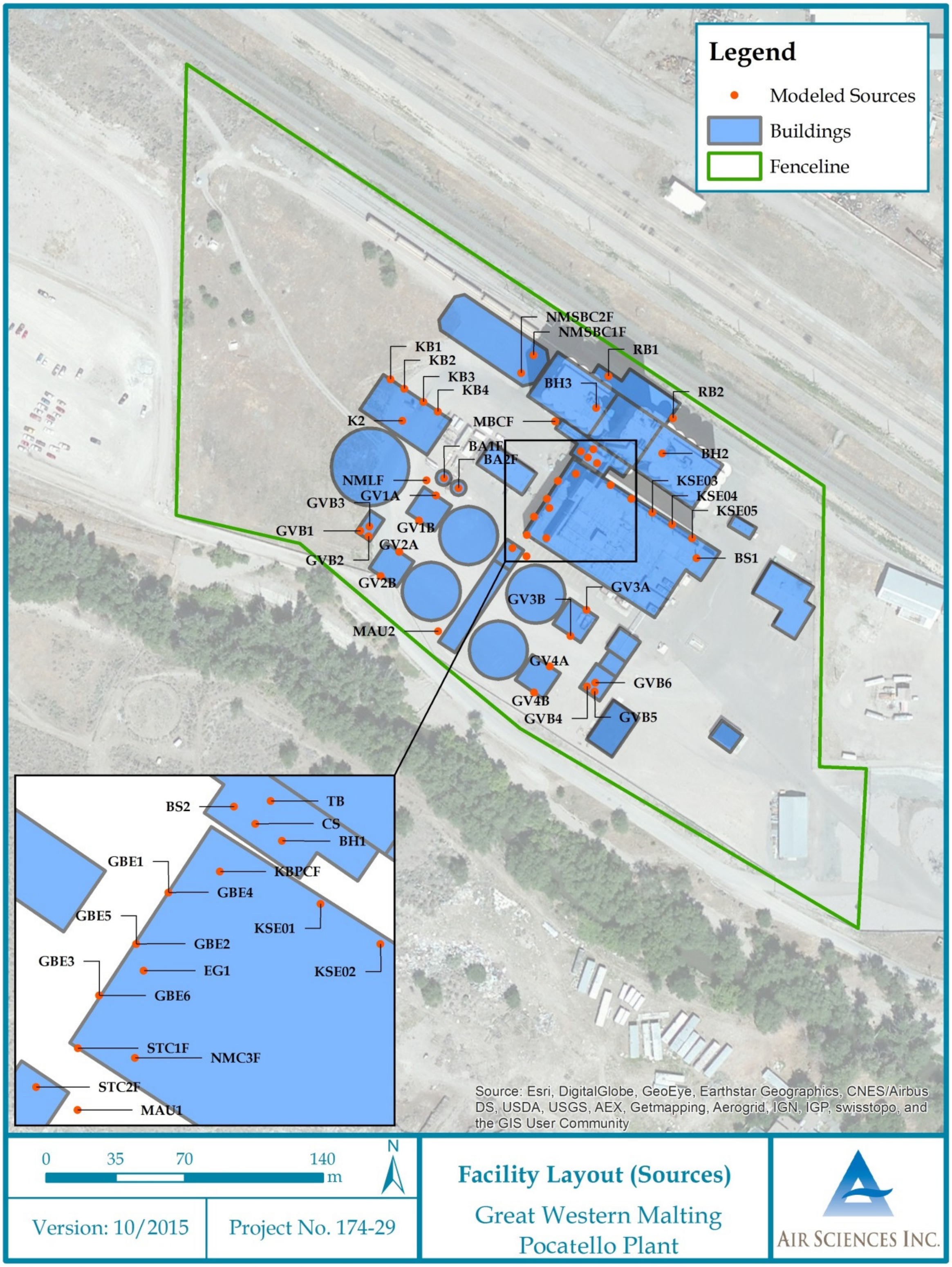
Model ID	CO (lb/hr)	NO_X (lb/hr)	NO_X (lb/yr)	$PM_{2.5}$ (lb/day)	$PM_{2.5}$ (lb/yr)	PM_{10} (lb/day)	SO_2 (lb/hr)	CL_2[1] (lb/day)	CH_2O[1] (lb/hr)	New or Existing
STC1F				0.12	5.7	0.72				New
STC2F				0.12	5.7	0.72				New
GV1-4								12.9[2]		New
KB1	4.0	0.65	3,885.0	3.2	798.0	3.2	0.011		0.00030	New
KB2	4.0	0.65	3,885.0	3.2	798.0	3.2	0.011		0.00030	New
KB3	4.0	0.65	3,885.0	3.2	798.0	3.2	0.011		0.00030	New
KB4	4.0	0.65	3,885.0	3.2	798.0	3.2	0.011		0.00030	New
K2				27.2	8,734.4	43.0				New
NMLF				0.17	5.2	0.98				New
BA1F				0.17	2.6	0.98				New
BA2F				0.17	2.6	0.98				New
KBPCF				0.16	20.1	0.16				New
NMC3F				0.12	5.2	0.72				New
MBCF				0.034	0.48	0.20				New
GVB1	0.17	0.06	525.6	0.36	133.2	0.36	0.0012		0.000034	New
GVB2	0.17	0.06	525.6	0.36	133.2	0.36	0.0012		0.000034	New
GVB3										New
GVB4	0.17	0.06	525.6	0.36	133.2	0.36	0.0012		0.000034	New
GVB5	0.17	0.06	525.6	0.36	133.2	0.36	0.0012		0.000034	New
GVB6										New
MAU1	0.18	0.22	1,916.7	0.40	145.7	0.40	0.0013		0.000037	New
MAU2	0.18	0.22	1,916.7	0.40	145.7	0.40	0.0013		0.000037	New
NMSBC1F				0.12	4.7	0.72				New
NMSBC2F				0.12	4.7	0.72				New
EG1	0.40	1.9	186.0	3.2	13.2	3.2	0.0123			Existing
GBE1-6								-		Existing
BH1				0.30	22.6	1.8				Existing
BH2				0.28	27.5	3.6				Existing
BH3				0.34	8.3	2.4				Existing
BS1	0.53	0.63	2,103.6	1.1	159.9	1.1	0.0038		-	Existing
BS2	0.21	0.25	2,190.0	0.46	166.44	0.46	0.0015		-	Existing
CS				8.7	1,960.2	8.7				Existing
RB1				2.1	132.6	12.1				Existing
RB2				2.1	132.6	12.1				Existing
TB				5.7	183.8	33.3				Existing
KSE/KS1-5	3.1	4.5	29,000.0	21.7	7,009.1	34.2	14.9		-	Existing

[1]The TAP emissions listed are from new emission units in accordance with the Idaho Air Rules Section 203.03. Sources that show a dash (-) for these pollutants denote emissions not associated with the facility expansion.
[2] These sources will be modeled operating two hours per day and their emissions will be divided among two release points at any given time.

Table 5. GWM Emission Rates for Pre- and Post-Project

Hourly Emissions	PM_{10} lb/hr	$PM_{2.5}$ lb/hr	SO_2 lb/hr	NO_X lb/hr	CO lb/hr
Pre-Project Potential to Emit (PTE) Minus Fugitive Emissions	4.37	1.99	14.99	12.15	10.21
Post-Project PTE Minus Fugitive Emissions	6.92	3.65	15.01	10.58	21.38
Changes in PTE	2.55	1.66	0.02	-1.57	11.17
Annual Emissions	**PM_{10}** ton/yr	**$PM_{2.5}$** ton/yr	**SO_2** ton/yr	**NO_X** ton/yr	**CO** ton/yr
Pre-Project PTE Minus Fugitive Emissions	7.32	4.02	20.53	14.55	17.33
Post Project PTE Minus Fugitive Emissions	16.88	11.25	20.68	27.48	66.23
Changes in PTE	9.56	7.23	0.15	12.93	48.90

Figure 2. Facility Layout Map (Sources)



2.3 Source Parameters

The new and existing sources are characterized in Table 6 and Table 7, respectively. For new sources, release characteristics are determined by engineering design and vendor specifications. These parameters are preliminary and subject to change prior to the submittal of the permit application for the project.

New Source Characterizations

The spot filters for the transfer of barley to the steeps and above the steeps (STC1F and STC2F, respectively) are located on the steep house and the existing malt house, respectively. Each spot filter stack will be modeled as a POINT source with vertical release at ambient temperature. The kiln air heater burner stacks (KB1-KB4) as well as the kiln 2 exhaust (K2) stack are located within the kiln plenum building and will be modeled as POINT sources. Each of these sources is a vertical stack that releases on the roof of the building. Six spot filters (NMLF, BA1F, BA2F, KBPCF, NMC3F, MBCF) located throughout the facility will be modeled as POINT sources. The release points on each of the spot filters have vertical releases at ambient temperature.

The germination vessel boiler stacks (GBV1-GBV6), located on either side of the germination plenums, will be modeled as POINT sources with vertical releases. The make up air units (MAU1 and MAU2), located near the steep house, will be modeled as POINT sources with vertical releases at ambient temperature. The new malt storage bin conveyor filters (NMSBC1F and NMSBC2F), located at the malt storage bins, will be modeled as POINT sources with vertical release orientations. The onsite emergency generator will be modeled as a POINT source with a vertical release.

The four germination plenums (GV1A, GV1B, GV2A, GV2B, GV3A, GV3B, GV4A, and GV4B) will exhaust horizontally on two sides of each plenum. Each emission point will be modeled as a VOLUME source following the AERMOD guideline. The initial sigma y will be set to the length of each plenum divided by 4.3, and the initial sigma z will be equal to each plenum height divided by 2.15.

Table 6. GWM New Source Characterizations

Model ID	UTM E (m)	UTM N (m)	Elevation (m)	Source Parameters (Varies by Source Type)			
New POINT Sources				**Height (m)**	**Temp.[1] (K)**	**Velocity (m/s)**	**Diameter (m)**
STC1F	378,450	4,750,027	1,350	57.9	0.0	2.7	0.3
STC2F	378,443	4,750,020	1,350	56.1	0.0	2.7	0.3
KB1	378,381	4,750,105	1,350	21.3	327.6	3.8	0.6
KB2	378,388	4,750,101	1,350	21.3	327.6	3.8	0.6
KB3	378,398	4,750,094	1,350	21.3	327.6	3.8	0.6
KB4	378,405	4,750,089	1,350	21.3	327.6	3.8	0.6
K2	378,387	4,750,084	1,350	20.4	310.9	0.1	13.9
NMLF	378,400	4,750,054	1,350	1.8	0.0	14.0	0.3
BA1F	378,408	4,750,056	1,350	24.4	0.0	3.6	0.3
BA2F	378,416	4,750,050	1,350	24.4	0.0	3.6	0.3
KBPCF	378,475	4,750,058	1,350	22.9	0.0	3.6	0.3
NMC3F	378,460	4,750,025	1,350	2.7	0.0	2.7	0.3
MBCF	378,465	4,750,084	1,350	15.2	0.0	0.9	0.3
GVB1	378,366	4,750,029	1,350	6.1	366.5	9.2	0.2
GVB2	378,370	4,750,026	1,350	6.1	366.5	9.2	0.2
GVB3	378,371	4,750,031	1,350	6.1	366.5	9.2	0.2
GVB4	378,481	4,749,950	1,350	6.1	366.5	9.2	0.2
GVB5	378,485	4,749,947	1,350	6.1	366.5	9.2	0.2
GVB6	378,485	4,749,952	1,350	6.1	366.5	9.2	0.2
MAU1	378,450	4,750,016	1,350	1.8	366.5	4.7	0.2
MAU2	378,405	4,749,978	1,350	1.8	366.5	4.7	0.2
NMSBC1F	378,454	4,750,118	1,350	27.4	0.0	2.7	0.3
NMSBC2F	378,447	4,750,109	1,350	27.4	0.0	2.7	0.3
EG1	378,462	4,750,040	1,350	1.8	588.7	56.2	0.1
New VOLUME Sources				**Rel. Ht. (m)**	**σ_y (m)**	**σ_z (m)**	**-**
GV1A	378,404	4,750,047	1,350	6.1	3.6	4.1	-
GV1B	378,396	4,750,034	1,350	6.1	3.6	4.1	-
GV2A	378,386	4,750,018	1,350	6.1	3.6	4.1	-
GV2B	378,376	4,750,006	1,350	6.1	3.6	4.1	-
GV3A	378,481	4,749,989	1,350	6.1	3.6	4.1	-
GV3B	378,472	4,749,976	1,350	6.1	3.6	4.1	-
GV4A	378,462	4,749,960	1,350	6.1	3.6	4.1	-
GV4B	378,454	4,749,947	1,350	6.1	3.6	4.1	-

[1]0.0 K represents ambient release temperature.

Existing Source Characterizations

The three baghouses (BH1, BH2, and BH3) exhaust at a 45-degree angle downward toward the roof. Around two of the silo baghouses (BH2 and BH3), there is a three-sided, five-foot-high sound wall that blocks the flow. These three sources will be modeled as POINT sources with horizontal exhausts with a height set to the roof height (not actual stack height).

The main malt kiln stack (KSE) is a long roof vent, which exhausts vertically. The malt kiln burner stacks (KS1-KS5) are located within the main kiln stack. Thus, these sources will be merged. For this merged source, a merged stack approach similar to what was utilized for modeling the GWM facility in 2005 will be used. In the previous modeling approach for this source, the total malt kiln exhaust was modeled as five point sources, each with one-fifth of the exhaust area, volumetric flow rate, and emissions. This assumption was conservative since the plume merging effects were ignored. Emissions and source parameters from this source will be derived from a previous source test.

The truck bay will be modeled as a VOLUME source with initial dispersion coefficients set according to the AERMOD guideline; that is, the initial sigma y will be set to the length of the silo divided by 4.3, and the initial sigma z equal to the silos height divided by 2.15. This assumption is conservative for the truck bay since silos are between the source and the property line.

The rail bay is located on the property line side of the silos within an enclosed structure, with exposure to ambient air through the rail car entries. Thus, this source will be split into two VOLUME sources, one on each side of the rail bay. The parameters of the VOLUME source will be set according to the AERMOD guideline based on the size of the rail bay, and not the silos. Thus, the initial sigma y will be set to the width of the silo divided by 4.3, and the initial sigma z equal to the rail bay height divided by 2.15.

Table 7. GWM Existing Source Characterizations

Model ID	UTM E (m)	UTM N (m)	Elevation (m)	Source Parameters (Varies by Source Type)			
Existing POINT Sources				Height (m)	Temp.[1] (K)	Velocity (m/s)	Diameter (m)
BS1	378,536	4,750,015	1,350	34.1	449.8	5.4	0.9
CS	378,481	4,750,066	1,350	29.4	310.9	7.1	0.7
KSE01[2]	378,493	4,750,052	1,350	31.7	299.3	1.9	6.3
KSE02[2]	378,503	4,750,045	1,350	31.7	299.3	1.9	6.3
KSE03[2]	378,514	4,750,038	1,350	31.7	299.3	1.9	6.3
KSE04[2]	378,524	4,750,032	1,350	31.7	299.3	1.9	6.3
KSE05[2]	378,534	4,750,025	1,350	31.7	299.3	1.9	6.3
BH1	378,486	4,750,063	1,350	7.3	0.0	20.8	1.0
BH2	378,519	4,750,068	1,350	34.4	0.0	27.4	1.0
BH3	378,485	4,750,091	1,350	34.4	0.0	29.7	1.0
BS2	378,478	4,750,069	1,350	10.4	477.6	65.9	0.3
Existing VOLUME Sources				Rel. Ht. (m)	σ_y (m)	σ_z (m)	-
RB1	378,492	4,750,107	1,350	17.2	11.8	16.0	-
RB2	378,524	4,750,086	1,350	17.2	11.8	16.0	-
TB	378,484	4,750,070	1,350	17.2	11.8	16.0	-

[1]0.0 K represents ambient release temperature.
[2]The Kiln 1 sources were merged together and five equivalent stacks (KSE01-05) will be modeled, consistent with the approach utilized from the previous 2005 modeling of the facility.

Treatment of Intermittent Emissions for 1-Hour Analyses

This section discusses the treatment of intermittent emissions for 1-hour analyses.

In its guidance on NO_2 1-hour modeling (EPA 2011), EPA has recognized that intermittent sources that do not operate continuously or frequently enough, specifically emergency generators, are less likely to contribute significantly to the annual distribution of daily maximum 1-hour values. EPA recommends "*that compliance demonstrations for the 1-hour NO_2 NAAQS be based on emission scenarios that can logically be assumed to be relatively continuous or which occur frequently enough to contribute significantly to the annual distribution of daily maximum 1-hour concentrations*" (EPA 2011).

Also from the DEQ modeling guidelines (IDEQ 2013), "*emissions sources that operate intermittently may be excluded from the SIL analysis and/or cumulative NAAQS analysis, approved by DEQ on a case-by-case basis, to the extent that it can be reasonably concluded that such sources* *could not measurably affect the compliance determination. If the intermittent sources are engines powering emergency generators or fire suppression water pumps, and operations are less than 100 hours/year for operational testing and maintenance, the sources can be excluded from compliance demonstrations for the 1-hour NO_2 NAAQS, unless specifically required at the discretion of the DEQ Director."*

There is an emergency generator at GWM that will supply power to critical networks and equipment in the event that normal power supply is interrupted. The PTE for this generator is determined using the 100 hours per year; however, it is expected to operate for even fewer hours and on a random schedule. Thus, the operation of the generator is not frequent enough to significantly contribute to the annual distribution of daily maximum 1-hour concentrations. As such, emissions from the emergency generator will not be included in the NO_2 1-hour analyses.

3.0 AIR QUALITY MODELING METHODOLOGY

This section presents the air quality analysis methodology, data sets, and modeling techniques to be used to estimate the worst-case changes in ambient air quality levels that could result from the GWM facility.

3.1 Model Selection

Air dispersion models are a collection of mathematical algorithms packaged into a computer program to simulate the atmospheric dispersion of an air pollutant. Air dispersion models typically require source data (emissions, location, physical characteristics, etc.) and meteorological data (wind speed and direction, temperature, mixing height, etc.) to predict pollutant concentrations at downwind receptor locations, as a result of a source's emissions. These air dispersion models are widely used to assess changes in the ambient air resulting from a project's air emissions and to demonstrate compliance with applicable ambient air quality standards.

The proposed modeling analysis will be conducted using the most recent version as of the date of this protocol (version 15181) of the AERMOD (American Meteorological Society/ Environmental Protection Agency Regulatory Model) modeling system. AERMOD is an enhanced steady-state, Gaussian plume model that incorporates air dispersion based on planetary boundary layer turbulence structure and scaling concepts, including treatment of both surface and elevated sources, and both simple and complex terrain (EPA 2004). The AERMOD modeling system is listed as the recommended model for short-range analysis (up to 50 kilometers) in the United States Environmental Protection Agency (EPA)-maintained Guideline on Air Quality Models, which is published as Appendix W to the Code of Federal Regulations, Title 40, Part 51 (40 CFR 51, Appendix W).

AERMOD has been routinely used for air quality analyses of facilities located in Idaho and elsewhere and is the appropriate model selection for this analysis.

The effects of building-induced downwash will be incorporated into this modeling analysis. Building downwash parameters will be calculated using the most recent version of the Building Profile Input Program (BPIP) with the Plume Rise Model Enhancement (PRIME) algorithm (BPIP-PRIME version 04274).

All receptors will be processed with the AERMOD terrain preprocessor AERMAP (version 11103) to generate receptor terrain elevations and hill height values using 1/3-Arc-Second National Elevation Dataset (NED) elevation data obtained from the National Map Seamless Server (http://www.mrlc.gov/) in a United States Geological Survey (USGS) GeoTIFF file format.

3.2 Model Setup and Application

3.2.1 Model Options

Regulatory default options in AERMOD will be used to estimate the ground-level concentrations for all the pollutants and averaging periods except for NO_2, which is detailed in Section 3.2.5.

3.2.2 Averaging Times

Emissions will be adjusted to account for the appropriate averaging periods in the modeling analysis. For example, for pollutants with a 1-hour averaging period (e.g., CO and NO_2), emissions in lb/hr will be converted to g/sec for input to the model. For CO, modeled emissions will be based on the hourly emission rates. For pollutants with 24-hour averaging periods (e.g., PM), daily emissions in lb/day will be divided by 24 hours/day to arrive at a daily average lb/hr value. For pollutants with annual averaging periods (e.g., $PM_{2.5}$ and NO_2), annual emissions in lb/year will be divided by 8,760 hours/year to arrive at an annual average lb/hr value.

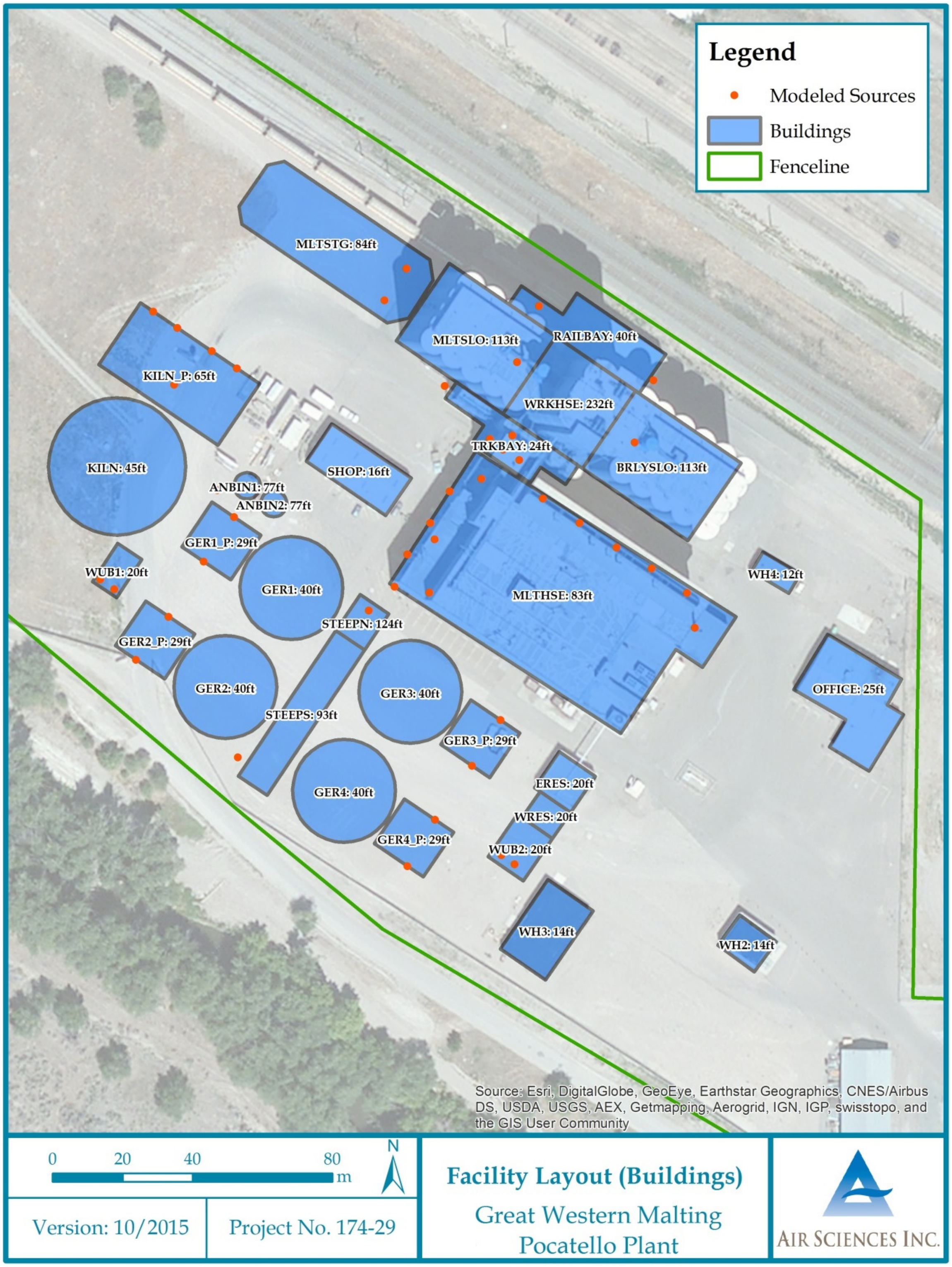
3.2.3 Land Use

Consistent with previous ISC modeling of the GWM facility and based on a review of the current land use surrounding the GWM facility today, the land use in the vicinity of the facility is considered rural under the Auer land use scheme. It should be noted that the "rural" keyword that was applicable for the ISC model is no longer allowed/required for the AERMOD model.

3.2.4 Building Downwash

Figure 3 provides a plot showing the buildings considered in the BPIP analysis and their respective heights above grade.

Figure 3. Facility Layout Map (Buildings)



3.2.5 Chemical Conversion

Regulatory default options in AERMOD will be used to estimate the ground-level concentrations for all the pollutants and averaging periods except for NO_2, which is detailed in the following subsection.

The NO_X emissions from combustion sources are principally composed of nitrogen oxide (NO) and NO_2. Once in the atmosphere, the NO is converted to NO_2 through a chemical reaction with ambient O_3, as follows:

$$NO + O_3 \rightarrow NO_2 + O_2$$

Currently, EPA's Guideline on Air Quality Models (40 CFR 51, Appendix W), presents a three-tiered approach to convert annual NO_X (nitrogen oxides) impacts to annual NO_2 impacts for comparison to the annual NO_2 NAAQS. In EPA memoranda dated June 28, 2010, and March 1, 2011 (EPA 2010 and EPA 2011), the applicability of 40 CFR 51, Appendix W is further discussed in the context of modeling for compliance with the 1-hour NO_2 standard. To address the atmospheric conversion process, EPA recommends the following three-tiered screening approach for evaluating NO_2 impacts:

- Tier 1: Assume total conversion of NO to NO_2.
- Tier 2: Assume representative equilibrium NO_2/NO_X ratio (0.75 for annual and 0.80 for 1-hour).
- Tier 3: A detailed screening method may be used on a case-by-case basis.

For 1-hour NO_2, the model will be initially run assuming full conversion of NO to NO_2. If compliance cannot be demonstrated from this first-tier approach, a second-tier approach utilizing 0.80 as a default ambient ratio for the 1-hour NO_2 standard will be utilized.

If compliance cannot be demonstrated with either of these two tiers, the non-default option of the Ozone Limiting Method (OLM), a Tier 3 method from 40 CFR 51, Appendix W, will be used to estimate the NO_2 1-hour and annual impacts for this analysis. The OLM determines the limiting factor for NO_2 formation by comparing the estimated maximum NO_X concentration and the ambient O_3 concentration. The model assumes a total NO to NO_2 conversion when the ambient O_3 concentration is greater than the estimated maximum NO_X concentration; otherwise it is limited by the ambient O_3 concentration.

It should be noted that AERMOD NO_2 concentrations can be simulated using either OLM or PVMRM. However, EPA guidance (EPA 2011) indicates that preliminary model evaluation results show that the PVMRM option in AERMOD is not inherently superior to the OLM for purposes of estimating cumulative NO_2 concentrations. According to EPA (EPA 2011):

"The PVMRM algorithm as currently implemented may also have a tendency to overestimate the conversion of NO to NO_2 for low-level plumes by overstating the amount of ozone available for the conversion due to the manner in which the plume volume is calculated. The plume volume calculation in PVMRM does not account for the fact that the vertical extent of the plume based on the vertical dispersion coefficient may extend below ground for low-level plumes. This overestimation of the volume of the plume could contribute to overestimating conversion to NO_2."

In addition, results of monitor-to-monitor comparisons from recent studies show generally good model with the use of OLM with the combined plume option OLM (keywords OLMGROUP ALL).

Given PVMRM's tendency to over-predict NO_2 concentrations, the combined plume option (keywords OLMGROUP ALL) of the OLM is appropriate and will be used for this analysis. Key model inputs for both the OLM option in AERMOD are the in-stack ratios of NO_2/NO_X emissions and background ozone concentrations.

Additional input parameters for the OLM option include the following:

- Background O_3 Concentrations – The use of the PVMRM or OLM option in AERMOD requires the input of background O_3 concentrations. The O_3 concentration values may be input as a single value, as hourly values to correspond with the meteorological data, or as a temporally varying profile. GWM will utilize the single background ozone concentration (58 ppb) provided by DEQ. If it is necessary to refine the ozone concentrations to utilize hourly ozone concentration profiles, GWM will discuss further with DEQ.
- Ambient Equilibrium NO_2/NO_X Ratio – The AERMOD default NO_2/NO_X ambient equilibrium ratio of 0.90 will be used for this analysis.
- In-Stack NO_2/NO_X Ratio – The San Joaquin Valley Air Pollution Control District (SJVAPCD) has provided recommended NO_2/NO_X in-stack ratios for a variety of source categories in the California Air Pollution Control Officers Association's (CAPCOA) guidance document for NO_2 1-hour modeling (CAPCOA 2011). The SJVAPCD recommends an NO_2/NO_X in-stack ratio of 10 percent for natural-gas-fired boilers. These values will be used for all GWM combustion sources that burn natural-gas, including the kilns.

3.3 Receptors and Ambient Air Boundary

Because of downwash and relatively cool exhausts, the maximum impacts from the GWM facility are expected to occur at the property line. Consistent with previous modeling of the facility, receptors will be placed along the property line (ambient air boundary) with a spacing of at least 25 meters. For receptors within 1 kilometer of the facility and for receptors in complex terrain to the southwest of the facility, 50-meter grid spacing will be used. A grid spacing of 100 meters will used for receptors out to 5 kilometers from the facility. Finally, for the significant impacts analyses, the grid will be extended to include 500-meter grid spacing to 10 kilometers from the facility and 1,000-meter grid spacing between 10 and 50 kilometers from the facility to define the significant impact areas. The near-field receptors are shown in Figure 4. The far-field receptors are shown in Figure 5.

This ambient air boundary is located around the GWM facility where public access is restricted through a combination of fences, gates, and signage. Receptors within the ambient air boundary will not be modeled.

Figure 4. Near-Field Receptors

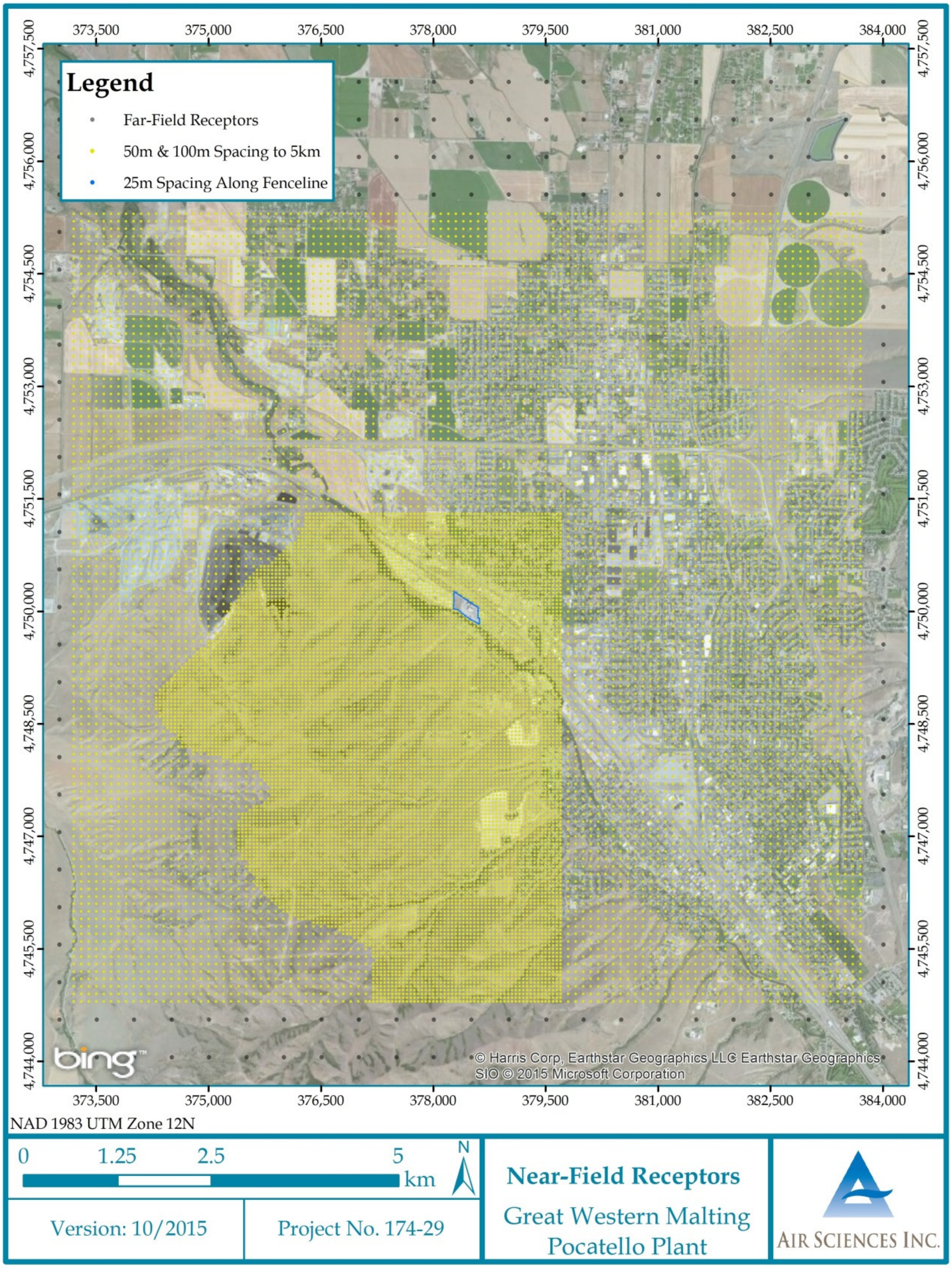
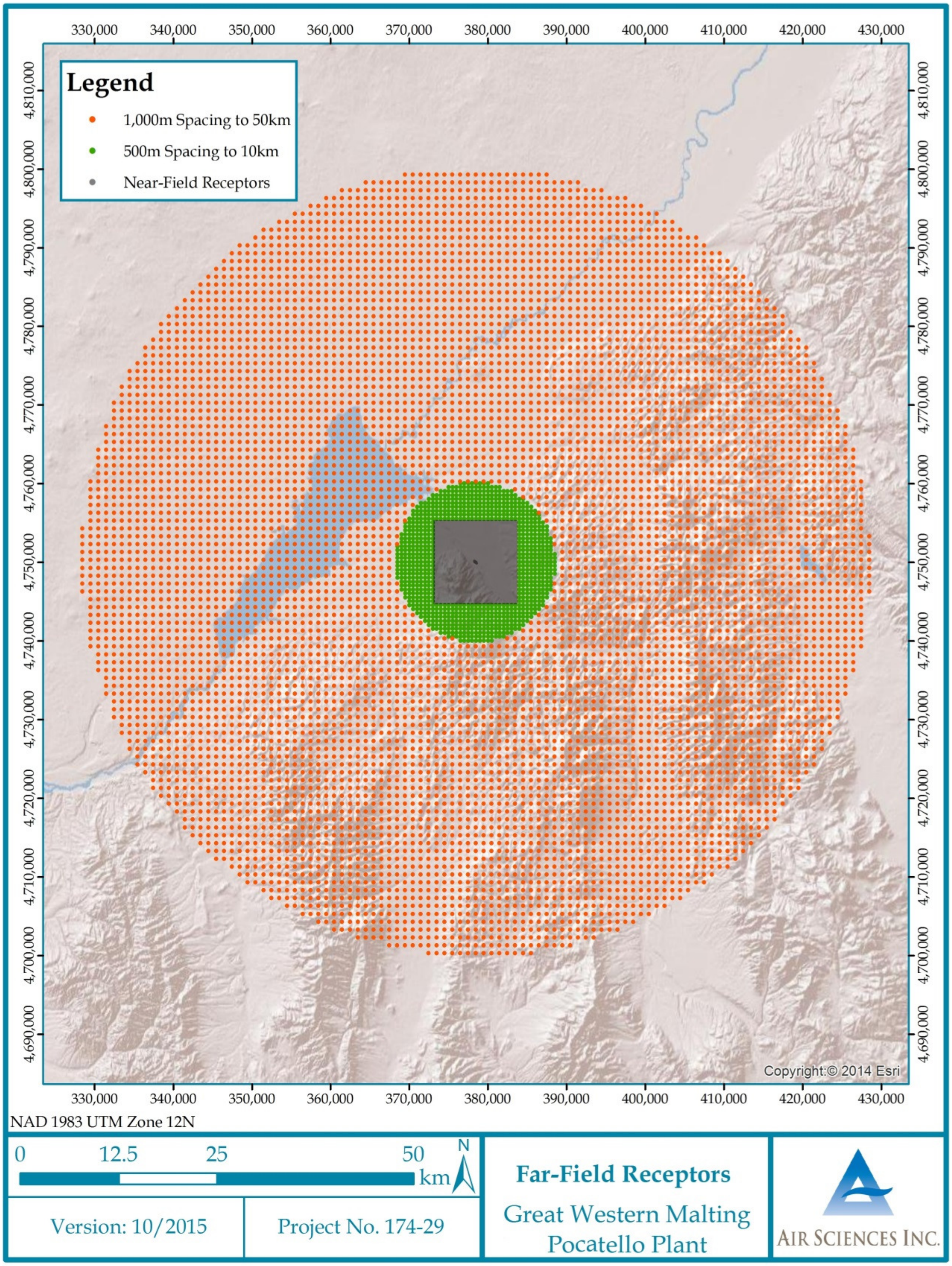


Figure 5. Far-Field Receptors



3.4 Meteorological Data

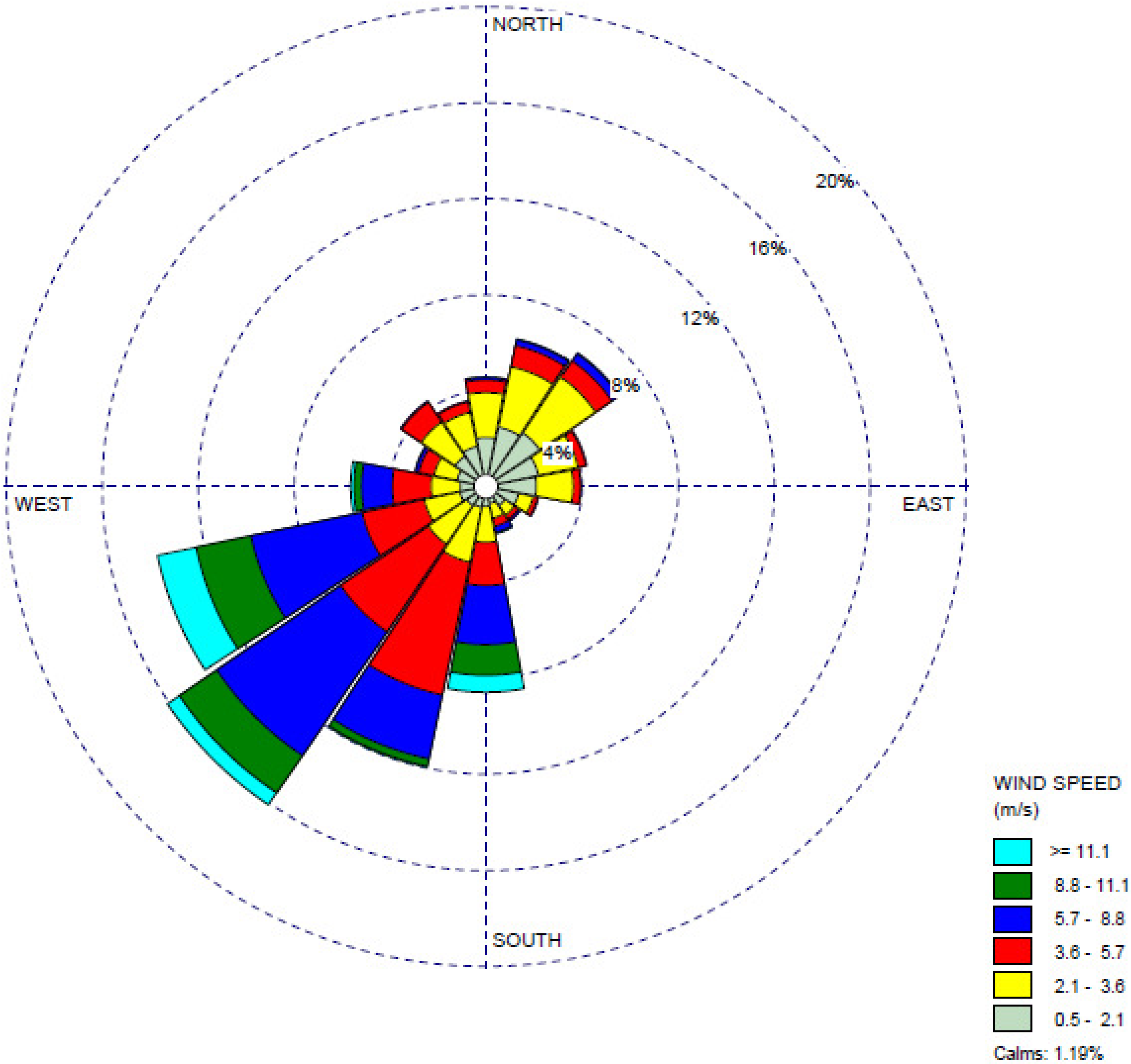
AERMOD requires the input of hourly meteorological data to estimate pollutant concentrations in the ambient air resulting from modeled source emissions. The EPA's Guideline on Air Quality Models (40 CFR 51, Appendix W) states that one year of site-specific data, or five years of representative hourly surface data, should be used for AERMOD dispersion modeling.

DEQ has provided GWM with five years (2008–2012) of AERMOD-ready meteorological data for modeling. The data provided are National Weather Service (NWS) surface meteorological data from the Pocatello Regional Airport in combination with upper-air data (soundings) from Boise, Idaho.

Please note that the AERMOD-ready meteorological data provided to GWM were processed using AERMET version 12345, not the most recent version of AERMET (version 15181). However, version 12345 data will still run in AERMOD version 15181. If DEQ wishes for GWM to run AERMOD with version 15181 meteorological data, GWM requests that DEQ provide the five-year Pocatello/Boise meteorological data set in AERMET version 15181.

The wind frequency distribution diagram for the Pocatello meteorological data set is shown in Figure 6.

Figure 6. Five-Year Wind Frequency Distribution Diagram for Pocatello (2008–2012)



3.5 Background Concentrations

Monitored pollutant concentrations, or background concentrations, are considered to be representative of the prevailing air pollution from the existing sources in the region. These background concentrations are added to the modeled ambient impacts from project emissions to estimate the total ambient concentrations at the modeled receptor locations.

DEQ has provided GWM background concentrations to be used in the NAAQS analysis as shown in Table 8. GWM will utilize the single background values above for the NAAQS compliance demonstration. If it is necessary to refine the background concentrations to demonstrate compliance (i.e., by season or time of day), GWM will discuss further with DEQ.

Table 8. Background Concentrations for Compliance Demonstration

Pollutant	Averaging Period	Background Concentration ($\mu g/m^3$)
CO	1-hour	3,306
	8-hour	1,118
NO_2	1-hour	60.2
	Annual	9.0
$PM_{2.5}$	24-hour	12.0
	Annual	4.3
PM_{10}	24-hour	72.0

4.0 APPLICABLE REGULATORY LIMITS

4.1 Methodology for Evaluation of Compliance with Standards

AERMOD will be run for the facility, and for competing sources (as needed), and the impact will be added to the background concentration for comparison to the NAAQS. For the new sources as part of the expansion project, chlorine and formaldehyde impacts (without addition of background concentrations, which are assumed negligible) will be compared to the AAC and AACC, respectively.

4.1.1 Significant Impact Level (SIL) Analysis

4.1.1.1 Comparison to SILs

AERMOD will be run for the expansion project sources (new sources) for each pollutant and averaging time. If the maximum impact is less than the applicable SIL, then the analysis is assumed completed for that pollutant and averaging time. Table 9 provides the SILs to be considered for the criteria pollutants. If the pollutant impact exceeds the SIL, a full impact analysis will be conducted, which includes impacts from nearby sources.

Table 9. Significant Impact Levels

Pollutant	Averaging Period	SIL ($\mu g/m^3$)
CO	1-hour [3]	2,000
	8-hour [3]	500
NO_2	1-hour [1]	7.5
	Annual [3]	1
$PM_{2.5}$	24-hour [2]	1.2
	Annual [2]	0.3
PM_{10}	24-hour [3]	5

[1] For the 1-hour NO_2, the explicit receptors above the preliminary 1-hour NO_2 SILs (multi-year average on a receptor-by-receptor basis) are considered in the full NAAQS analysis.

[2] For $PM_{2.5}$, the average of the maximum modeled impacts averaged over five years on a receptor-by-receptor basis is utilized to determine the significant impact area (SIA).

[3] For these pollutants and averaging periods, the maximum modeled concentrations are used to determine the SIAs.

Initially, the SIA is determined for every relevant averaging time for a particular pollutant. The final SIA for that pollutant is the largest area for each of the various averaging times. According to the EPA's Draft New Source Review Workshop Manual (EPA 1990), the SIA is a circular area with a radius extending from the source to: 1) the most distant point where approved dispersion modeling predicts a significant ambient impact will occur, or 2) a modeling receptor distance of 50 kilometers, whichever is less. Therefore, a SIA cannot be greater than 50 kilometers for any pollutant. The SIA radius for GWM will be limited to 50 kilometers because that is the upper limit of AERMOD's regulatory range and EPA has clarified that an SIA radius should not exceed 50 kilometers.

For the 1-hour NO_2 SIA, following EPA guidance, the receptors to be considered for the 1-hour NO_2 analyses are based on the explicit receptors that have a multi-year average impact greater than the SILs, rather than a traditional impact area based on a circular radius.

4.1.1.2 TAP Analysis

A summary of the TAPs to be modeled and their respective AACs or AACCs are provided in Table 10.

Table 10. AACs and AACCs for Compliance Demonstration

Pollutant	Type	Avg. Period	AACC (μg/m³)	AAC (mg/m³)	Form
Chlorine	Non-carcinogen	24-hour	---	0.15	Maximum daily
Formaldehyde	Carcinogen	Annual	7.7E-02	---	Maximum annual

4.2 Cumulative NAAQS Impact Analysis

4.2.1 Ambient Air Quality Standards

Ambient air quality standards are maximum concentrations of pollutants in ambient air that are considered protective of the public health. These standards are established by EPA for air pollutants with known or anticipated human health effects. The estimated total ambient concentrations (modeled concentrations plus applicable background concentrations) from the modeling analysis will be compared with the NAAQS for compliance demonstration.

The NAAQS provided in DEQ's modeling guidelines (IDEQ 2013) mention that the NAAQS levels for modeling consideration are incorporated into Idaho Air Rules Section 107.03.b. (revised as of July 1, 2014). This rule incorporates the federal NAAQS listed in 40 CFR 50 by direct reference into the Idaho air quality regulations. Since the Idaho modeling guidelines are dated 2013 and because the NAAQS for annual PM_{10} have been revoked by EPA, GWM assumes that the NAAQS to be considered in the modeling analysis, as listed in Table 11, only include the current federal NAAQS levels (i.e., not the revoked annual PM_{10} standards).

Table 11. NAAQS for Compliance Demonstration

Pollutant	Averaging Period	NAAQS ($\mu g/m^3$)	Form
CO	1-hour	40,000	Not to be exceeded more than once per year
	8-hour	10,000	
NO_2	1-hour	188	98th percentile of 1-hour daily maximum concentrations, averaged over 3 years
	Annual	100	Annual mean
$PM_{2.5}$	24-hour	35	98th percentile, averaged over 3 years
	Annual	12	Annual mean, averaged over 3 years
PM_{10}	24-hour	150	Not to be exceeded more than once per year on average over 3 years

EPA has also promulgated a NAAQS for lead (Pb); however, Pb emissions at the GWM facility are expected to be minimal; therefore, Pb is not addressed further. In addition, the GWM project emissions of SO_2 do not trigger modeling, and these pollutants are not addressed further.

4.2.2 Competing Sources

If the pollutant impact exceeds the SIL, a full impact analysis will be conducted, which includes impacts from nearby sources. It is anticipated that the facility will have significant impacts and a competing source inventory will be needed. GWM requests that DEQ provide competing source inventories for PM_{10}, $PM_{2.5}$, NO_X, and CO from DEQ for sources located within 100 kilometers of the GWM facility. This inventory will be screened to identify the appropriate sources for use in the full impact model. A common long-term practice for selecting the "nearby" sources for explicit modeling was to follow a very prescriptive procedure in EPA's draft New Source Review Workshop Manual (EPA 1990). If the source is within GWM's SIA, then it will be explicitly modeled. For sources beyond the SIA, a Range of Influence (ROI) from the competing source will be determined from the emissions (Q - in TPY) divided by 20 following North Carolina's "20D" approach. The ROI radius for competing sources will be limited to 50 kilometers because that is the upper limit of AERMOD's regulatory range. If a competing source's long-term ROI overlaps GWM's long-term SIA, then that competing source will be modeled.

For the short-term analysis (e.g., 1-hour NO_2), an additional review step may be conducted. EPA recently clarified that "following such [Manual] procedures in a literal and uncritical manner may in many cases result in cumulative impact assessments that are overly conservative" (EPA 03/11).[1] The Guideline on Air Quality Models (40 CFR 51, Appendix W) is consistent with this approach, stating that professional judgment is required for ascertaining which sources should be explicitly modeled and which sources can be represented through ambient monitoring data. Per Section 8.2.3 of Appendix W, "all sources expected to cause a significant concentration gradient in the vicinity of the [applicant's source] should be explicitly modeled." This does not mean that a distant source could not have an overlapping impact. Rather, it suggests that this overlapping impact can be addressed using available monitoring data and incorporated in the background concentration, rather than by explicitly modeling the distant source. Thus, the concentration gradient screen, if applied, will be addressed on a source-by-source basis.

Once screened, the competing sources will then be included in the modeling for all pollutants and averaging times that are over the SIL. Only receptors within the SIA will be evaluated. For the short-term and long-term NO_2 evaluation, the SIL will be based on the NO_2 concentration.

4.3 Model Results and Compliance with NAAQS, AAC, and AACC

For the cumulative NAAQS analysis, following DEQ modeling guidance (IDEQ 2013, page 51), the following design concentrations will be used when demonstrating compliance with the NAAQS.

CO

- 1-hour averaging period – maximum of second highest ambient concentrations at each receptor
- 8-hour averaging period – maximum of second highest ambient concentrations at each receptor

NO_2

- 1-hour averaging period – maximum of 5-year averages (at each modeled receptor) of the 98th percentile of the annual distribution (equal to the 8th high) of maximum daily 1-hour ambient concentrations
- Annual averaging period – maximum of ambient concentrations at each receptor

PM_{10}

- 24-hour averaging period – per EPA, "the projected 24-hour average concentrations will not exceed the 24-hour NAAQS more than once per year on average." Since five years of NWS data will be used in the GWM modeling analysis, then the design concentration

[1] EPA OAQPS. Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard. From Tyler Fox, Leader – Air Quality Monitoring Group, C439-01, March 1, 2011.

is the sixth highest 24-hour ambient concentration that occurred at each receptor over that five-year period.

For the cumulative NAAQS analyses for $PM_{2.5}$, GWM proposes an alternate approach from the DEQ modeling guidelines (IDEQ 2013). Regarding cumulative $PM_{2.5}$ modeling, DEQ modeling guidelines have not been updated to reflect EPA's current/final modeling guidance on $PM_{2.5}$. Current DEQ guidelines request the use of the maximum (high-first-high) modeled concentrations in the cumulative NAAQS analysis. However, since the time the DEQ modeling guidelines were written in 2013, EPA has released final modeling guidance that allows the use of the 98th percentile (high-eighth-high) 24-hour modeled $PM_{2.5}$ concentrations in the cumulative NAAQS analysis (EPA 2014, Page 58). Thus, GWM proposes the following for $PM_{2.5}$ modeling of the expansion project:

$PM_{2.5}$

- 24-hour averaging period – maximum of 5-year averages (at each modeled receptor) of the 98th percentile of the annual distribution (equal to the 8th high) of 24-hour concentrations
- Annual Averaging Period – maximum of multi-year average of annual ambient concentrations at each receptor

For criteria pollutants, the maximum modeled design concentrations will be determined and added to the background concentration. These estimated total ambient concentrations (modeled concentrations plus background concentrations) will be compared to the applicable NAAQS and presented in tabular form (along with impacts receptor locations). The locations of the maximum modeled impacts will also be presented in graphical form. Impacts of chorine and formaldehyde for the TAPs analysis will be provided in tabular form.

5.0 REFERENCES

CAPCOA. 2011. *Modeling Compliance of The Federal 1-Hour NO_2 NAAQS*. October 27, 2011.

EPA. 1990. *Draft – New Source Review Workshop Manual.* October 1990.

EPA. 2004. *AERMOD: Description of Model Formulation*. EPA-454/R-03-004. September 2004.

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EPA. 2014. *Guidance for $PM_{2.5}$ Permit Modeling*. Memorandum from Stephen D. Page (EPA Director) to Regional Air Division Directors, Regions 1-10. May 20, 2014. Accessed October 2, 2015. http://www.epa.gov/scram001/guidance/guide/Guidance_for_PM25_Permit_Modeling.pdf.

IDEQ. 2013. *State of Idaho Guideline for Performing Air Quality Impact Analyses*. September 2013.

Appendix A – Process Flow Diagrams

(GWM preapplication meeting information 08072015.pdf)

DEQ AIR QUALITY PROGRAM
1410 N. Hilton, Boise, ID 83706
For assistance, call the
Air Permit Hotline: 1-877-5PERMIT

Preapplication Form
8/11/14

Please see instructions on next page before filling out the form. All information is required.

Identification

1. Facility name	2. Existing facility identification number	Check if new facility (not yet operating)
Great Western Malting Company	005-00035	☐

Facility Information

3. Primary facility permitting contact name: Jay Hamachek
Contact type: Facility permitting contact

Telephone number: (360) 991-0580
E-mail: jhamachek@graincorpmalt.com

4. Physical address of permitted facility (street/city/county/state/zip code): 1666 Kraft Rd/ Pocatello/ Bannock County/ ID/ 83204

5. Identify any adjacent or contiguous facility this company owns and/or operates: None

6. Specify type of application: ☒ Permit to construct ☐ Exemption ☐ Tier II permit

7. Facility process description: Barley malting facility- See Attachment 1 for more detail

8. Project description: Adding malting capacity- See Attachment 2 for more detail

9. Is the preapplication meeting required in response to a DEQ compliance or enforcement action? ☐ Yes ☒ No

Note: The applicant is expected to review the following material prior to the preapplication meeting:
- Emissions inventory
- Regulatory review
- Modeling, if required

Attachment 1
Process Description- Existing Facility

Great Western Malting produces high quality malted barley that is a basic ingredient in beer. Process flow diagrams associated with this process narrative are provided in Figure 1 (Material Handling Process Flow) and Figure 2 (Malthouse Process Flow).

Barley is received by truck or railcar and unloading operations occur at the Truck Bay (TB) and Rail Bay (RB). During unloading, the trucks or railcars discharge barley into hoppers, from which the barley is conveyed through the headhouse. Unloading operations result in the generation of particulate matter (PM) emissions. The truck bay receiving pit is equipped with side draw vacuums with exhaust to baghouse #1 (BH1). Hopper-type trucks account for a majority of the truck receiving operations. These trucks and the railcar unloading operations employ choke feed to the receiving pit to minimize fugitive particulate matter emissions.

The barley is transferred through the headhouse to the barley storage silos. PM emissions generated by headhouse transfer operations are control by BH1. Material collected by all of the centralized baghouse systems (BH1, BH2, and BH3) is sent to a pellet mill. The barley is then cleaned and graded with transfers and the cleaning device controlled by BH2. “Thin” barley is transferred to Feed Barley transfer bins and this material is trucked offsite and used as animal feed. Feed Barley transfer operations are controlled by BH1. Feed Barley truck loadout operations are controlled by a cyclone side vacuum draw system that exhausts to BH3.

After cleaning, the barley is transferred to the malthouse where it is steeped by placing it in large tanks with cool, oxygen-enriched water. Following steeping, the barley is dropped to one of six temperature and humidity controlled germination beds and allowed to grow. The steeping and germination processes also are served by chilled water systems. The six germination beds are periodically sanitized with Hypochlorite resulting in minor emission of chlorine through the Germination Bed Exhaust emission points (GBE 1&4, GBE 2&5, and GBE 3&6). The steeping and germination process requires heated air provided by two natural gas-fired hot water boilers that exhaust combustion byproducts to a common stack (BS1).

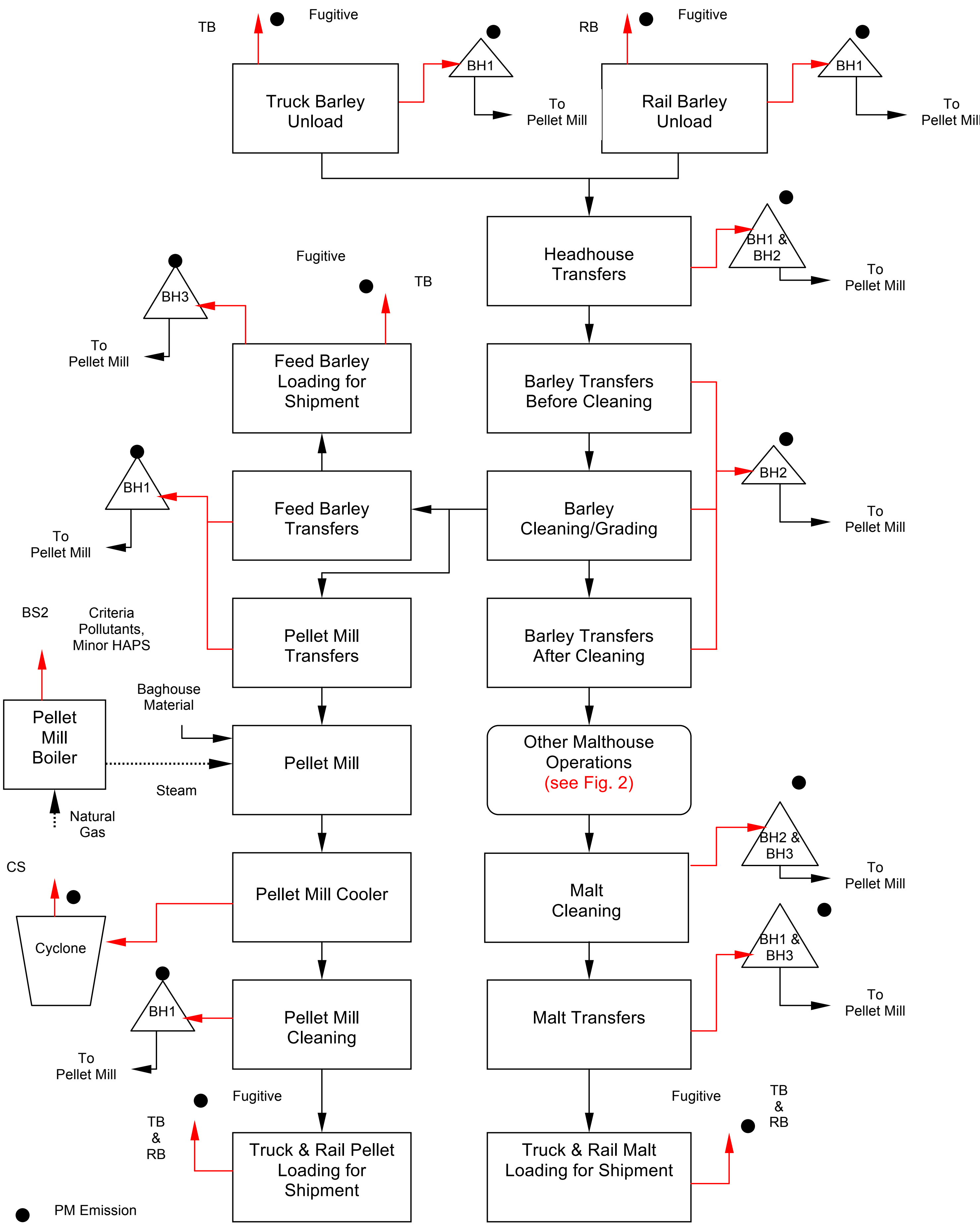
Following steeping and germination, “green” malt is dried in an indirect natural gas-fired malt kiln. The malt kiln has two levels. Clean malt enters the upper deck of the kiln and is dried. The barley is then transferred to the lower deck of the kiln, where it is further dried to about 4 percent moisture content. During a portion of the kilning, sulfur may be burned in a sulfur stove and exhausted to the kiln primarily as sulfur dioxide. The sulfur dioxide serves as a fungicide, bactericide, and preservative. The kiln emits particulate matter, volatile organic compounds (VOCs), and sulfur dioxide. These emissions are vented through one stack designated as KSE. The malt kiln burner stacks (KS1-KS5) are located within the main kiln stack.

The malted barley is then cleaned and transferred to the malt storage silos until it is shipped. PM generated during the cleaning is collected in BH2 baghouse and transfers are collected in the BH3 baghouse.

Cleaning byproducts and material collected by the baghouses are sent to a pellet mill where the material is pelletized and shipped offsite. Loadout of pelletized material occurs via truck and results in fugitive PM emissions. The pellet mill mixer requires steam provided by a steam boiler that discharges combustion byproducts through BS2.

The malt is shipped by railcar or truck. Particulate matter is generated during loading. These emissions occur at the Rail Bay (RB) and Truck Bay (TB) emission points.

Fugitive road dust is generated by truck deliveries to, and shipments from the plant. The trucks travel approximately 1550 feet on the paved access roads. Sweko trucks that remove some waste material from the facility travel approximately 600 feet on a paved road.



PM Emission

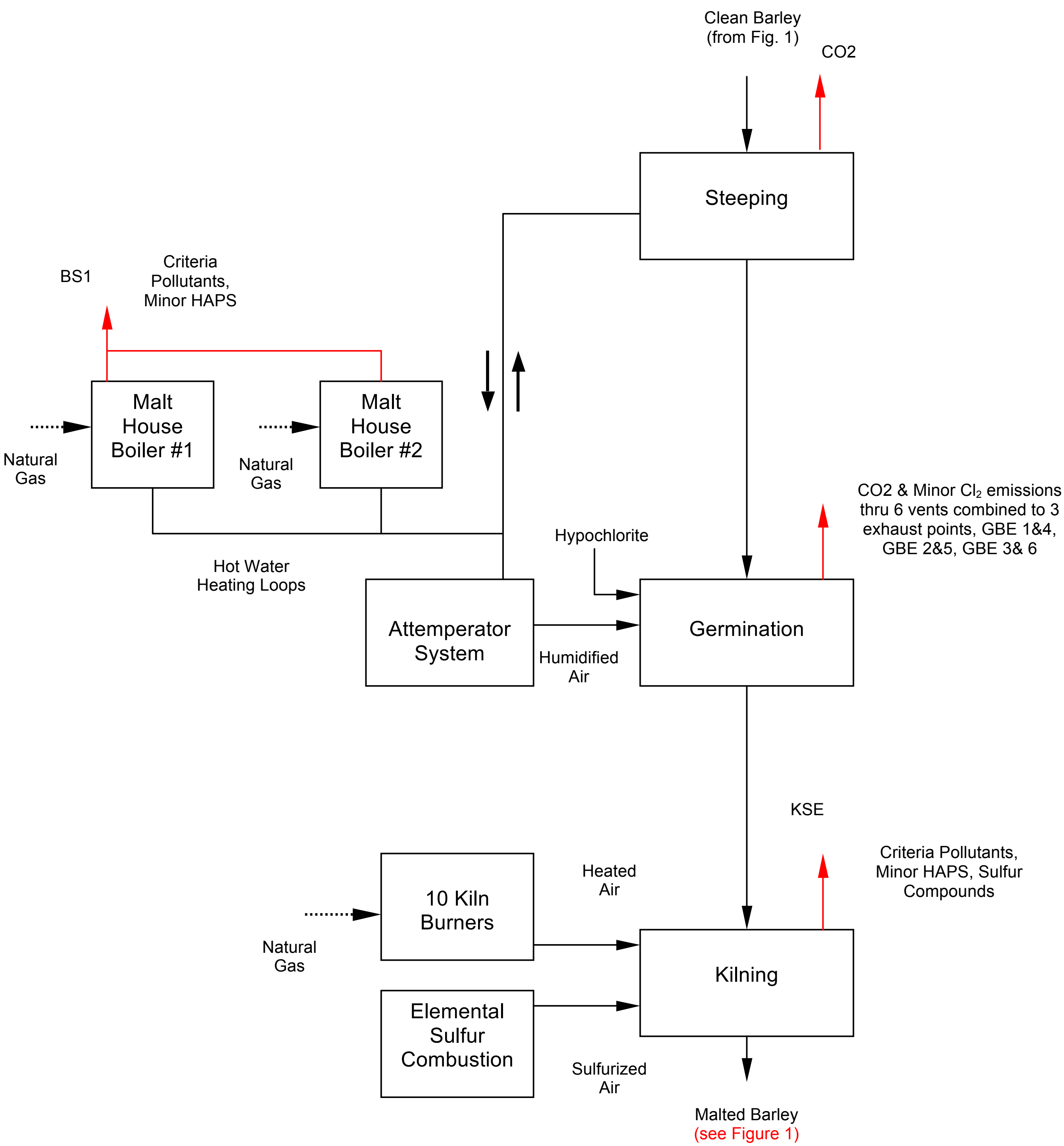
Product or Byproduct Flow

Air Emission Flow

Figure 1 – GWM Material Handling Process

RB = Rail Bay; TB = Truck Bay; BH = Baghouse; CS = Cyclone Stack; BS = Boiler Stack

doc



Product Flow Unless Otherwise Noted

Air Emission Flow

KSE = Kiln Stack Exhaust; BS1 = Boiler Stack 1

Figure 2 –Existing Malthouse Process Flow

Attachment 2
Expansion Project Description

Great Western Malting is planning to increase the malting capacity of the Pocatello plant. A summary of the changes involved in the expansion project is provided below.
(Note that the design for the expansion is not final, so the following information is preliminary and may be revised for the air permit application.)

Barley Handling

No changes to the barley handling equipment at the existing plant are planned. The equipment is sized to handle the additional barley needed for the new malting equipment. The main change will be to increase production throughput to a total of about 324,000 MT barley/year. The proposed production rate changes are:

Production Throughput Before and After Expansion (MT/year)

Grain	Existing	Added	Facility Total
Barley	144,000	180,000	324,000
Malt	130,000	162,000	292,000
Pelletized/Feed	12,000	15,000	27,000

There will be a couple of new barley transfer points as barley is conveyed to the new malting equipment. New dust collector(s) will be added to capture particulate matter from the barley transfers.

Malting

The project will add new malting equipment to the facility. The existing malting equipment will be unchanged. The new malting equipment will include 16 new steeps, 4 new germination vessels, and 1 new kiln. A process flow diagram for the malting expansion is provided in Figure 3.

The kiln will use 4 air-to-air heat exchangers to provide the drying air for the kiln. The burners for the heat exchangers will be natural gas-fired, each at 5.5 MM Btu/hr heat input capacity. Each burner will have its own exhaust stack. The kiln will include the capability to burn sulfur, similar to the existing kiln sulfur burners. Air from the kiln will be discharged from a single stack.

Each steep will have its own exhaust stack and each germination vessel will have two exhaust stacks. Just like in the existing germination equipment, the new germination vessels will be sanitized using sodium hypochlorite, which may produce minor amounts of chlorine emissions.

The hot water for germination will be provided by 4 new natural gas-fired boilers. Each boiler will have a 2 MM Btu/hr heat input capacity.

Biogenic carbon dioxide (CO2) is given off during the malting process and generated from combustion equipment. This pollutant will need to be added to the permit for the existing and new equipment.

Malt Handling

After the malt is dried in the kiln, it will be cleaned and placed into storage. The stored malt will be cleaned again before it is loaded into trucks or railcars and shipped offsite.

The increase in malt production will require the addition of storage and cleaning equipment to the existing plant. The plan is to:

- Add 8 new 750 MT malt storage silos
- Replace some existing kiln malt cleaning equipment with new equipment (scalper and aspirator). The existing baghouses have enough capacity and will be used to control dust.
- Add new stored malt cleaners. The existing baghouses will be used to control dust.
- Add 2 new malt analysis bins with filters
- Add 4 new 40 MT truck loadout bins and chutes
- Add a cyclone for conveying by-products to the by-product bin. A dust collector will be used to control emissions from the cyclone exhaust.
- Add new conveyors and transfers as needed to move the malt and other materials. Dust from these activities will be controlled using the existing baghouses or by the addition of new dust collectors.

The pellet mill has enough capacity to handle the barley residue, malt by-products and baghouse material from the expansion so no changes are planned to the pellet mill system or pellet boiler.

There will be an increase in the number of trucks delivering barley and supplies to and shipping malt and other materials from the facility. As a result, there will be an increase in fugitive dust from the paved onsite roads.

Preliminary Information- Design Subject to Change

NOTES:
1. FILLING TIME OF 8 STEEPS WITH WATER, MAX 60MIN.
2. DRAIN TIME FOR ALL 8 STEEPS TO BE <30MIN.

Figure 3

REV	DESCRIPTION	DRN	CKD	DATE
P2	GENERAL UPDATE BY JIM HALLETT PRIOR TO 2nd DESIGN WORKGROUP WITH JHK	GC	JH	19.06.15

Great Western Malting Co.

SCALE	N.A.
DRAWN	G. Chahine
DATE	28.04.2015
DESIGNED	JIM HALLETT
DATE	28.04.2015
CHECKED	
APPROVED	

PROJECT: POCATELLO MALTINGS EXPANSION

TITLE: PROCESS FLOW DIAGRAM

PROJECT No.: POC001

DRAWING STATUS: DEVELOPMENT

DRAWING No.: 00-PFD-001

REVISION: P2

Appendix D – Modeling Protocol Addendum #1

AIR SCIENCES INC.

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Addendum #1 to the Air Quality Modeling Protocol: Great Western Malting Facility in Pocatello, Idaho

PREPARED FOR:
GREAT WESTERN
MALTING CO.

PROJECT NO. 174-29-1
OCTOBER 2015

Addendum Background

The Great Western Malting Co. (GWM) is planning to increase the malting capacity of its malting facility located in Pocatello, Idaho. The existing malt house is located at 42° 53′ 35.6″ N and 112° 29′ 17.2″ W. In early October 2015, GWM submitted a dispersion modeling protocol was submitted the Idaho Department of Environmental Quality (IDEQ) that outlined the approaches and methods used in the upcoming modeling analysis. Although the methodology was outlined in detail, it was noted in the protocol that it may be necessary to refine the background concentrations used in that analysis (see page 21 for the ozone background and page 27 for the ambient backgrounds). Currently, GWM has found the Tier 1 and Tier 2 NO_2-to-NO_X conversion approaches are too conservative to demonstrate compliance. Thus, GWM is looking to apply a case-by-case Tier 3 NO_2-to-NO_X conversion approach (specifically the OLM approach) using concurrent hourly ozone from the Craters of the Moon National Monument monitoring station.

Per communications with DEQ, this protocol addendum provides additional justification for a proposed Tier 3 modeling approach needed to demonstrate NO_2 modeling compliance of the facility. For ease of review, this document retains the original modeling protocol's Section 3.5.2 below for context here, and provides the revised discussion and justification in the second section.

3.5.2 Chemical Conversion (Original Protocol)

Regulatory default options in AERMOD will be used to estimate the ground-level concentrations for all the pollutants and averaging periods except for NO_2, which is detailed in the following subsection.

The NO_X emissions from combustion sources are principally composed of nitrogen oxide (NO) and NO_2. Once in the atmosphere, the NO is converted to NO_2 through a chemical reaction with ambient O_3, as follows:

$$NO + O_3 \rightarrow NO_2 + O_2$$

Currently, EPA's Guideline on Air Quality Models (40 CFR 51, Appendix W), presents a three-tiered approach to convert annual NO_X (nitrogen oxides) impacts to annual NO_2 impacts for comparison to the annual NO_2 NAAQS. In EPA memoranda dated June 28, 2010, and March 1, 2011 (EPA 2010 and EPA 2011), the applicability of 40 CFR 51, Appendix W is further discussed in the context of modeling for compliance with the 1-hour NO_2 standard. To address the atmospheric conversion process, EPA recommends the following three-tiered screening approach for evaluating NO_2 impacts:

- Tier 1: Assume total conversion of NO to NO_2.
- Tier 2: Assume representative equilibrium NO_2/NO_X ratio (0.75 for annual and 0.80 for 1-hour).
- Tier 3: A detailed screening method may be used on a case-by-case basis.

For 1-hour NO_2, the model will be initially run assuming full conversion of NO to NO_2. If compliance cannot be demonstrated from this first-tier approach, a second-tier approach utilizing 0.80 as a default ambient ratio for the 1-hour NO_2 standard will be utilized.

If compliance cannot be demonstrated with either of these two tiers, the non-default option of the Ozone Limiting Method (OLM), a Tier 3 method from 40 CFR 51, Appendix W, will be used to estimate the NO_2 1-hour and annual impacts for this analysis. The OLM determines the limiting factor for NO_2 formation by comparing the estimated maximum NO_X concentration and the ambient O_3 concentration. The model assumes a total NO to NO_2 conversion when the ambient O_3 concentration is greater than the estimated maximum NO_X concentration; otherwise it is limited by the ambient O_3 concentration.

It should be noted that AERMOD NO_2 concentrations can be simulated using either OLM or PVMRM. However, EPA guidance (EPA 2011) indicates that preliminary model evaluation results show that the PVMRM option in AERMOD is not inherently superior to the OLM for purposes of estimating cumulative NO_2 concentrations. According to EPA (EPA 2011):

> *"The PVMRM algorithm as currently implemented may also have a tendency to overestimate the conversion of NO to NO_2 for low-level plumes by overstating the amount of ozone available for the conversion due to the manner in which the plume volume is calculated. The plume volume calculation in PVMRM does not account for the fact that the vertical extent of the plume based on the vertical dispersion coefficient may extend below ground for low-level plumes. This overestimation of the volume of the plume could contribute to overestimating conversion to NO_2."*

In addition, results of monitor-to-monitor comparisons from recent studies show generally good model with the use of OLM with the combined plume option OLM (keywords OLMGROUP ALL).

Given PVMRM's tendency to over-predict NO_2 concentrations, the combined plume option (keywords OLMGROUP ALL) of the OLM is appropriate and will be used for this analysis. Key model inputs for both the OLM option in AERMOD are the in-stack ratios of NO_2/NO_X emissions and background ozone concentrations.

Additional input parameters for the OLM option include the following:

- Background O_3 Concentrations – The use of the PVMRM or OLM option in AERMOD requires the input of background O_3 concentrations. The O_3 concentration values may be input as a single value, as hourly values to correspond with the meteorological data, or as a temporally varying profile. GWM will utilize the single background ozone concentration (58 ppb) provided by DEQ. If it is necessary to refine the ozone concentrations to utilize hourly ozone concentration profiles, GWM will discuss further with DEQ.
- Ambient Equilibrium NO_2/NO_X Ratio – The AERMOD default NO_2/NO_X ambient equilibrium ratio of 0.90 will be used for this analysis.
- In-Stack NO_2/NO_X Ratio – The San Joaquin Valley Air Pollution Control District (SJVAPCD) has provided recommended NO_2/NO_X in-stack ratios for a variety of source categories in the California Air Pollution Control Officers Association's (CAPCOA) guidance document for NO_2 1-hour modeling (CAPCOA 2011). The SJVAPCD recommends an NO_2/NO_X in-stack ratio of 10 percent for natural-gas-fired boilers. These values will be used for all GWM combustion sources that burn natural-gas, including the kilns.

3.5.2 Chemical Conversion with Additional Discussion and Justification of Tier 3 NO_2 Modeling Approach (Revised)

To demonstrate modeled NO_2 compliance of the facility, GWM proposes a Tier 3 (NO_2) modeling approach (OLMGROUP ALL) using hourly ozone data from nearby Craters of the Moon National Monument. EPA characterizes a Tier 3 modeling approach as a general category of "detailed screening methods" which may be considered on a case-by-case basis.

EPA recommends the use of the OLM/OLMGROUP ALL method and states in their guidance memo "Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-Hour NO_2 National Ambient Air Quality Standard" (EPA 2011) that:

> "…preliminary results of hourly NO_2 predictions for Palaau and New Mexico show generally good performance for the PVMRM and OLM/OLMGROUP ALL options in AERMOD. We believe that these additional model evaluation results lend further credence to the use of these Tier 3 options in AERMOD for estimating hourly NO_2 concentrations, and we recommend that their use should be generally accepted provided some reasonable demonstration can be made of the appropriateness of the key inputs for these options, the in-stack NO_2/NOx ratio and the background ozone concentrations."

The use of the OLM option in AERMOD requires the input of background O_3 concentrations and in-stack NO_2/NOx ratios. The O_3 concentration values may be input as a single value, as hourly values to correspond with the meteorological data, or as a temporally varying profile. For this analysis, DEQ has initially provided GWM a single design concentration background ozone concentration (58 ppb) derived from the NW Airquest database using a model-monitor interpolation process for data from 2009 through 2011. However, EPA notes in their guidance memo "Applicability of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard" (EPA 2010) that:

> "Both OLM and PVMRM rely on the same key inputs of in-stack NO_2/NOx ratios and hourly ambient ozone concentrations. Although both methods can be applied within the AERMOD model using a single "representative" background ozone concentration, it is likely that use of a single value would result in very conservative estimates of peak hourly ambient concentrations since its use for the 1-hour NO_2 standard would be contingent on a demonstration of conservatism for all hours modeled."

This is exactly this level of conservatism (e.g. single value for ozone) that GWM is facing. Thus, GWM wishes to utilize the Tier 3 method with concurrent hourly ozone to address this conservatism. GWM believes the use of hourly ozone data is supported by EPA guidance (EPA 2010) as an integral part of a Tier 3 NO_2 analysis methodology outlined by EPA.

From strictly a policy point of view, the use of hourly ozone in the Tier 3 methodology has been accepted by multiple agencies (Alaska, California, Iowa, Minnesota, Nevada, Connecticut to name a few) and is often outlined in their modeling guidance. In many cases, these agencies provide the hourly ozone set to be used in the analysis. Thus, there is precedence for this approach within the current regulatory arena.

EPA has raised three issues regarding the use of hourly ozone data for NO_2 modeling:

1) the hourly monitored ozone concentrations used with the Tier 3 OLM and PVMRM options must be concurrent with the meteorological data period),

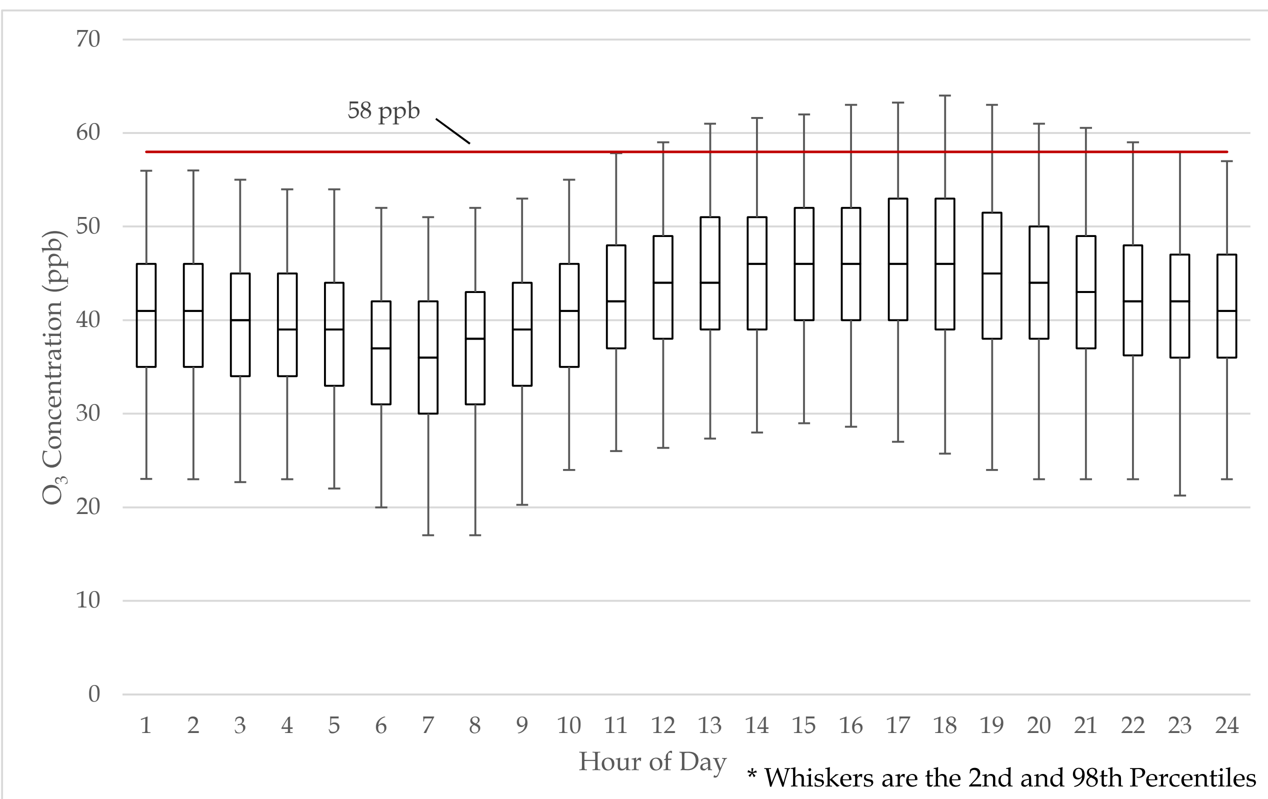
2) that the data are appropriately filled, and

3) the ozone monitor be sufficiently far from any local NOx emission sources to avoid any bias due to NOx scavenging.

The Craters of the Moon National Monument ozone dataset is a high quality ozone data set available from the National Park Service. Craters of the Moon National Monument is located within the same air shed as Pocatello, is representative of the conditions in the GWM modeling domain, and is concurrent with the five years of meteorological data to be used for AERMOD modeling. Because there are few nearby sources of NOx emissions in the vicinity of the Craters of the Moon ozone monitor, the Craters of the Moon ozone data is would not be subject to ozone scavenging from local NO_X emission sources. Thus, the data set provides a representative temporal ozone concentration for the GWM project. Furthermore, GWM is proposing to use the DEQ-provided NW Airquest 58 ppb ozone value to conservatively fill any hours of missing Craters of the Moon ozone data.

Figure 1 presents a box-and-whisker plot of the range of hourly ozone concentrations measured at Craters of the Moon by time of day for five years (2008 – 2012) concurrent with the meteorological dataset to be used for modeling. The lower and upper whiskers represent the 2nd and 98th percentile concentrations respectively, the lower box spans the 25th to 50th percentile, and the upper box spans 50th to 75th percentile. The DEQ provided ozone value of 58 ppb value is indicated by a red line in Figure 1 and is the same magnitude as the upper percentile ozone concentrations measured at Craters of the Moon data set. As expected, the hourly ozone concentrations vary throughout the day and are lowest during the early morning hours and higher during the later afternoon daytime hours when photochemical reactions create ozone. This pattern is ignored when a single value for the ozone concentration is used, thus over predicting NO_2 conversion in the night and early morning hours, especially during the morning hours when GWM's 1-hour NO_2 modeled impacts are the highest. GWM asserts that the use of hourly ozone data in the GWM modeling analysis is a necessary refinement to capture realistic diurnal patterns and ozone concentrations representative of the GWM modeling domain.

Figure 1. Box-and-Whisker Plot of Hourly Ozone Concentrations by Time of Day - Craters of the Moon



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Appendix E –Summary of Modeling Emission Inventory

Source ID	New or Existing	Daily PM_{10} (lb/day)	Daily PM_{10} (lb/hr daily avg.)	Daily PM_{10} (g/sec)	Daily $PM_{2.5}$ (lb/day)	Daily $PM_{2.5}$ (lb/hr daily avg.)	Daily $PM_{2.5}$ (g/sec)	Annual $PM_{2.5}$ (lb/yr)	Annual $PM_{2.5}$ (lb/hr annual avg.)	Annual $PM_{2.5}$ (g/sec)	Hourly NOx (lb/hr)	Hourly NOx (g/sec)	Annual NOx (lb/yr)	Annual NOx (lb/hr annual avg.)	Annual NOx (g/sec)	Hourly CO (lb/hr)	Hourly CO (g/sec)	Daily Cl2 (lb/day)	Daily Cl2 (lb/hr daily avg.)	Daily Cl2 (g/sec)	Annual CH_2O (lb/hr annual avg.)	Annual CH_2O (g/sec)
STC1F	New	0.72	0.030	0.0038	0.12	0.005	0.0006	5.7	0.001	0.0001												
STC2F	New	0.72	0.030	0.0038	0.12	0.005	0.0006	5.7	0.001	0.0001												
GV1-GV4 *	New																	12.90	0.538	0.0677		
K2	New	42.96	1.790	0.2255	27.17	1.132	0.1427	8734.4	0.997	0.1256												
NMLF	New	0.98	0.041	0.0052	0.17	0.007	0.0009	5.2	0.001	0.0001												
BA1F	New	0.98	0.041	0.0052	0.17	0.007	0.0009	2.6	0.0003	0.00004												
BA2F	New	0.98	0.041	0.0052	0.17	0.007	0.0009	2.6	0.0003	0.00004												
KBPCF	New	0.16	0.007	0.0008	0.16	0.007	0.0008	20.1	0.002	0.0003												
NMC3F	New	0.72	0.030	0.0038	0.12	0.005	0.0006	5.2	0.001	0.0001												
MBCF	New	0.20	0.008	0.0010	0.03	0.001	0.0002	0.5	0.0001	0.00001												
GVB1	New	0.36	0.015	0.0019	0.36	0.015	0.0019	133.2	0.015	0.0019	0.06	0.0076	525.6	0.060	0.0076	0.17	0.0212				3.40E-05	4.28E-06
GVB2	New	0.36	0.015	0.0019	0.36	0.015	0.0019	133.2	0.015	0.0019	0.06	0.0076	525.6	0.060	0.0076	0.17	0.0212				3.40E-05	4.28E-06
GVB4	New	0.36	0.015	0.0019	0.36	0.015	0.0019	133.2	0.015	0.0019	0.06	0.0076	525.6	0.060	0.0076	0.17	0.0212				3.40E-05	4.28E-06
GVB5	New	0.36	0.015	0.0019	0.36	0.015	0.0019	133.2	0.015	0.0019	0.06	0.0076	525.6	0.060	0.0076	0.17	0.0212				3.40E-05	4.28E-06
KB1	New	3.23	0.135	0.0169	3.23	0.135	0.0169	798.0	0.091	0.0115	0.65	0.0825	3885.0	0.443	0.0559	4.02	0.5062				3.01E-04	3.79E-05
KB2	New	3.23	0.135	0.0169	3.23	0.135	0.0169	798.0	0.091	0.0115	0.65	0.0825	3885.0	0.443	0.0559	4.02	0.5062				3.01E-04	3.79E-05
KB3	New	3.23	0.135	0.0169	3.23	0.135	0.0169	798.0	0.091	0.0115	0.65	0.0825	3885.0	0.443	0.0559	4.02	0.5062				3.01E-04	3.79E-05
KB4	New	3.23	0.135	0.0169	3.23	0.135	0.0169	798.0	0.091	0.0115	0.65	0.0825	3885.0	0.443	0.0559	4.02	0.5062				3.01E-04	3.79E-05
MAU1	New	0.40	0.017	0.0021	0.40	0.017	0.0021	145.7	0.017	0.0021	0.22	0.0276	1916.7	0.219	0.0276	0.18	0.0232				3.72E-05	4.69E-06
MAU2	New	0.40	0.017	0.0021	0.40	0.017	0.0021	145.7	0.017	0.0021	0.22	0.0276	1916.7	0.219	0.0276	0.18	0.0232				3.72E-05	4.69E-06
NMSBC1F	New	0.72	0.030	0.0038	0.12	0.005	0.0006	4.7	0.001	0.0001												
NMSBC2F	New	0.72	0.030	0.0038	0.12	0.005	0.0006	4.7	0.001	0.0001												
KS1	New	1.41	0.059	0.0074	1.41	0.059	0.0074	220.4	0.025	0.0032	0.29	0.0361	1073.0	0.122	0.0154	1.76	0.2215				1.32E-04	1.66E-05
KS2	New	5.65	0.235	0.0297	5.65	0.235	0.0297	881.6	0.101	0.0127	1.15	0.1444	4292.0	0.490	0.0617	7.03	0.8861				5.27E-04	6.64E-05
KS3	New	1.41	0.059	0.0074	1.41	0.059	0.0074	220.4	0.025	0.0032	0.29	0.0361	1073.0	0.122	0.0154	1.76	0.2215				1.32E-04	1.66E-05
KS4	New	4.24	0.177	0.0222	4.24	0.177	0.0222	661.2	0.075	0.0095	0.86	0.1083	3219.0	0.367	0.0463	5.27	0.6646				3.95E-04	4.98E-05
KS5	New	1.41	0.059	0.0074	1.41	0.059	0.0074	220.4	0.025	0.0032	0.29	0.0361	1073.0	0.122	0.0154	1.76	0.2215				1.32E-04	1.66E-05
EG1	Existing	3.17	0.132	0.0166	3.17	0.132	0.0166	13.2	0.002	0.0002	**	**	186.0	0.021	0.0027	0.40	0.0505					
BH1	Existing	1.80	0.075	0.0095	0.30	0.012	0.0016	22.6	0.003	0.0003												
BH2	Existing	3.58	0.149	0.0188	0.28	0.012	0.0015	27.5	0.003	0.0004												
BH3	Existing	2.41	0.100	0.0126	0.34	0.014	0.0018	8.3	0.001	0.0001												
KSE01	Existing	6.85	0.285	0.0360	4.33	0.181	0.0227	1401.8	0.160	0.0202												
KSE02	Existing	6.85	0.285	0.0360	4.33	0.181	0.0227	1401.8	0.160	0.0202												
KSE03	Existing	6.85	0.285	0.0360	4.33	0.181	0.0227	1401.8	0.160	0.0202												
KSE04	Existing	6.85	0.285	0.0360	4.33	0.181	0.0227	1401.8	0.160	0.0202												
KSE05	Existing	6.85	0.285	0.0360	4.33	0.181	0.0227	1401.8	0.160	0.0202												
CS	Existing	8.71	0.363	0.0457	8.71	0.363	0.0457	1960.2	0.224	0.0282												
BS1	Existing	1.14	0.048	0.0060	1.14	0.048	0.0060	159.9	0.018	0.0023	0.63	0.0787	2103.6	0.240	0.0303	0.53	0.0661					
BS2	Existing	0.46	0.019	0.0024	0.46	0.019	0.0024	166.4	0.019	0.0024	0.25	0.0315	2190.0	0.250	0.0315	0.21	0.0265					
TB	Existing	33.31	1.388	0.1749	5.69	0.237	0.0299	183.8	0.021	0.0026												
RB1	Existing	6.06	0.253	0.0318	1.05	0.044	0.0055	66.3	0.008	0.0010												
RB2	Existing	6.06	0.253	0.0318	1.05	0.044	0.0055	66.3	0.008	0.0010												
New sources: total g/sec emissions for SIA modeling				0.4156			0.3033			0.2159		0.7765			0.4632		4.3712			0.0677		3.443E-04
All sources: total g/sec emissions for NAAQS				0.9455			0.5336			0.3552		0.8868			0.5277		4.5143			---		---

Blue is input value, black is calculated value.

* Emissions for the GV1-GV4 sources occur over a two hour period once a day. Chlorine is emitted a maximum for 2 hours/day from two GV stacks.
For example, if considering the GV1 source, the daily chlorine emissions of 12.9 lb/day for GV1 were distributed evenly amongst two release points, GV1A, and GV2A during a given day.
This allocation was performed for all GV1-4 sources (i.e., using GV1A/GV1B, GV2A/GV2B, etc. combinations) and the highest impacts from modeling were determined for each of the release combinations.

** NOx emissions from the emergency generator were not included in the 1-hour NO_2 analyses.

Appendix F – GWM Stack Temperature and Flow Rate Documentation

Great Western Malting Expansion- Stack Exhaust Flow Rates

Stack ID	Equipment ID	Equipment Name	Exhaust Temp °F	Exhaust Air flow Rates Volume	Units	Air Flow Basis
Existing Stacks						
BH1	BH1	Baghouse 1	Ambient	29,900	ACFM	Axelson Enginering specs
BH2	BH2	Baghouse 2	Ambient	45,150	ACFM	Axelson Enginering specs
BH3	BH3	Baghouse 3	Ambient	43,600	ACFM	Axelson Enginering specs
KSE	K1	Kiln 1 exhaust	79	529,800	ACFM	Source Test 10/14/2005
KS1	K1	Kiln 1 heater 1	130	2,263	ACFM	combustion calculation basis at 7.9 MM Btuh
KS2	K2-K5	Kiln 1 heaters 2-5	130	9,052	ACFM	combustion calculation basis at 31.6 MM Btuh
KS3	K6	Kiln 1 heater 6	130	2,263	ACFM	combustion calculation basis at 7.9 MM Btuh
KS4	K7-K9	Kiln 1 heaters 7-9	130	6,789	ACFM	combustion calculation basis at 23.7 MM Btuh
KS5	K10	Kiln 1 heater 10	130	2,263	ACFM	combustion calculation basis at 7.9 MM Btuh
GBE 1-3	each stack	Germination Beds 1-3	70	52,000	ACFM	Germination bed design
GBE 4-6	each stack	Germination Beds 4-6	70	52,000	ACFM	Germination bed design
CS	CS	Pellet Cooler Stack	132	8,330	ACFM	Source Test 4/27/2000
BS1	BS1	Malt House boilers 1 & 2	350	2,460	ACFM	combustion calculation basis at 6.25 MM Btuh
BS2	BS2	Pellet Mill boiler	400	1,045	ACFM	combustion calculation at 2.5 MM Btuh
TB	TB	Truck Bay	NA	NA	ACFM	fugitive
RB	RB	Rail Bay	NA	NA	ACFM	fugitive
EG	EG1	Emergency Generator	600	400	ACFM	engine information
Expansion Stacks						
S1	STC1F	Steep Tank Fill Conveyor 1 Filter	Ambient	285	ACFM	Product air displacement and 1.5 safety factor
S2	STC2F	Steep Tank Fill Conveyor 2 Filter	Ambient	285	ACFM	Product air displacement and 1.5 safety factor
S3	STA1	Exhaust for steep A/1	Ambient	2,940	SCFM	CO2 emissions, did not model
S4	STA2	Exhaust for steep A/2	Ambient	2,940	SCFM	CO2 emissions, did not model
S5	STA3	Exhaust for steep A/3	Ambient	2,940	SCFM	CO2 emissions, did not model
S6	STA4	Exhaust for steep A/4	Ambient	2,940	SCFM	CO2 emissions, did not model
S7	STA5	Exhaust for steep A/5	Ambient	2,940	SCFM	CO2 emissions, did not model
S8	STA6	Exhaust for steep A/6	Ambient	2,940	SCFM	CO2 emissions, did not model
S9	STA7	Exhaust for steep A/7	Ambient	2,940	SCFM	CO2 emissions, did not model
S10	STA8	Exhaust for steep A/8	Ambient	2,940	SCFM	CO2 emissions, did not model
S11	STB1	Exhaust for steep B/1	Ambient	2,940	SCFM	CO2 emissions, did not model
S12	STB2	Exhaust for steep B/2	Ambient	2,940	SCFM	CO2 emissions, did not model
S13	STB3	Exhaust for steep B/3	Ambient	2,940	SCFM	CO2 emissions, did not model
S14	STB4	Exhaust for steep B/4	Ambient	2,940	SCFM	CO2 emissions, did not model
S15	STB5	Exhaust for steep B/5	Ambient	2,940	SCFM	CO2 emissions, did not model
S16	STB6	Exhaust for steep B/6	Ambient	2,940	SCFM	CO2 emissions, did not model
S17	STB7	Exhaust for steep B/7	Ambient	2,940	SCFM	CO2 emissions, did not model
S18	STB8	Exhaust for steep B/8	Ambient	2,940	SCFM	CO2 emissions, did not model
S19-S20	GV1	Germination Vessel 1 (GV1)	Ambient			modeled as volume source
S21-S22	GV2	Germination Vessel 2 (GV2)	Ambient			modeled as volume source
S23-S24	GV3	Germination Vessel 3 (GV3)	Ambient			modeled as volume source
S25-S26	GV4	Germination Vessel 4 (GV4)	Ambient			modeled as volume source
S27	KB1	Kiln 2 Air Heater Burner 1	130	4,660	SCFM	combustion calculation basis at 18.15 MM Btuh
S28	KB2	Kiln 2 Air Heater Burner 2	130	4,660	SCFM	combustion calculation basis at 18.15 MM Btuh
S29	KB3	Kiln 2 Air Heater Burner 3	130	4,660	SCFM	combustion calculation basis at 18.15 MM Btuh
S30	KB4	Kiln 2 Air Heater Burner 4	130	4,660	SCFM	combustion calculation basis at 18.15 MM Btuh
S31	K2	Kiln 2 exhaust	100	859,795	SCFM	Capacity of 2 fans, each at 830,000 m3/hr
S32	NMLF	Kiln New Malt Leg Filter	Ambient	1,500	ACFM	Product air displacement and 1.5 safety factor
S33	BA1F	Malt Analysis Bin 1 Fill Filter	Ambient	390	ACFM	Product air displacement and 1.5 safety factor
S34	BA2F	Malt Analysis Bin 2 Fill Filter	Ambient	390	ACFM	Product air displacement and 1.5 safety factor
S35	KBPCF	Kiln Byproduct Cyclone Filter	Ambient	390	ACFM	Product air displacement and 1.5 safety factor
S36	NMC3F	New Malt Conveyor 3 Filter	Ambient	285	ACFM	Product air displacement and 1.5 safety factor
S37	MBCF	Micro Bins Fill Conveyor Filter	Ambient	97.5	ACFM	Product air displacement and 1.5 safety factor
S38	GVB1	Germination Vessel Boiler 1	200	510	SCFM	combustion calculation basis at 2 MM Btuh
S39	GVB2	Germination Vessel Boiler 2	200	510	SCFM	combustion calculation basis at 2 MM Btuh
S40	GVB3	Germination Vessel Boiler 3	200	510	SCFM	combustion calculation basis at 2 MM Btuh
S41	GVB4	Germination Vessel Boiler 4	200	510	SCFM	combustion calculation basis at 2 MM Btuh
S42	GVB5	Germination Vessel Boiler 5	200	510	SCFM	combustion calculation basis at 2 MM Btuh
S43	GVB6	Germination Vessel Boiler 6	200	510	SCFM	combustion calculation basis at 2 MM Btuh
S44	MAU1	Make Up Air Unit 1	200	481	SCFM	combustion calculation basisat 2.18 MM Btuh
S45	MAU2	Make Up Air Unit 2	200	481	SCFM	combustion calculation basisat 2.18 MM Btuh
S46	NMSBC1F	New Malt Storage Bins 1-5 Conveyor 1 Filter	Ambient	285	ACFM	Product air displacement and 1.5 safety factor
S47	NMSBC2F	New Malt Storage Bins 6-10 Conveyor 2 Filter	Ambient	285	ACFM	Product air displacement and 1.5 safety factor

Great Western Malting Expansion
Stack Exhaust Flow Rates

1. Existing Kiln (K1) Stack ID: KSE

Flow rate from 10/14/2005 source test = 503,920 dscfm at 3% moisture + 79 °F (539 °R)

$$503{,}920 \text{ dscfm} \times \frac{1.03 \text{ wet}}{\text{dry}} \times \frac{539 \text{ actual}}{528 \text{ std}} = \underline{529{,}851 \text{ acfm}}$$

(use 529,800 acfm)

2. Existing Kiln Burners Stack ID: KS1 to KS5

10 burners each @ 6.9 MMBtu/hr heat input

$$\text{Natural Gas input} = 6.9 \frac{\text{MMBtu}}{\text{hr}} \times \frac{1 \text{ hr}}{60 \text{ min}} \times \frac{1 \text{ scf}}{1020 \text{ Btu}} = 112.7 \frac{\text{scf}}{\text{min}} \text{ fuel}$$

Air flow @ 30% excess air = 240 scfm per MMBtuh

$$240 \frac{\text{scfm}}{\text{MMBtuh}} \times 6.9 \text{ MMBtuh} = 1656 \text{ scf}$$

Actual exhaust temp = 150 °F (610 °R)

$$\text{Actual Air flow per burner} = (112.7 + 1656) \text{ scfm} \times \frac{610}{528} = 2046 \text{ acfm}$$

Stack KS1 = 1 burner exhaust = <u>2046 acfm</u>

Stack KS2 = 4 burner exhausts = 2046 × 4 = <u>8184 acfm</u>

Stack KS3 = 1 burner exhaust = <u>2046 acfm</u>

Stack KS4 = 3 burner exhaust = 2046 × 3 = <u>6,138 acfm</u>

Stack KS5 = 1 burner exhaust = <u>2046 acfm</u>

3. Pellet Cooler Cyclone Stack ID: CS

Flowrate from 4/27/2000 source test = 7330 dscfm at 1.4% moisture + 132 °F (592 °R)

$$7330 \text{ dscfm} \times \frac{1.014 \text{ wet}}{\text{dry}} \times \frac{592 \text{ actual}}{528 \text{ std}} = \underline{8334 \text{ acfm}}$$

(use 8330 acfm)

4. Existing Malthouse Boilers   Stack ID: BS1

Limit heat input to 6.25 MMBtu/hr

Natural gas input = $6.25 \frac{MMBtu}{hr} \times \frac{1\,hr}{60\,min} \times \frac{1\,scf}{1020\,Btu}$ = 102 scfm fuel

Air flow @ 30% excess air = 240 scfm per MMBtuh

$240 \frac{scfm}{MMBtuh} \times 6.25\ MMBtuh = 1500\ scfm$

Actual exhaust temp = 350 °F (810 °R)

Actual exhaust flow = $(1500 + 102)\,scfm \times \frac{810\,T}{528\,T}$ ≐ <u>2458 acfm</u>
(use 2460 acfm)

5. Pellet Mill Boiler   Stack ID: BS2

Boiler burner = 2.5 MMBtu/hr

Natural Gas input = $2.5 \frac{MMBtu}{hr} \times \frac{1\,hr}{60\,min} \times \frac{1\,scf}{1020\,Btu}$ = 41 scfm fuel

Air Flow @ 30% excess air

$240 \frac{scfm}{MMBtuh} \times 2.5\ Btuh$ ≐ 600 scfm

Total exhaust flow @ 400 °F (860 °R)

$(600 + 41)\,scfm \times \frac{860\ actual\ T}{528\ std\ T}$ = <u>1045 acfm</u>

6. New Kiln (K2)   Stack ID: S31

Kiln will have 2 fans each rated at $830{,}000 \frac{m^3}{hr}$ @ 60°C

$830{,}000 \frac{m^3}{hr\text{-}fan} \times 2 \times \frac{1\,hr}{60\,min} \times 35.3147 \frac{cf}{m^3}$ = 977,040 acfm @ 140°F

$977{,}040\ acfm \times \frac{(528\ °R)}{(460+140)}$ = <u>859,795 scfm</u>

7. Kiln Heaters   Stack ID: S27 - S30

4 heaters each w/ 18.15 MMBtuh burner   1 stack per heater

Natural gas: $18.15 \frac{MMBtu}{hr} \times \frac{1}{60 min} \times \frac{1 scf}{1020 Btu} = 300$ scfm per heater

Air flow @ 30% excess air

$240 \frac{scfm}{MMBtuh} \times 18.15 = 4356$ scfm per heater stack

Total Exhaust air flow per each stack = 4356 scfm + 300 scfm = 4656 scfm (use 4660 scfm)

8. Germination Vessel Boilers   Stack ID: S38 - S43

6 boilers each with 2 MMBtu/hr burner   1 stack per boiler

Natural gas: $2 \frac{MMBtu}{hr} \times \frac{1 hr}{60 min} \times \frac{1 scf}{1020} = 30$ scfm

Air flow @ 30% excess air

$240 \frac{scfm}{MMBtuh} \times 2$ MMBtuh = 480 scfm

Total exhaust flow = 480 scfm + 30 scfm = 510 scfm per boiler stack

9. Makeup Air Units (MAU)   Stack ID: S44 + S45

2 MAUs each with 2.18 MMBtuh burners

Natural gas input = $2.18 \frac{MMBtu}{hr} \times \frac{1 hr}{60 min} \times \frac{1 cf}{1020 Btu} \doteq 36$ scfm

Air flow @ 10% excess air

$204 \frac{scfm}{MMBtuh} \times 2.18$ MMBtuh $\doteq 445$ scfm

Total exhaust air flow = 445 scfm + 36 scfm = 481 scfm per stack

10. New Dust Filters

The exhaust air flow rates for the dust filters are based on the quantity of air displaced by the product (grain or malt) moving through the equipment times a 1.5 safety factor.

Resulting stack flows are:

Stack ID	Displaced Air Volume (acfm)	Air Volume x 1.5 (acfm)
S1	190	285
S2	190	285
S32	1000	1500
S33	260	390
S34	260	390
S35	260	390
S36	190	285
S37	65	97.5
S46	190	285
S47	190	285

Stack Exhaust Flow Rates (cont.)

11. Kiln 1 Heaters   Stack ID: KS1-KS5

10 heaters each w/ 7.9 MM Btuh burner

Natural gas: $7.9 \frac{MMBtu}{hr} \times \frac{1\,hr}{60\,min} \times \frac{1\,scf}{1020\,Btu} = 129$ scfm per heater

Air flow @ 30% excess air:

$240 \frac{scfm}{MM\,Btuh} \times 7.9\,MMBtuh = 1896$ scfm per heater

Total Exhaust flow per heater = 129 + 1896 = 2025 scfm

acfm @ 130°F = $2025\,scfm \times \frac{590\,°R}{528\,°R} = 2263$ acfm

Stack KS1 = 1 heater exhaust = 2263 acfm

Stack KS2 = 4 heaters exhaust = 4 × 2263 = 9052 acfm

Stack KS3 = 1 heater exhaust = 2263 acfm

Stack KS4 = 3 heaters exhaust = 3 × 2263 = 6789 acfm

Stack KS5 = 1 heater exhaust = 2263 acfm

Dust Fan #1

Equipment No. 115 Receiving and Shipping Filter #1 - Bag type dust filter as manufactured by CEA Carter-Day Company, 500 73rd Avenue N.E., Minneapolis, Minnesota 55432 (phone 612-571-1000) or approved equal and specified as follows:

Size 232RF10 with walk-in type roof cover to remove bags.
Dacron filter bags, 15 oz/sq ft, felt, rated 99.95% efficiency with grain dust. - bags replaced with Donaldson Dura-~~Plus~~ Life style bags in 2010
Effective bag filter area 2960 ft^2.
Approximate air to cloth ratio - 10.10/1 (grain dust).
Steel housing.
Hopper, steel cone 60° slope from horizontal with Van Stone discharge flange to match 12" airlock #117, 24" diameter manhole, sight port near bottom of cone.
Separate inlet scroll for orienting either clockwise or counterclockwise.
Separate cone deflector at inlet scroll.
Standard gage steel construction, weathertite.
Paint manufacturer's standard.
Three rupture membranes 36" square located on bag section housing.
Backwash manifold with 1/3 horsepower gearmotor drive TEFC, 230/460/3/60.
Air reservior and diaphragm valve (110/1/60), electric timer 110/1/60.
Backwash blower, five horsepower motor drive 230/460/3/60 TEFC complete with pressure gage, relief valve, intake filter-muffler complete except for pipe between blower and air reservior.
Magnehelic gage with copper tube and fittings for remote reading of pressure drop across filter and located approximately 50 feet from filter.
Service ladder and handrail, height to be determined later.
Support frame and legs of height to be determined later. Final support frame must be satisfactory to withstand wind load at 40 feet above grade and seismic zone 3 for Pocatello, Idaho.
Estimated drop across filter bags under operation described is 2"-3" W.G.
Orientation of inlet outlet, air reservior and ladder to be determined later.
Manufacturer to furnish standard arrangement drawing showing increments of bolt holes in body rings, flange dimensions and bolt holes all for marking-up for orientation prior to fabrication. Five sets of final drawings, installation-operating and maintenance manuals shall be furnished to purchaser for distribution.

Rev. 4/23/80
Rev. 6/6/80

Dust Fan #1

#1

Equipment No. 116 Receiving and Shipping Filter Fan-Backward -

Inclined blade fan as manufactured by Twin City Fan and Blower Company, 550 Kasota Avenue S.E., Minneapolis, Minnesota 55414 (phone 612-331-4104) or approved equal and per following specifications:

Size 365BC, class IV service.
Arrangement #1, rotation CWTAD.
Rated 29900 cfm @ 15" S.P.
V-belt drive and guard for 1722 rpm and 100.40 bhp.
Motor slide base for motor location at motor position Z.
Inlet flange.
Outlet flange.
Access door.
Bottom drain.
Vibration isolators.
Shaft guard.
Paint manufacturer's standard.
Manufacturer shall submit drawings for approval prior to fabrication.
Manufacturer shall furnish five sets of final drawings, installation-operating and maintenance manuals to purchaser for distribution.

Drive motor, 125 horsepower, frame 444T, TEFC, 460/3/60, Nema 'C', SF 1.15 rated for V-belt drive on fan with OSHA belt guard.

Final operating speed may require adjustment to balance system under operating conditions. This would involve changing one or both sheaves.

Belt drive:

1- Motor sheave, 10GR, 5V9.00, bushed for 3 3/8" shaft x 7/8" K.W. x 4 11/32 face.

1- Fan sheave, 10GR, 5V9.25, bushed for 3 7/16" shaft x 7/8" K.W. x 4 11/32 face.

10- Belts, 5V1400, matched for 55.7" shaft centers.

1- Belt guard, expanded metal, split and hinged, OSHA standard. Paint same as fan.

1- Motor slide base, FR444T.

Rev. 2/18/80
Rev. 4/23/80
Rev. 6/6/80

Dust Fan #2

Equipment No. 120 Barley Cleaning and Distribution Filter -

Bag type dust filter as manufactured by CEA Carter-Day Company or approved equal and as specified below:

Size 376RF10 with walk-in type roof cover to remove bags.
Dacron filter bags, 15 oz/sq ft, felt, rated 99.95% efficiency with grain dust. Dura ~~Flus~~ Life bags installed 10/14/15
Effective bag filter area 4800 ft^2.
Approximate air to cloth ratio - 9.41/1 (grain dust).
Steel housing.
Hopper, steel cone 60^o slope from horizontal with Van Stone discharge flange to match 12" airlock #117, 24" diameter manhole, sight port near bottom of cone.
Separate inlet scroll for orienting either clockwise or counterclockwise.
Separate cone deflector at inlet scroll.
Standard gage steel construction, weathertite.
Paint manufacturer's standard.
Three rupture membranes 36" square located on bag section housing.
Backwash manifold with 1/3 horsepower gearmotor drive TEFC, 230/460/3/60.
Air reservior and diaphragm valve (110/1/60), electric timer 110/1/60.
Backwash blower, five horsepower motor drive 230/460/3/60 TEFC complete with pressure gage, relief valve, intake filter-muffler complete except for pipe between blower and air reservior.
Magnehelic gage with copper tube and fittings for remote reading of pressure drop across filter and located approximately 50 feet from filter.
Service ladder and handrail, height to be determined later.
Support frame and legs of height to be determined later. Final support frame must be satisfactory to withstand wind load at 40 feet above grade and seismic zone 3 for Pocatello, Idaho.
Estimated drop across filter bags under operation described is 2"-3" W.G.
Orientation of inlet outlet, air reservior and ladder to be determined later.
Manufacturer to furnish standard arrangement drawing showing increments of bolt holes in body rings, flange dimensions and bolt holes all for marking-up for orientation prior to fabrication. Five sets of final drawings, installation-operating and maintenance manuals shall be furnished to purchaser for distribution.

backwash 13427-11
filter 13427-7

Rev. 4/23/80
Rev. 6/6/80

Dust Fan #205B

Equipment No. 121 Barley Cleaning and Distribution Filter Fan -

As manufactured by Twin City Fan and Blower Company or approved equal and as specified below:

Size 445BC, class IV service.
Arrangement #1, rotation CWTAD.
Rated 45150 cfm @ 13.7" S.P.
V-belt drive and guard for 1392 rpm and 141.49 bhp.
Motor slide base for motor position Z.
Inlet flange.
Outlet flange.
Access door.
Bottom drain.
Vibration isolators.
Shaft guard.
Paint manufacturer's standard.
Manufacturer shall submit drawings for approval prior to fabrication. Manufacturer shall furnish five sets of final drawings, installation-operating and maintenance manuals for distribution.

Drive motor, 150 horsepower, 1800 rpm, frame 445T, TEFC, Nema 'C', SF 1.15 230/460/3/60, rated for V-belt drive on fan.

Final operating speed may require adjustment to balance system under operating conditions. This would involve changing one or both sheaves.

Belt drive:

1- Motor sheave, 8GR-5V11.8, bushed for 3 3/8" shaft x 7/8" K.W. x 3 17/32" face.

1- Fan sheave, 8GR-5V15.0, bushed for 3 15/16" shaft x 1" K.W. x 3 17/32" face.

8- Belts, 5V1600, matched for 58.9" shaft centers.

1- Belt guard, expanded metal, split and hinged, OSHA standard. Paint same as fan.

1- Motor slide base, FR445T.

Wire equipment numbers 120, 121, 122 and 123 as follows:

Start all above with one start button used in conjunction with time delay relays so as to start airlock #122 and screw conveyor #123 first, filter #120 second and fan #120 last. Start will be interlocked to high level devices in bins BD1 and BD2 thru set-up of limit switches on two way valve feeding either bin. If bin to be filled indicated "full", system cannot start.

Stop all above motors with one stop button used in conjunction with time delay relays so as to stop fan #121 immediately, stop filter #120 (three minutes after initiating stop button) and stop airlock-screw conveyor #122 and 123 (two minutes after filter #120 stops). Solenoid valve circuit (110V) on equipment #120 to operate when equipment #120 operates.

All motors shall have running lights with one common start-stop button located in first floor office of workhouse.

Great Western Malting- Axelson Equipment Specifications
Baghouse 3 (BH3)

Rev. 2/18/80
Rev. 4/23/80

Dust Fan #3

Equipment No. 124 Malt Cleaning System Filter - Bag type dust filter

as manufactured by CEA Carter-Day Company or approved equal and as specified below:

One size 376RF10 filter same specifications as for Equipment #~~102~~ 120, A/C ratio 9.08/1.

Backwasher 13427-11
filter 13427-7

Dura Life bags installed

Dust Fan #3 #3

Equipment No. 125 Malt Cleaning Filter Fan - As manufactured by Twin City Fan and Blower Company, 550 Kasota Avenue S.E., Minneapolis, Minnesota 55414 (phone 612-331-4104) representative David P. Wilson Company, Portland, Oregon 97221 (phone 503-292-2488, Mr. Day Tooley) or approved equal and as specified below:

Size 445BC, class IV service.
Arrangement #1, rotation CCWTAD.
Rated 43600 cfm @ 14" S.P.
V-belt drive and guard for 1382 rpm and 128.45 bhp.
Motor slide base for motor position W.
Inlet flange.
Outlet flange.
Access door.
Bottom drain.
Vibration isolators.
Shaft guard.
Paint manufacturer's standard.
Manufacturer shall submit drawing for approval prior to fabrication. Manufacturer shall furnish five sets of final drawings, installation-operating and maintenance manuals for distribution.

Drive motor, 150 horsepower, 1800 rpm, frame 445T, TEFC, Nema 'C', S.F. 1.15 230/460/3/60 rated for V-belt drive on fan.

Final operating speed may require adjustment to balance system under operating conditions. This would involve changing one or both sheaves.

Belt drive:

1- Motor sheave, 8GR-5V11.8, bushed for 3 3/8" shaft x 7/8" K.W. x 3 17/32" face.

1- Fan sheave, 8GR-5V15.0, bushed for 3 15/16" shaft x 1" K.W. x 3 17/32" face.

8- Belts, 5V1600 matched for 58.9" shaft centers.

1- Belt guard, expanded metal, split and hinged, OSHA standard. Paint same as fan.

1- Motor slide base, FR445T.

Appendix G – DEQ PTC Modeling Forms (MI1 - MI4)

DEQ AIR QUALITY PROGRAM
1410 N. Hilton, Boise, ID 83706
For assistance, call the
Air Permit Hotline - 1-877-5PERMIT

PERMIT TO CONSTRUCT APPLICATION

Revision 3
4/5/2007

Please see instructions on page 2 before filling out the form.

Company Name:	Great Weatern Malting Company
Facility Name:	Great Weatern Malting Company, Pocatello
Facility ID No.:	005-00035
Brief Project Description:	Production of Barley Malt and Barley Feed (Some of Which is Pelletized)

SUMMARY OF AIR IMPACT ANALYSIS RESULTS - CRITERIA POLLUTANTS

		1.		2.	3.	4.		5.
Criteria Pollutants	**Averaging Period**	**Significant Impact Analysis Results (µg/m3)**	**Significant Contribution Level (µg/m3)**	**Full Impact Analysis Results (µg/m3)**	**Background Concentration (µg/m3)**	**Total Ambient Impact (µg/m3)**	**NAAQS (µg/m3)**	**Percent of NAAQS**
$PM_{2.5}$	24-hour	8.0	1.2	21.8	12.0	33.8	35	97%
	Annual	2.0	0.3	6.2	4.3	10.5	12	88%
PM_{10}	24-hour	11.9	5	69.2	72.0	141.2	150	94%
NO_2	1-hour	122.8	7.5	109.2	60.2	169.4	188	90%
	Annual	7.6	1	8.9	9.0	17.9	100	18%
SO_2	1-hour	N/A	7.8	N/A	N/A	N/A		N/A
	3-hour	N/A	25	N/A	N/A	N/A		N/A
	24-hour	N/A	5	N/A	N/A	N/A		N/A
	Annual	N/A	1	N/A	N/A	N/A		N/A
CO	1-hour	2,179.1	2,000	1,964.8	3,306.0	5,270.8	40,000	13%
	8-hour	459.5	500	351.6	1,118.0	1,469.6	10,000	15%

Instructions for Form MI1

This form is designed to provide the air quality modeler with a summary of the air impact analysis results for the criteria pollutants. This information will be used by IDEQ to determine compliance demonstration with the national ambient air quality standards (NAAQS).

Please fill in the same company name, facility name, facility ID number, and brief project description as on Form CS in the boxes provided. This is useful in case any pages of the application get separated.

Significant Impact Analysis - Evaluates the emissions increase from the proposed project only. This analysis determines whether or not a proposed project has a significant impact on ambient air, and therefore, requires a full impact analysis.

Full Impact Analysis - Only required if the significant impact analysis exceeds the significant contribution level - evaluates the emissions from the facility, including the emissions increase from the proposed project. This analysis determines whether the facility, with the emissions increase, complies with the NAAQS.

1. Provide the results of the significant impact analysis in $\mu g/m^3$.
2. Provide the results of the full impact analysis in $\mu g/m^3$ (if required).
3. List the background concentration in mg/m3. Contact the Stationary Source Modeling Coordinator at (208) 373-0502 for the current background concentrations for the area of interest. (Not needed if full impact analysis is not required.)
4. Provide the total ambient impact in mg/m3. The total ambient impact is the sum of the background concentration and the full impact analysis result.
5. Calculate the percent of the NAAQS that the total ambient impact analysis represents.

DEQ AIR QUALITY PROGRAM 1410 N. Hilton, Boise, ID 83706 For assistance, call the **Air Permit Hotline - 1-877-5PERMIT**	**PERMIT TO CONSTRUCT APPLICATION** Revision 3 3/27/2007

Please see instructions on page 2 before filling out the form.

Company Name:	Great Western Malting Company
Facility Name:	Great Western Malting Company, Pocatello
Facility ID No.:	005-00035
Brief Project Description:	Production of Barley Malt and Barley Feed (Some of Which is Pelletized)

POINT SOURCE STACK PARAMETERS

1.	2.	3a.	3b.	4.	5.	6.	7.	8.	9.	10.
Emissions units	**Stack ID**	**UTM Easting (m)**	**UTM Northing (m)**	**Base Elevation (m)**	**Stack Height (m)**	**Modeled Diameter (m)**	**Stack Exit Temperature (K)**	**Stack Exit Flowrate (acfm)**	**Stack Exit Velocity (m/s)**	**Stack orientation (e.g., horizontal, rain cap)**
Point Source(s)										
Spot Filter - Barley to Steeps	STC1F	378,450.29	4,750,026.78	1,350.26	26.37	0.25	AMBIENT	285	2.65	VERTICAL
Spot Filter - Above Steeps	STC2F	378,444.30	4,750,022.00	1,350.26	28.19	0.25	AMBIENT	285	2.65	VERTICAL
Kiln Air Heater 1 Burner Stack	KB1	378,381.28	4,750,105.42	1,350.26	21.34	0.61	327.59	6,136	9.92	VERTICAL
Kiln Air Heater 2 Burner Stack	KB2	378,388.24	4,750,100.71	1,350.26	21.34	0.61	327.59	6,136	9.92	VERTICAL
Kiln Air Heater 3 Burner Stack	KB3	378,398.05	4,750,094.07	1,350.26	21.34	0.61	327.59	6,136	9.92	VERTICAL
Kiln Air Heater 4 Burner Stack	KB4	378,405.26	4,750,089.18	1,350.26	21.34	0.61	327.59	6,136	9.92	VERTICAL
Kiln 2 Exhaust	K2	378,387.26	4,750,084.49	1,350.26	20.42	13.92	310.93	1,074,468	3.33	VERTICAL
Spot Filter - Analysis Bins Elevator	NMLF	378,399.58	4,750,054.38	1,350.26	1.83	0.25	AMBIENT	1,500	13.97	VERTICAL
Spot Filter - Analysis Bin W	BA1F	378,408.38	4,750,055.52	1,350.26	24.38	0.25	AMBIENT	390	3.63	VERTICAL
Spot Filter - Analysis Bin E	BA2F	378,415.79	4,750,050.36	1,350.26	24.38	0.25	AMBIENT	390	3.63	VERTICAL
Spot Filter - Byproduct Cyclone	KBPCF	378,475.12	4,750,057.65	1,350.26	27.43	0.25	AMBIENT	390	3.63	VERTICAL
Spot Filter - Kiln Tunnel	NMC3F	378,458.00	4,750,022.00	1,350.26	2.74	0.25	AMBIENT	285	2.65	VERTICAL
Spot Filter - Micro Bin	MBCF	378,464.68	4,750,084.17	1,350.26	15.24	0.25	AMBIENT	98	0.91	VERTICAL
Germination Vessel Boiler 1	GVB1	378,366.15	4,750,028.81	1,350.26	6.10	0.15	366.48	751	19.44	VERTICAL
Germination Vessel Boiler 2	GVB2	378,370.17	4,750,026.04	1,350.26	6.10	0.15	366.48	751	19.44	VERTICAL
Germination Vessel Boiler 4	GVB4	378,480.90	4,749,950.07	1,350.26	6.10	0.15	366.48	751	19.44	VERTICAL
Germination Vessel Boiler 5	GVB5	378,484.67	4,749,947.43	1,350.26	6.10	0.15	366.48	751	19.44	VERTICAL
Make Up Air Unit 1	MAU1	378,450.23	4,750,015.99	1,350.26	1.83	0.20	366.48	708	10.31	VERTICAL
Make Up Air Unit 2	MAU2	378,405.49	4,749,978.03	1,350.26	1.83	0.20	366.48	708	10.31	VERTICAL
New Malt Storage Bins 1-5 Conveyor	NMSBC1F	378,453.75	4,750,117.67	1,350.26	27.43	0.25	AMBIENT	285	2.65	VERTICAL
New Malt Storage Bins 6-10 Conveyo	NMSBC2F	378,447.46	4,750,108.62	1,350.26	27.43	0.25	AMBIENT	285	2.65	VERTICAL
Kiln 1 Burner 01	KS1	378,496.20	4,750,045.00	1,350.26	35.97	0.27	327.59	2,263	18.48	VERTICAL
Kiln 1 Burners 02-05	KS2	378,506.60	4,750,039.00	1,350.26	35.97	0.44	327.59	9,052	27.85	VERTICAL
Kiln 1 Burner 06	KS3	378,510.90	4,750,036.00	1,350.26	35.97	0.27	327.59	2,263	18.48	VERTICAL
Kiln 1 Burners 07-09	KS4	378,514.00	4,750,034.00	1,350.26	35.97	0.44	327.59	6,789	20.89	VERTICAL
Kiln 1 Burner 10	KS5	378,524.30	4,750,027.00	1,350.26	35.97	0.27	327.59	2,263	18.48	VERTICAL
Emergency Generator	EG1	378,458.50	4,750,042.00	1,350.26	1.83	0.10	588.71	400	23.29	VERTICAL
Baghouse - Barley Head House	BH1	378,486.00	4,750,063.00	1,350.26	7.92	0.98	AMBIENT	29,900	0.001	HORIZONTAL
Baghouse - Malt & Barely Cleaning	BH2	378,519.00	4,750,068.00	1,350.26	41.15	0.98	AMBIENT	45,150	0.001	HORIZONTAL
Baghouse - Malt Cleaning, Loading &	BH3	378,485.40	4,750,091.00	1,350.26	41.15	0.98	AMBIENT	43,600	0.001	HORIZONTAL
Malt House Boilers Stack	BS1	378,536.20	4,750,015.00	1,350.26	34.14	0.89	449.82	2,460	1.87	VERTICAL
Pellet Mill Boiler Stack	BS2	378,477.60	4,750,069.00	1,350.26	10.36	0.25	477.59	1,045	0.001	HORIZONTAL
Pellet Mill Cooler Stack	CS	378,481.30	4,750,066.00	1,350.26	29.41	0.71	328.71	8,330	9.92	VERTICAL
Kiln 1 Burner 01	KS1	378,496.20	4,750,045.00	1,350.26	35.97	0.27	327.59	2,263	18.48	VERTICAL
Kiln 1 Burners 02-05	KS2	378,506.60	4,750,039.00	1,350.26	35.97	0.44	327.59	9,052	27.85	VERTICAL
Kiln 1 Burner 06	KS3	378,510.90	4,750,036.00	1,350.26	35.97	0.27	327.59	2,263	18.48	VERTICAL
Kiln 1 Burners 07-09	KS4	378,514.00	4,750,034.00	1,350.26	35.97	0.44	327.59	6,789	20.89	VERTICAL
Kiln 1 Burner 10	KS5	378,524.30	4,750,027.00	1,350.26	35.97	0.27	327.59	2,263	18.48	VERTICAL
Kiln 1 Exhaust	KSE01	378,492.70	4,750,052.00	1,350.26	31.70	6.33	299.26	529800*	1.59	VERTICAL
Kiln 1 Exhaust	KSE02	378,503.20	4,750,045.00	1,350.26	31.70	6.33	299.26	529800*	1.59	VERTICAL
Kiln 1 Exhaust	KSE03	378,513.80	4,750,038.00	1,350.26	31.70	6.33	299.26	529800*	1.59	VERTICAL
Kiln 1 Exhaust	KSE04	378,523.80	4,750,032.00	1,350.26	31.70	6.33	299.26	529800*	1.59	VERTICAL
Kiln 1 Exhaust	KSE05	378,534.00	4,750,025.00	1,350.26	31.70	6.33	299.26	529800*	1.59	VERTICAL

* This flowrate represents the total flowrate from the combination of these representative point sources.

Instructions for Form MI2

This form is designed to provide the air quality modeler with information on the stack characteristics of each point source located at the facility. This information may be used by the IDEQ to perform an air quality analysis or to review an air quality analysis submitted with the permit application or requested by the IDEQ.

Please fill in the same company name, facility name, facility ID number, and brief project description as on Form CS in the boxes provided. This is useful in case any pages of the application get separated.

1. Provide the name of the emission unit. This name should match names on other submittals to IDEQ and within this application.
2. Provide the identification number for the stack which the emission unit exits.
3. Provide the UTM locations for each point source. The UTM Easting and UTM Northing are the coordinates for the center of the point source.
4. Provide the elevation of the base of the stack. This elevation must be calculated by the same method as the buildings and receptor elevation.
5. Provide the height of the stack, from the ground.
6. Provide the stack diameter that is included in the modeling analysis. Refer to the State of Idaho Modeling Guideline for guidance on developing the appropriate diameter.
7. Provide the stack exit temperature. Include documentation and justification for the exit temperature used.
8. Provide the stack exit flowrate. Include documentation and justification for the exit flowrate used.
9. Provide the stack exit velocity. Include documentation and justification for the exit velocity used.
10. Provide the orientation of the stack (horizontal or vertical). Indicate whether there is an obstruction on the stack, such as a raincap.

DEQ AIR QUALITY PROGRAM
1410 N. Hilton, Boise, ID 83706
For assistance, call the
Air Permit Hotline - 1-877-5PERMIT

PERMIT TO CONSTRUCT APPLICATION
Revision 3
4/5/2007

Please see instructions on page 2 before filling out the form.

Company Name:	Great Western Malting Company
Facility Name:	Great Western Malting Company, Pocatello
Facility ID No.:	005-00035
Brief Project Description:	Production of Barley Malt and Barley Feed (Some of Which is Pelletized)

FUGITIVE SOURCE PARAMETERS

1.	2.	3a.	3b.	4.	5.	6.	7.	8.	9.	10.
Emissions units	**Stack ID**	**UTM Easting (m)**	**UTM Northing (m)**	**Base Elevation (m)**	**Release Height (m)**	**Easterly Length (m)**	**Northerly Length (m)**	**Angle from North (°)**	**Initial Vertical Dimension (m)**	**Initial Horizontal Dimension (m)**
Volume Source(s)										
Exhaust 1 for GV1	GV1A	378,404.40	4,750,046.69	1,350.26	6.10	15.40	15.40	0	3.58	4.14
Exhaust 2 for GV1	GV1B	378,395.70	4,750,033.99	1,350.26	6.10	15.40	15.40	0	3.58	4.14
Exhaust 1 for GV2	GV2A	378,385.72	4,750,018.20	1,350.26	6.10	15.40	15.40	0	3.58	4.14
Exhaust 2 for GV2	GV2B	378,376.37	4,750,005.93	1,350.26	6.10	15.40	15.40	0	3.58	4.14
Exhaust 1 for GV3	GV3A	378,480.60	4,749,988.70	1,350.26	6.10	15.40	15.40	0	3.58	4.14
Exhaust 2 for GV3	GV3B	378,472.42	4,749,975.63	1,350.26	6.10	15.40	15.40	0	3.58	4.14
Exhaust 1 for GV4	GV4A	378,461.92	4,749,960.16	1,350.26	6.10	15.40	15.40	0	3.58	4.14
Exhaust 2 for GV4	GV4B	378,453.96	4,749,946.95	1,350.26	6.10	15.40	15.40	0	3.58	4.14
Rail Bay	RB1	378,510.00	4,750,098.00	1,350.26	17.22	50.70	50.70	0	11.79	16.02
Rail Bay	RB2	378,510.00	4,750,098.00	1,350.26	17.22	50.70	50.70	0	11.79	16.02
Truck Bay	TB	378,484.00	4,750,070.00	1,350.26	17.22	50.70	50.70	0	11.79	16.02

Instructions for Form MI3

This form is designed to provide the air quality modeler with information on the characteristics of each fugitive source located at the facility. This information may be used by the IDEQ to perform an air quality analysis or to review an air quality analysis submitted with the permit application or requested by the IDEQ.

Please fill in the same company name, facility name, facility ID number, and brief project description as on Form CS in the boxes provided. This is useful in case any pages of the application get separated.

Fugitive sources are typically modeled as either area or volume sources. Area sources are used to model fugitives from sources such as roads or parking lots, while volume sources are typically used to model fugitives from piles. Refer to the State of Idaho Air Quality Modeling Guideline for additional guidance on modeling fugitive sources.

1. Provide the name of the fugitive source. This name should match names used on other submittals to IDEQ and within this application.
2. Provide the identification number for the fugitive source.
3. Provide the UTM locations of the fugitive source. The UTM Easting and UTM Northing are the coordinates for the center of the fugitive source.
4. Provide the elevation of the base of the fugitive source. This elevation must be calculated by the same method as the buildings and receptor elevation.
5. Provide the height of the fugitive source, from the ground. This is used for an elevated release. If the fugitive source is at ground level enter zero.
6. Provide the easterly length of the fugitive source.
7. Provide the northly length of the fugitive source.
8. Provide the angle from north, in degrees. This allows for accurate evaluation of the alignment of the fugitive source.
9. Provide the initial vertical dimension of the fugitive source. Refer to the State of Idaho Modeling Guideline for guidance on estimating this value.
10. Provide the initial horizontal dimension of the fugitive source. This parameter is only used for volume sources. Refer to the State of Idaho Modeling Guideline for guidance on estimating this value.

DEQ AIR QUALITY PROGRAM
1410 N. Hilton, Boise, ID 83706
For assistance, call the
Air Permit Hotline - 1-877-5PERMIT

PERMIT TO CONSTRUCT APPLICATION
Revision 3
4/5/2007

Please see instructions on page 2 before filling out the form.

Company Name:	Great Western Malting Company
Facility Name:	Great Western Malting Company, Pocatello
Facility ID No.:	005-00035
Brief Project Description:	Production of Barley Malt and Barley Feed (Some of Which is Pelletized)

BUILDING AND STRUCTURE INFORMATION

1.	2.	3.	4.	5.	6.	7.
Building ID Number	**Length (ft)**	**Width (ft)**	**Base Elevation (m)**	**Building Height (m)**	**Number of Tiers**	**Description/Comments**
MLTHSE	291	150	1350.26	25.30	1	Existing Malt House
SHOP	90	42	1350.26	4.88	1	Existing Shop
OFFICE	100	89	1350.26	7.62	1	Office
GER2	96	96	1350.26	12.08	1	Germinaton #2 Tank
KILN	128	128	1350.26	13.65	1	Kiln Tank
GER1	96	96	1350.26	12.08	1	Germinaton #1 Tank
GER3	96	96	1350.26	12.08	1	Germinaton #3 Tank
GER4	96	96	1350.26	12.08	1	Germinaton #4 Tank
WH4	41	21	1350.26	3.66	1	Warehouse #4
WH2	42	35	1350.26	4.27	1	Warehouse #2
WH3	79	51	1350.26	4.27	1	Warehouse #3
WUB2	48	40	1350.26	6.10	1	Water Utility Building #2
WRES	35	30	1350.26	6.10	1	Water Reservoir
ERES	41	41	1350.26	6.10	1	Existing Reservoir
WUB1	43	27	1350.26	6.10	1	Water Utility Building #1
KILN_P	135	70	1350.26	19.81	1	Kiln Plenum
GER1_P	55	51	1350.26	8.90	1	Germinaton #1 Plenum
GER2_P	55	51	1350.26	8.90	1	Germinaton #2 Plenum
GER4_P	55	51	1350.26	8.90	1	Germinaton #4 Plenum
GER3_P	55	51	1350.26	8.90	1	Germinaton #3 Plenum
ANBIN2	25	25	1350.26	23.47	1	Analysis Bin #2
ANBIN1	25	25	1350.26	23.47	1	Analysis Bin #1
WRKHSE	91	88	1350.26	70.71	1	Existing Workhouse
BRLYSLO	120	88	1350.26	34.44	1	Existing Barley Storage
MLTSLO	121	88	1350.26	34.44	1	Existing Malt Storage
RAILBAY	148	44	1350.26	12.19	1	Rail Bay
TRKBAY	139	39	1350.26	7.32	1	Truck Bay
STEEPS	164	33	1350.26	28.19	1	Steep House S
STEEPN	41	33	1350.26	37.80	1	Steep House N
MLTSTG	191	71	1350.26	25.60	1	Malt Storage Bins

Instructions for Form MI4

This form is designed to provide the air quality modeler with information on the buildings and structures located at the facility. This information may be used by the IDEQ to perform an air quality analysis or to review an air quality analysis submitted with the permit application or requested by the IDEQ.

Please fill in the same company name, facility name, facility ID number, and brief project description in the boxes provided. This is useful in case any pages of the application get separated.

1. Provide the building ID number.
2. Provide the length of the building.
3. Provide the width of the building.
4. Provide the base elevation of the building. This elevation must be calculated by the same method as the sources and receptor elevation.
5. Provide the height of the building, from the ground.
6. Provide the number of tiers on the building. Refer to the State of Idaho Modeling Guideline for guidance on this topic.
7. Provide a description of the building.

Appendix H – NO_X/NO_2 In-Stack Ratio Documentation

In-Stack NO_2/NO_x Ratio

The existing and new combustion sources included in the air dispersion model for Great Western Malting are all natural gas-fired. The source types include the kiln heaters, boilers and makeup air heaters. The capacities of the burners used in the combustion equipment range from 2 MM Btu/hr to 18.15 MM Btu/hr of heat input.

Modeling for NO2 impacts requires an input value for the in-stack ratio (ISR) of NO2 to NOx. Great Western Malting does not have site-specific information on the ISR for its natural gas-fired sources. The ISR used in the model for onsite sources was selected based on information that is publically available for similar types of sources.

The CAPCOA guidance document, “Modeling Compliance of the Federal 1-hour NO2 NAAQS” October 27, 2011, provided ISR ratio information for natural gas boilers. The guidance document states:

> *2.1.3.2 In-Stack NO2/NOX Ratio Currently, limited information is available on in-stack NO2/NOx ratios nationwide. A literature search of available data revealed in-stack NO2/NOx ratios for a limited number of sources, see Appendix C. If a source is not listed, the source type that best represents the source under review should be used. In addition EPA and some local air district have started collecting in-stack NO2/NOx data that is obtained during annual source testing, if available. These data are being compiled, and new In-stack NO2/NOx ratios and source categories are being developed (Appendix B, p.53).*

The CAPCOA guidance document lists a NO2 content range from 0 – 3.51% for natural gas boilers that are in the 6.6 to 11.4 MM Btu/hr size range. (Reference, CAPCOA, Appendix C, p.57). If the maximum value from this range were used, the resulting ISR is 0.035 for natural gas-fired burners near the sizes of the proposed Great Western Malting equipment.

The EPA ISR beta database was reviewed. The database included information on natural gas-fired boilers, turbines, internal combustion engines and glass furnaces. The data for the boilers were selected as most similar to the Great Western Malting equipment. The average of the ISR data for all of the natural gas-fired boilers in the database was 0.071. A copy of the boiler data from the EPA database is attached for reference.

Based on the information for similar natural gas-fired sources in the CAPCOA document and in the EPA ISR database, an ISR of 0.1 was selected for use in the 1-hour NO2 modeling analysis for the onsite NOx emission sources. This ISR value is 40% greater than the average of values in the EPA database and should be a reasonable but conservative estimate relative to the information available for similar sources.

EPA's NO2 to NOx Ratio Database ISR Information (Ref: NO2_ISR_alpha_database.xlsx; http://www3.epa.gov/scram001/no2_isr_database.htm)

Site Name	Facility ID	Equipment clas	Fuel Type	Equipment mar	Equipment cap	Control Equipm	Analyzer make/	Test date	Load (% of capa	Operating temp	Test type	Output units	Avg. NO2	Avg NO	Avg Nox	% O2	Ratio	Reporting entity
Madera Community Hospital	803	Boiler	NG	AJAX MODEL WEG8000LN0 Boiler	MMBTU/HR	Low NOx Burner w/ FGR	Ecom AC Plus	#########	0	264	Min	PPM	2	17	19	5.9	0.1053	San Joaquin Valley APCD (CA
Madera Community Hospital	803	Boiler	NG	AJAX MODEL WEG8000LN0 Boiler	MMBTU/HR	Low NOx Burner w/ FGR	Ecom AC Plus	21-Jul-09	0	269.4	Min	PPM	3	16	19	5.9	0.1579	San Joaquin Valley APCD (CA
Madera Community Hospital	803	Boiler	NG	AJAX MODEL WEG8000LN0 Boiler	MMBTU/HR	Low NOx Burner w/ FGR	Ecom AC Plus	21-Jul-09	0	269.4	Min	PPM	3	16	19	6	0.1579	San Joaquin Valley APCD (CA
Madera Community Hospital	803	Boiler	NG	AJAX MODEL WEG8000LN0 Boiler	MMBTU/HR	Low NOx Burner w/ FGR	Ecom AC Plus	21-Jul-09	0	269.4	Min	PPM	2	18	20	6	0.1000	San Joaquin Valley APCD (CA
Madera Community Hospital	803	Boiler	NG	AJAX MODEL WEG8000LN0 Boiler	MMBTU/HR	Low NOx Burner w/ FGR	Ecom AC Plus	#########	0	264	Min	PPM	2	18	20	5.8	0.1000	San Joaquin Valley APCD (CA
Madera Community Hospital	803	Boiler	NG	AJAX MODEL WEG8000LN0 Boiler	MMBTU/HR	Low NOx Burner w/ FGR	Ecom AC Plus	14-Jan-10	0	278.6	Min	PPM	2	18	20	6	0.1000	San Joaquin Valley APCD (CA
Madera Community Hospital	803	Boiler	NG	AJAX MODEL WEG8000LN0 Boiler	MMBTU/HR	Low NOx Burner w/ FGR	Ecom AC Plus	14-Jan-10	0	278.6	Min	PPM	2	18	20	6.1	0.1000	San Joaquin Valley APCD (CA
Madera Community Hospital	803	Boiler	NG	AJAX MODEL WEG8000LN0 Boiler	MMBTU/HR	Low NOx Burner w/ FGR	Ecom AC Plus	#########	0	264	Min	PPM	3	17	20	5.8	0.1500	San Joaquin Valley APCD (CA
Madera Community Hospital	803	Boiler	NG	AJAX MODEL WEG8000LN0 Boiler	MMBTU/HR	Low NOx Burner w/ FGR	Ecom AC Plus	#########	0	264	Min	PPM	3	17	20	5.9	0.1500	San Joaquin Valley APCD (CA
Madera Community Hospital	803	Boiler	NG	AJAX MODEL WEG8000LN0 Boiler	MMBTU/HR	Low NOx Burner w/ FGR	Ecom AC Plus	14-Jan-10	0	278.6	Min	PPM	2	19	21	6	0.0952	San Joaquin Valley APCD (CA
Madera Community Hospital	803	Boiler	NG	AJAX MODEL WEG8000LN0 Boiler	MMBTU/HR	Low NOx Burner w/ FGR	Ecom AC Plus	30-Sep-09	0	287.8	Min	PPM	1	23	24	2.9	0.0417	San Joaquin Valley APCD (CA
Madera Community Hospital	803	Boiler	NG	AJAX MODEL WEG8000LN0 Boiler	MMBTU/HR	Low NOx Burner w/ FGR	Ecom AC Plus	05-Nov-09	0	273.6	Min	PPM	2	23	25	5.7	0.0800	San Joaquin Valley APCD (CA
Madera Community Hospital	803	Boiler	NG	AJAX MODEL WEG8000LN0 Boiler	MMBTU/HR	Low NOx Burner w/ FGR	Ecom AC Plus	30-Sep-09	0	287.8	Min	PPM	2	23	25	3.6	0.0800	San Joaquin Valley APCD (CA
Madera Community Hospital	803	Boiler	NG	AJAX MODEL WEG8000LN0 Boiler	MMBTU/HR	Low NOx Burner w/ FGR	Ecom AC Plus	30-Sep-09	0	287.8	Min	PPM	1	25	26	3.1	0.0385	San Joaquin Valley APCD (CA
Madera Community Hospital	803	Boiler	NG	AJAX MODEL WEG8000LN0 Boiler	MMBTU/HR	Low NOx Burner w/ FGR	Ecom AC Plus	05-Nov-09	0	273.6	Min	PPM	2	24	26	6.2	0.0769	San Joaquin Valley APCD (CA

EPA's NO2 to NOx Ratio Database ISR Information (Ref: NO2_ISR_alpha_database.xlsx; http://www3.epa.gov/scram001/no2_isr_database.htm)

Site Name	Facility ID	Equipment clas	Fuel Type	Equipment mar	Equipment cap	Control Equipm	Analyzer make/	Test date	Load (% of capa	Operating temp	Test type	Output units	Avg. NO2	Avg NO	Avg Nox	% O2	Ratio	Reporting entity
Madera Community Hospital	803	Boiler	NG	AJAX MODEL WEG8000LN0 Boiler	MMBTU/HR	Low NOx Burner w/ FGR	Ecom AC Plus	05-Nov-09	0	273.6	Min	PPM	3	23	26	5.8	0.1154	San Joaquin Valley APCD (CA
Madera Community Hospital	803	Boiler	NG	AJAX MODEL WEG8000LN0 Boiler	MMBTU/HR	Low NOx Burner w/ FGR	Ecom AC Plus	05-Nov-09	0	273.6	Min	PPM	3	23	26	5.9	0.1154	San Joaquin Valley APCD (CA
Madera Community Hospital	803	Boiler	NG	AJAX MODEL WEG8000LN0 Boiler	MMBTU/HR	Low NOx Burner w/ FGR	Ecom AC Plus	21-Jul-09	0	269.4	Min	PPM	1	26	27	2.8	0.0370	San Joaquin Valley APCD (CA
Madera Community Hospital	803	Boiler	NG	AJAX MODEL WEG8000LN0 Boiler	MMBTU/HR	Low NOx Burner w/ FGR	Ecom AC Plus	20-Oct-09	0	273.4	Min	PPM	2	25	27	2.9	0.0741	San Joaquin Valley APCD (CA
Madera Community Hospital	803	Boiler	NG	AJAX MODEL WEG8000LN0 Boiler	MMBTU/HR	Low NOx Burner w/ FGR	Ecom AC Plus	30-Sep-09	0	287.8	Min	PPM	2	25	27	2.8	0.0741	San Joaquin Valley APCD (CA
Madera Community Hospital	803	Boiler	NG	AJAX MODEL WEG8000LN0 Boiler	MMBTU/HR	Low NOx Burner w/ FGR	Ecom AC Plus	20-Oct-09	0	273.4	Min	PPM	2	26	28	2.6	0.0714	San Joaquin Valley APCD (CA
Madera Community Hospital	803	Boiler	NG	AJAX MODEL WEG8000LN0 Boiler	MMBTU/HR	Low NOx Burner w/ FGR	Ecom AC Plus	20-Oct-09	0	273.4	Min	PPM	2	26	28	2.8	0.0714	San Joaquin Valley APCD (CA
Madera Community Hospital	803	Boiler	NG	AJAX MODEL WEG8000LN0 Boiler	MMBTU/HR	Low NOx Burner w/ FGR	Ecom AC Plus	20-Oct-09	0	273.4	Min	PPM	3	25	28	4.7	0.1071	San Joaquin Valley APCD (CA
Madera Community Hospital	803	Boiler	NG	AJAX MODEL WEG8000LN0 Boiler	MMBTU/HR	Low NOx Burner w/ FGR	Ecom AC Plus	30-Sep-09	0	287.8	Min	PPM	3	25	28	5.2	0.1071	San Joaquin Valley APCD (CA
Madera Community Hospital	803	Boiler	NG	AJAX MODEL WEG8000LN0 Boiler	MMBTU/HR	Low NOx Burner w/ FGR	Ecom AC Plus	21-Jul-09	0	269.4	Min	PPM	1	28	29	3.2	0.0345	San Joaquin Valley APCD (CA
Madera Community Hospital	803	Boiler	NG	AJAX MODEL WEG8000LN0 Boiler	MMBTU/HR	Low NOx Burner w/ FGR	Ecom AC Plus	20-Oct-09	0	273.4	Min	PPM	2	27	29	2.5	0.0690	San Joaquin Valley APCD (CA
Madera Community Hospital	803	Boiler	NG	AJAX MODEL WEG8000LN0 Boiler	MMBTU/HR	Low NOx Burner w/ FGR	Ecom AC Plus	08-Dec-09	0	354.6	Min	PPM	3	27	29	7.7	0.1034	San Joaquin Valley APCD (CA
Madera Community Hospital	803	Boiler	NG	AJAX MODEL WEG8000LN0 Boiler	MMBTU/HR	Low NOx Burner w/ FGR	Ecom AC Plus	08-Dec-09	0	354.6	Min	PPM	3	27	30	7.8	0.1000	San Joaquin Valley APCD (CA
John Bean Tech Corp	497	Bioler	NG	KEWANEE BOILER KF15-1562-6	MMBTU/Hr		Bacharach ECA450	13-Feb-08	25	335	MIN	PPM	1	49	50	3	0.0200	San Joaquin Valley APCD (CA
John Bean Tech Corp	497	Bioler	NG	KEWANEE BOILER KF15-1562-6	MMBTU/Hr		Bacharach ECA450	13-Feb-08	50	370	MIN	PPM	1	54	55	3	0.0182	San Joaquin Valley APCD (CA
John Bean Tech Corp	497	Bioler	NG	KEWANEE BOILER KF15-1562-6	MMBTU/Hr		Bacharach ECA450	13-Feb-08	75	390	MIN	PPM	2	55	57	5.8	0.0351	San Joaquin Valley APCD (CA

EPA's NO2 to NOx Ratio Database ISR Information (Ref: NO2_ISR_alpha_database.xlsx; http://www3.epa.gov/scram001/no2_isr_database.htm)

Site Name	Facility ID	Equipment clas	Fuel Type	Equipment mar	Equipment cap	Control Equipm	Analyzer make/	Test date	Load (% of capa	Operating temp	Test type	Output units	Avg. NO2	Avg NO	Avg Nox	% O2	Ratio	Reporting entity
John Bean Tech Corp	497	Bioler	NG	CLAYTON BOILER EO-200-3FM	MMBTU/Hr		Bacharach ECA450	22-Jan-09	0	233	MIN	PPM	0	59	59	3		San Joaquin Valley APCD (CA
John Bean Tech Corp	497	Bioler	NG	KEWANEE BOILER KF15-1562-6	MMBTU/Hr		Bacharach ECA450	13-Feb-08	100	392	MIN	PPM	2	57	59	3	0.0339	San Joaquin Valley APCD (CA
John Bean Tech Corp	497	Bioler	NG	CLAYTON BOILER EO-200-3FM	MMBTU/Hr		Bacharach ECA450	22-Jan-09	0	256	MIN	PPM	1	61	62	3	0.0161	San Joaquin Valley APCD (CA
John Bean Tech Corp	497	Bioler	NG	CLAYTON BOILER EO-200-3FM	MMBTU/Hr		Bacharach ECA450	22-Jan-09	0	246	MIN	PPM	1	62	63	3	0.0159	San Joaquin Valley APCD (CA
John Bean Tech Corp	497	Bioler	NG	CLAYTON BOILER EO-200-3FM	MMBTU/Hr		Bacharach ECA450	22-Jan-09	0	216	MIN	PPM	0	64	64	3		San Joaquin Valley APCD (CA
John Bean Tech Corp	497	Bioler	NG	CLAYTON BOILER EO-200-3FM	MMBTU/Hr		Bacharach ECA450	22-Jan-09	0	250	MIN	PPM	1	63	64	3	0.0156	San Joaquin Valley APCD (CA
John Bean Tech Corp	497	Bioler	NG	CLAYTON BOILER EO-200-3FM	MMBTU/Hr		Bacharach ECA450	22-Jan-09	25	280	MIN	PPM	1	66	67	3	0.0149	San Joaquin Valley APCD (CA
John Bean Tech Corp	497	Bioler	NG	CLAYTON BOILER EO-200-3FM	MMBTU/Hr		Bacharach ECA450	22-Jan-09	100	292	MIN	PPM	2	67	69	3	0.0290	San Joaquin Valley APCD (CA
John Bean Tech Corp	497	Bioler	NG	CLAYTON BOILER EO-200-3FM	MMBTU/Hr		Bacharach ECA450	22-Jan-09	50	281	MIN	PPM	1	69	70	3	0.0143	San Joaquin Valley APCD (CA
John Bean Tech Corp	497	Bioler	NG	CLAYTON BOILER EO-200-3FM	MMBTU/Hr		Bacharach ECA450	22-Jan-09	75	315	MIN	PPM	2	73	75	3	0.0267	San Joaquin Valley APCD (CA
John Bean Tech Corp	497	Bioler	NG	CLAYTON BOILER EO-200-3FM	MMBTU/Hr		Bacharach ECA450	22-Jan-09	100	317	MIN	PPM	2	75	77	3	0.0260	San Joaquin Valley APCD (CA

0.0711 **avg. all boilers**

8.0 Electronic Data Files

Electronic files of the application and supporting data are contained on the enclosed CDs. The first CD contains a copy of the entire application plus copies of the spreadsheets with the emission calculations. The second CD contains a copy of just the modeling report plus the files used in the air dispersion modeling analysis.

Appendix to Pre-Permit Construction Approval and Application to Modify the Permit to Construct

(Permit No. P-060312)

Expansion of Malt Processing at the Great Western Malting Pocatello Plant

(Facility ID No. 005-00035)

Submitted to:

Idaho Department of Environmental Quality

Submitted by:

Great Western Malting Co.

December 3, 2015

CONTENTS

Section	Page
	8-1

Appendix

Appendix A- Manufacturer's Information for Air-to-Air Heat Exchanger Burners

KINEDIZER® LE

High capacity low NOx gas burners

- Field proven low emissions. State-of-the-art low NOx firing - adjustable for application flexibility
- Lower NOx and less excess air than standard KINEDIZER® burners
- Rugged design for oxidizers, process heaters, kilns, furnaces, dryers, waste incineration and other high temperature applications
- Available in a wide range of capacities, each with turndown as high as 20:1
- Burns natural gas, propane or other fuel gases
- Provides excellent stirring and mixing with its medium velocity exhaust
- Accepts preheated and vitiated combustion air

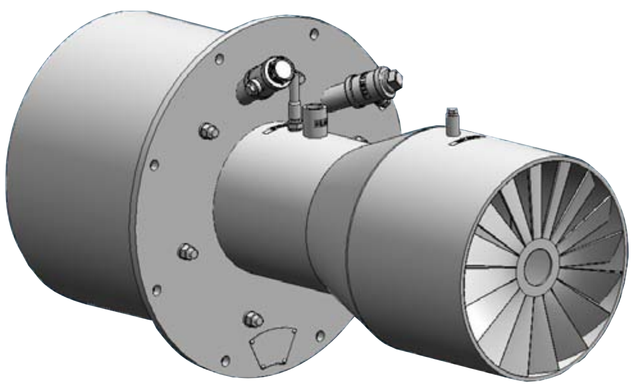
Product description

The KINEDIZER® LE burner is a nozzle-mix, medium-velocity design. Using advanced mixing technology, the burner produces low emissions with very little excess air. Ruggedly built with a reinforced refractory block and steel burner body and nozzle, it burns natural gas, propane or other gaseous fuels. Combustion air is supplied with an external blower. Accurate air and fuel modulation can be accomplished by the MAXON MICRO-RATIO® valve or SMARTLINK® technology.

Combustion air can range from 21% down to 17% O_2 if preheated and from ambient temperature up to 660°F (max. 800°F) on request. Maximum chamber temperature is 2000°F .

Turndown up to 20:1.

Contact MAXON for correct application details.



View of KINEDIZER® LE burner

Available KINEDIZER® LE sizes

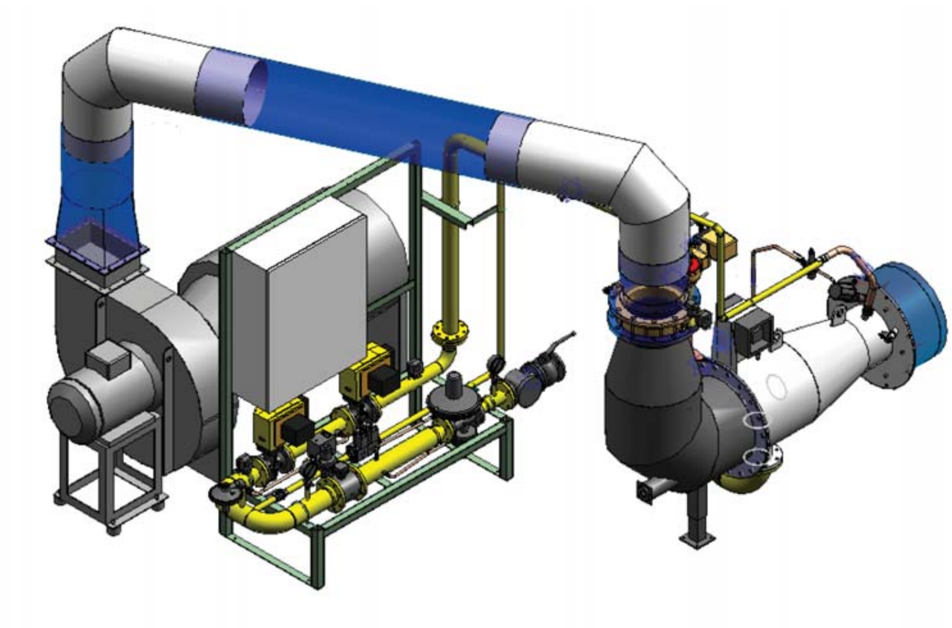
Typical burner data
Fuel: natural gas at 60°F with 1000 Btu/ft^3 (st) HHV - sg = 0.6 [1]
Combustion air: 60°F - 21% O_2 - 50% humidity - sg = 1.0 [1]
Stated pressures are indicative. Actual pressures are a function of air humidity, altitude, type of fuel and gas quality.

KINEDIZER® LE size		1-1/2”	3”	4”	6”	8”	10”	14”	16”
Maximum capacity @ n=1.3	MBtu/h	0.54	2.4	4.6	9.8	15.8	24.3	55	75
Air flow at maximum capacity	scfm	117	520	997	2123	3423	5265	11917	16250
Advised pilot capacity	MBtu/h	0.1	0.2	0.2	0.3	0.5	1.0	1.0	1.0
Combustion air pressure @ inlet [2]	“wc	28	32	32	32	32	32	32	30
Natural gas inlet pressure differential	“wc	55	52	42	64	40	75	120	220

[1] sg (specific gravity) = relative density to air (density air = 0.0763 lb/ft^3 (st))
[2] Combustion air pressure required at full capacity, relative to process. Add 5% safety margin + piping & control valve pressure drops for blower sizing.

Applications

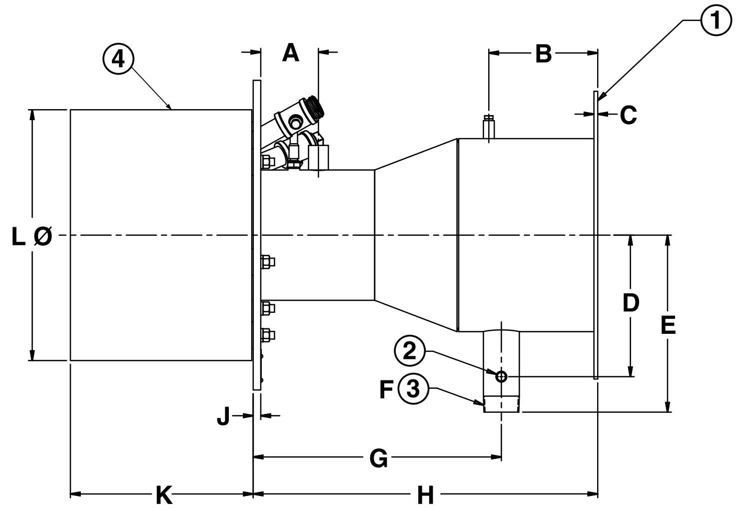
KINEDIZER® LE burners may be applied to a variety of applications for low to ultra-low emissions. The rugged design of the KINEDIZER® LE burner is ideal for oxidizers and incinerators, process heaters, kilns, furnaces, and other high temperature applications.



KINEDIZER® LE burner with pipe train, control panel and combustion air blower

Dimensions and weights

1) Optional air inlet flange
2) 1/4" NPT gas test connection
3) Main gas inlet
4) Standard block or block with sleeve option



Dimensions in inches unless stated otherwise												
Burner size	A	B	C	D	E	F Ø NPT	G	H	J	K	L Ø	Weight lbs
1-1/2"	2.0	1.97	0.25	3.6	4.6	1/2"	5.7	7.86	0.25	9.5	8.6	66
3"	2.99	3.12	0.25	4.69	6.25	1-1/4"	6.94	10.06	0.375	9.5	10.4	100
4"	2.31	3.84	0.25	5.94	7.5	1-1/2"	11.24	15.09	0.375	9.5	12.9	165
6"	3.3	5.0	0.25	7.81	9.38	1-1/2"	14.76	19.75	0.5	12.1	14.6	265
8"	3.81	7.2	0.25	9.35	11.69	2"	16.42	22.79	0.5	12.1	16.6	331
10"	3.81	7.2	0.25	11.97	14.31	2"	23.86	29.71	0.5	12.1	18.7	662
14"	3.81	11.12	0.25	13.66	16.25	3" [1]	37.08	48.21	0.5	12.0	23.9	950
16"	3.81	11.12	0.25	16.66	19.25	3" [1]	46.08	57.25	0.5	15.2	26.75	1030

[1] 3" ANSI raised face 150# slip on flange connection

Typical emissions

The KINEDIZER® LE burner is capable of low NOx when given excess air, typically 20-30% at high fire.

The same burner, when adjusted for on-ratio operation, will give low CO and high thermal efficiency. With flue gas recirculation, the emissions and efficiency can be further improved.

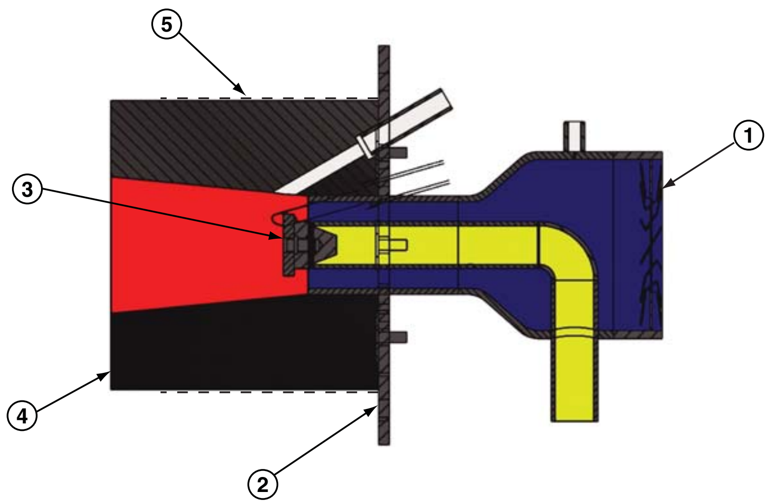
Read "Specifications of KINEDIZER® LE burners" for more detailed information on KINEDIZER® LE burners.

Specifications of KINEDIZER® LE burners

Typical burner data Fuel: natural gas at 60°F with 1000 Btu/ft^3 (st) HHV - sg = 0.6 [1] Combustion air: 60°F - 21% O_2 - 50% humidity - sg = 1.0 [1] Stated pressures are indicative. Actual pressures are a function of air humidity, altitude, type of fuel and gas quality.									
KINEDIZER® LE size		1-1/2”	3”	4”	6”	8”	10”	14”	16”
Max. capacity @ n=1.3 (low NOx) [2]	MBtu/h	0.54	2.4	4.6	9.8	15.8	24.3	55	75
Max. capacity @ n=1.1	MBtu/h	0.59	2.6	5.2	11.2	17.7	28.5	60	85
Min. capacity	KBtu/h	27	120	230	490	790	1215	2750	3750
Turndown @ n=1.3 [2]		20:1	20:1	20:1	20:1	20:1	20:1	20:1	20:1
Turndown @ n=1.1		22:1	22:1	22:1	22:1	22:1	22:1	22:1	22:1
Air flow at max. capacity	scfm	117	520	997	2123	3423	5265	11917	16250
Air flow at min. capacity	scfm	6	26	50	106	171	263	596	820
Advised pilot capacity [3]	MBtu/h	0.1	0.2	0.2	0.3	0.5	1.0	1.0	1.0
Pilot gas pressure [4]	“wc	<0.4	1.0	<0.4	0.6	1.0	4.0	0.5	0.5
Advised pilot gas piping diameter [5]		1/2”	3/4”	3/4”	3/4”	1”	1-1/2”	1-1/2”	1-1/2”
Combustion air pressure @ inlet [6]	“wc	28	32	32	32	32	32	32	30
Combustion air pressure differential [7]	“wc	26	28	29	31	27	30	28	28
Natural gas inlet pressure differential [8]	“wc	55	52	42	64	40	75	120	220
Flame length @ n=1.3 [2]	ft	1	1.5	2	4	6	9	10	10
Flame diameter @ n=1.3 [2]	ft	0.5	0.75	1	1.5	3	4	4	5
Flame length @ n=1.1	ft	1.5	2.5	4	6	8	10	11	11
Flame diameter @ n=1.1	ft	0.5	0.75	1	1.5	3	4	4	5

[1] sg (specific gravity) = relative density to air (density air = 0.0763 lb/ft^3 (st))
[2] n=1.3 meaning 30% excess air
[3] Most installations will require a stronger pilot (advised pilot capacity will be required)
[4] Natural gas pressure at pilot burner gas inlet (absolute minimum pilot capacity)
[5] For information only - strong pilots require adapted piping
[6] Differential air pressure needed to the burner
[7] Air pressure as measured at the air pressure connection port
[8] Differential natural gas pressure required at burner gas inlet (gas inlet test connection) relative to process, for the “n=1.3” maximum capacities.

Materials of construction



Item number	Burner part	Material
1	Burner housing	Carbon steel, painted [1]
2	Burner parts (in contact with furnace)	AISI 304 (1.4301)
3	Burner tip	AISI 310 (1.4541)
4	Burner block	Castable refractory [2]
5	Burner block sleeve (optional)	AISI 304 (1.4301)

[1] Optional available: 100% stainless steel burner
[2] Typical composition of castable refractory: refractory with 50% SiO_2, 45% Al_2O_3 and smaller fractions of iron oxide, titanium, lime, reinforced with needles (AISI 304-1.4301)

Appendix B-Manufacturer’s Information for Steep Building Makeup Air Heaters (MAU1-MAU2)

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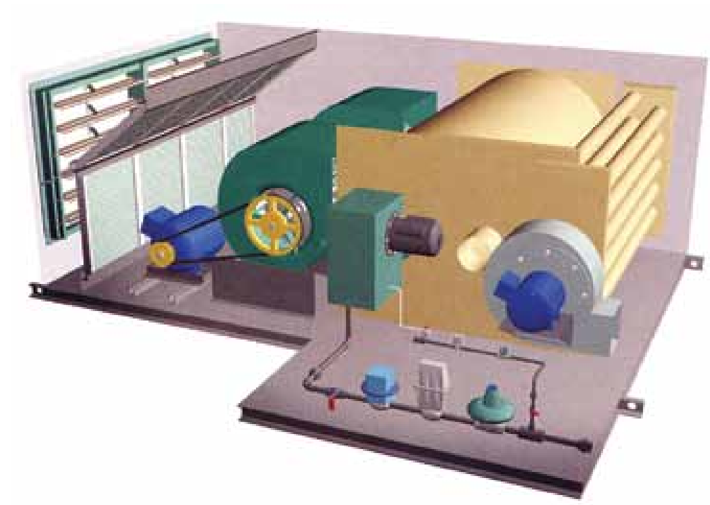
Model PCD Indirect-Fired, Vertical/Horizontal, Indoor/Outdoor, Packaged, Makeup Air Heating and Air Conditioning System



Contents

MODELS PCD, HPCD

IMPORTANT: Specifications are subject to change without notice. This guide is intended to provide specifications and technical information only.

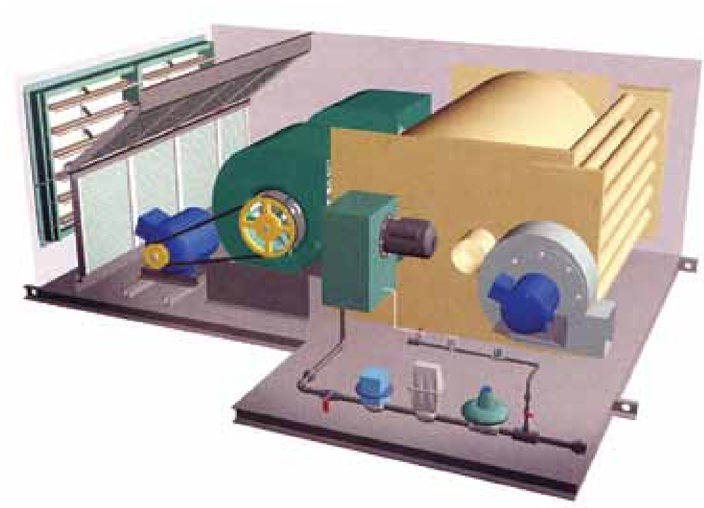
This guide is not intended to be an instruction manual. When installing HVAC Equipment, you must check and conform to all local and national building codes. Improper installation of HVAC Equipment could be dangerous. Consult manufacturer's installation manual for instructions and important warnings.

In keeping with our policy of continuous product improvement, we reserve the right to alter, at any time, the design, construction, dimensions, weights, etc., of equipment information shown here.

REZNOR®

MODELS PCD, HPCD

Horizontal or Vertical, Indoor or Outdoor, Indirect Fired Power Burner, Makeup Air Heating, Ventilating and Air Conditioning System.



DESCRIPTION

The Reznor Model PCD Series units are indirect-fired/makeup air system designed for either indoor or outdoor installation. Units can be configured for either vertical, horizontal for floor mount, outdoor pad mount, rooftop or suspended installation. Select from top, bottom or horizontal discharge supply air options. Model PCD systems are available to operate on either natural gas, propane or fuel oil. This catalog details features and specifications for heating capacities ranging from 200 to 6,000 MBH output. Larger sizes are available on special order basis (contact your Reznor Representative for more more information) High cfm versions (Model HPCD) are also available.

The basic cabinet is constructed of 18 gauge galvaneal with a grey enamel finish. Other finishes are available. The standard cabinet is a single wall with 1" thick, 1.5 lb. neoprene coated insulation. High density (2 lb.) insulation or 2" thick insulation can be selected. A 22 gauge interior liner is standard on the burner section. Optional solid (for cleaning) or perforated (for sound attenuation) liners are available on other sections.

Vertical units (Model PCDV) can be shipped with a 3' or 5' mounting stand for field attachment. The mounting stand can be screened, or it can be insulated with one or two flanged inlets with or without dampers. A louvered inlet plenum can be shipped separately with outdoor vertical or horizontal units.

Discharge air openings can be shipped with two position motorized discharge dampers - low leak dampers also available. Other air distribution options include trapezoidal cowls with horizontal louvers; 4-sided (360 degrees) louvered discharge plenum; or 90 degree discharge cowls.

A 409 stainless steel primary and secondary heat exchanger is standard on Model PCD. Optional 304 stainless steel can be substituted for both heat exchangers or only the primary heat exchanger. Model PCD high can be ordered with a standard gravity vent or induced draft vent.

Units can be arranged for 100% outside or return air, or a mixing box can be specified with 3-position motorized dampers. Other modules can be included with Model PCD and shipped separately for field attachment including an inlet louvered hood, evaporative cooling section, filter cabinet, service platform and/or cooling coil cabinet.

Model PCD and HPCD meet ETL (ANSI) Standards for installation in the United States and CGA (CSA) Standards for installation in Canada.

All units are factory wired, piped and test fired.

STANDARD FEATURES

- Single wall cabinet (with interior 22 gauge liner on burner section)
- Gray enamel finish on 18 gauge Galvaneal cabinet construction
- 1" thick 1.5 lb. neoprene coated fiberglass insulation
- Natural gas operation
- 409 stainless steel primary and secondary heat exchangers
- Gravity vent exhaust
- 230/1/60 supply voltage
- Burner manifold meets ETL (ANSI) or CGA (CSA) standards
- 3:1 turndown ratio modulating power burner

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MODELS PCD, HPCD (cont'd)

OPTIONAL FEATURES - Factory Installed

- 22 gauge solid or perforated interior cabinet metal liner on blower, filter, mixing box, or inlet plenum sections.
- Special material cabinet coating
- 1" thick high density (2 lb.) or 2" thick cabinet insulation
- Propane or fuel oil operation
- Power vent exhaust
- 304 stainless steel primary and secondary heat exchangers (or 304 primary with a 409 secondary stainless steel heat exchanger)
- 208/3/60, 230/3/60, 460/3/60, or 575/3/60 supply voltages
- Vibration isolation
  - 1" deflection motor/blower spring vibration isolation
  - 2" deflection motor/blower spring vibration isolation
  - Motor/blower rubber-in-shear isolation
  - 1" external spring isolation under unit channel base
  - 2" external spring isolation under unit channel base
  - Seismic isolation, pad type
  - External spring hangers - 1" deflection
  - External spring hangers - 2" deflection
  - Seismic isolation, hanger type
- Left or right hand controls
- Extended lube lines
- Vertical or horizontal unit configuration
- Top, bottom or horizontal supply discharge air
- Two position motorized discharge air shutoff damper, spring return (also available with low leak airfoil type dampers)
- Outdoor units
  - Weather-housing covers the control section on outdoor units
  - Roof slopes away from weather-housing on Model PCDH 125 and larger
- Manifold meets IRI and/or FM requirements
- Up to 15:1 turndown ratio modulating burner
- UV flame supervision
- Unit mounted discharge temperature sensor
- Premium efficiency ODP motors or TEFC motors
- Variable frequency drive
- Convenience outlet
- Rain-tight safety disconnect switch

OPTIONAL FEATURES - Field Installed

- Service Platform
- Discharge air attachments
  - Trapezoidal, 3 facet cowl with horizontal louvers (also available with double deflection louvers)
  - 4-sided (360 deg.) louvered discharge plenum
  - 90 deg. or 45 deg. louvered nozzles
- 3' or 5' stand for vertical indoor units
  - Screened mounting stand
  - Insulated stand with one or two flanged inlet air openings
  - Insulated stand with one or two inlet openings with dampers
- Filter section (with 2" permanent or pleated filters)
  - Flat filter rack
  - V-bank filter rack
- Mixing box with 3-position motorized dampers.
- Louvered inlet plenum (for outdoor units)
- DX or chilled water coil for downstream installation
- Evaporative cooling module
  - Available with stainless steel cabinet
  - 12" thick Glasdek® or Celdek® media
  - 1" or 2" aluminum mesh, washable filters
  - Louvered inlet or screened inlet hood
  - Fill and drain options
- Steam or hot water coil cabinet
- Gas pressure safety switch
- Adjustable freezestat
- Post and/or pre-purge timer
- 16" or 26" roof curb
- Remote Console

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Control Side and Air Arrangement Data

UNIT CONFIGURATION

As previously mentioned, Model PCD can be arranged for horizontal air flow or vertical (up) airflow configuration. There are a variety of air discharge arrangements for each configuration (top, bottom or horizontal air flow). Units can also be configured for left-hand or right-hand controls.

There are a variety of discharge air louvers, cowls and nozzles for supply air openings.

The following table will show you each available configuration and arrangement and the option codes representing each.

Control Side

Option AJ1 Left side controls (when facing air stream)

Option AJ2 Right side controls (when facing air stream)

Discharge Air Arrangement

Option AQ1 Bottom Discharge (Model PCDH)

Option AQ2 Horizontal Discharge (Model PCDH)

Option AQ13 Top Discharge (Model PCDV without Mounting Base), "L" Configuration

Option AQ32 Horizontal Discharge (Model PCDV without Mounting Base), "L" Configuration

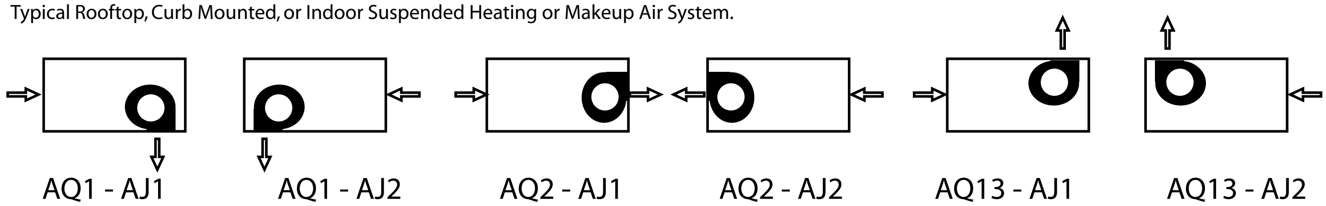
Option AQ33 Horizontal Discharge (Model PCDV with Mounting Base), "I" Configuration

AQ34 **Top** Discharge (Model PCDV with Mounting Base), "I" Configuration

Note: No difference between left-hand and right-hand controls for units with Option AQ34. Unit can be set in place with controls on proper side.

(H)PCDH Configurations

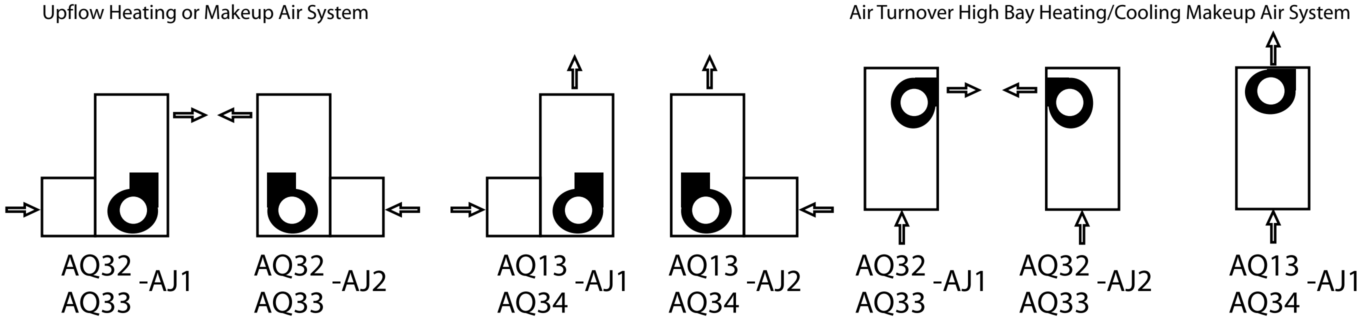
Typical Rooftop, Curb Mounted, or Indoor Suspended Heating or Makeup Air System.



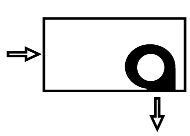
(H)PCDV Configurations

(H)PCDV Uflow "L" Configuration - Typical Indoor, Thru-Wall, or Outdoor Slab Mount Upflow Heating or Makeup Air System

(H)PCDV Uflow "I" Configuration* - Typical Indoor or Outdoor Air Turnover High Bay Heating/Cooling Makeup Air System



Example Configuration Nomenclature



Air flow directions and control side illustrations as seen when facing the unit from the control side
PCDH (Horizontal Configuration)
AQ1 Option - bottom discharge
AJ1 Option - Left side controls when facing air flow.

* If (H)PCDV is ordered with an AVA option, the AW6 or AW15 V-bank filter section will stack on top of the AVA base in an "I" configuration. Otherwise, the V-bank filter section will be in the "L" configuration shown. For draw through coil cabinets in the "L" configuration, order option AU5 or AU6. For blow through upflow A-Coil cabinets in the "I" configuration, order option AU2A or AU3A.

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CONFIGURATION SELECTION

How to Specify a configuration

Model	Description
PCDH	Horizontal Indirect Fired Unit
HPCDH	High CFM Horizontal Indirect Fired Unit
PCDV	Vertical Indirect Fired Unit
HPCDV	High CFM Vertical Indirect Fired Unit

Size	MBH Input	MBH Output
20	250	200
25	312.5	250
35	437.5	350
40	500	400
45	562.5	450
55	687.5	550
65	812.5	650
75	937.5	750
85	1,062.5	850
100	1,250	1,000
125	1,562.5	1,250
150	1,875	1,500
175	2,187.5	1,750
200	2,500	2,000
250	3,125	2,500
275	3,437.5	2,750
300	3,750	3,000
325	4,062.5	3,250
350	4,375	3,500
400	5,000	4,000
500	6,250	5,000
600	7,500	6,000

SIZE SELECTION

How to determine the size of Model PCD

Model PCD are designated by their MBH output. Thus a PCD75 has 750 MBH output, or 750,000 BTUH.

- All PCD units are 80% efficient at high fire, thus, output is BTUH input x 0.80
- Once you have chosen your required BTUH output, you can use BTUH output ÷ 0.80 to find your required input, or actual gas consumption. Using the desired output you can select your model.
- Choose your airflow (this may be your first step if the unit is applied in a make-up air situation)
- Calculate your TSP (add your ESP with your accessories – accessory pressure drops can be found after the unit ESP table). With your airflow and TSP selected you can find your BHP from the performance table.
- Given the entering and leaving air dry bulb temperatures or temperature rise, the equation below can be used to calculate the required MBH capacity
  - MBH Capacity = (CFM x C x (LAT-EAT)) ÷ 0.80 ÷ 1000
  - MBH capacity: BTUH/1000 (British Thermal Units per hour)
  - CFM: Cubic Feet per Minute of air
  - C: Gas constant of 1.08 based on air density at 75°F
  - EAT: Entering air dry bulb temperature (°F)
  - LAT: Leaving air dry bulb temperature (°F)
  - 0.8: (80%) Series Efficiency

Example 1: Make-Up Air

A manufacturing facility needs pressurization via makeup air. A pressurization of 10% is deemed to be appropriate, and it is determined that 25,720 CFM exhaust is required. The design ambient is -20°F, and desired discharge temperature is 70°F. Units will be roof mounted, down discharge, and will have an ESP of 0.60" w.c. Select the appropriate size, and find the BHP for the unit.

Selection:

- Since we are exhausting 25,720 CFM, and desire 10% pressurization, we can calculate that we need 28,300 CFM of supply air (25,720 x 110% = 28,300)
- We know our EAT = -20°F, and LAT = 70°F, thus we can calculate:
  - MBH Output Capacity = (CFM x C x (LAT-EAT)) ÷ 1000
  - MBH Output Capacity = (28,300 x 1.08 x (70 - (-20))) ÷ 1000
  - MBH Output Capacity = 2,750.76
- The closest size available is the Model PCDH275 which has 2,750 MBH output, and 3,437.5 MBH input

We can now calculate our TSP:

- We are selecting the basic options – inlet filters and damper
- Inlet damper = 0.1" w.c.
- Inlet Filters = 0.3" w.c.
  - TSP = ESP + Accessories
  - TSP = 0.60 + 0.1 + 0.3
  - TSP = 1.0" W.C.
- Consulting the chart for the PCD275 at 28,300 CFM and 1.0" W.C we find our BHP = 16.28 BHP – Thus we need a 20.0 HP motor minimum.

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CONFIGURATION SELECTION (cont'd)

How to Specify a configuration

Example 2: Heat-Vent Unit

A small warehouse needs a minimum of 20% fresh air in unoccupied (night time) mode and 100% fresh air in occupied mode (during the day with forklift in the building). It has been calculated that at -30°F the room loses 1,000,000 BTUH. It has been determined that 11,000 CFM is required for the application. The outdoor air is -30°F, and desired leaving air is 75°F. Return air will be 70°F. ESP is calculated to be 0.5" w.c. Select the appropriate model and find the BHP for the unit.

Selection:

Part 1 (Unoccupied mode)

- We only bring in 20% outside air in this mode, thus 2,200 CFM is outside air and 8,800 CFM is return air
- We know our EAT for outside air = -30°F, and LAT = 75°F, thus we can calculate:
  - MBH Capacity = (CFM x C x (LAT - EAT)) ÷ 1000
  - MBH Capacity = (2,200 x 1.08 x (75 - (-30))) ÷ 1000
  - MBH Capacity = 249.48
- We also know that the room is losing 1,000 MBH, thus we need to add that to the calculation. Thus the total Heat input capacity required = 1,250 MBH
- Before we select our model we must check the occupied mode to ensure we have sufficient heat capacity.

Part 2 (Occupied mode)

- We will be delivering 11,000 CFM of outside in this mode
- We know our EAT for outside air = -30°F, and LAT = 75°F, thus we can calculate:
  - MBH Capacity = (CFM x C x (LAT - EAT)) ÷ 0.80 ÷ 1000
  - MBH Capacity = (11,000 x 1.08 x (75 - (-30))) ÷ 0.80 ÷ 1000
  - MBH Capacity = 1,247.40
- Thus to satisfy both options we need to use a PCDH125.

Note: In this example we are assuming there is an alternate source of heat that will be used during occupied mode to make-up for the heat loss of the warehouse, which will not be used in unoccupied mode.

We can now calculate our TSP:

- We are selecting the basic options – inlet filters and damper
- Inlet damper = 0.1" w.c.
- Inlet Filters = 0.3" w.c.
  - TSP = ESP + Accessories
  - TSP = 0.50 + 0.1 + 0.3
  - TSP = 0.9" W.C. (Round up to 1.0" w.c.)
- Consulting the chart for the PCDH125 at 11,000 CFM (use 11,574 CFM) and 1.0" w.c., we find our BHP = 5.75 BHP – We can use a 7.5 hp motor.

Example 3: Heating Only Unit

A door heater for a large overhead door can potentially see 100% fresh air during times when the overhead doors open frequently. Thus a durable Model PCD unit should be selected for this application. The appropriate amount of air is determined to be 18,000 CFM at 0.5" w.c. for the vestibule, and 1,250 MBH is calculated to be the appropriate amount of heat capacity required. Select the appropriate model and find the BHP for the unit.

Selection:

- Since the heating load calculation has already been completed we simply need to use the heating capacity and match it up with the appropriate Model PCD
- PCD125 is the appropriate model for 1,250 MBH

We can now calculate our TSP:

- We are selecting the basic options – inlet filters and damper
- Inlet damper = 0.1" w.c.
- Inlet Filters 0.3" w.c.
  - TSP = ESP + Accessories
  - TSP = 0.50 + 0.1 + 0.3
  - TSP = 0.9" w.c. (Round up to 1.0" W.C)
- Consulting the chart for the PCD125 at 18,000 CFM (this value falls between 16,534 CFM and 19,290 CFM) and 1.0" W.C we find our BHP is between 9.59 BHP and 13.12 BHP. A 15 HP motor should be used.

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PERFORMANCE SPECIFICATION (cont’d)

Pressure Drop Table

Model PCD125 - 1,562.5 MBH Input - 1,250 MBH Output

Air Capacity (CFM)	Temp. Rise °F	0.25” W.C.		0.5” W.C.		0 .75” W.C.		1.0” W.C.		1.5” W.C		2.0” W.C.		Gas Conn. Inches
		Blower	BHP	Blower	BHP	Blower	BHP	Blower	BHP	Blower	BHP	Blower	BHP	
28935	40	2-22x22	16.22	2-22x22	17.62	2-22x22	19.04	2-22x22	20.51	2-22x22	23.54	2-22x22	26.74	
23148	50	2-20x20	10.76	2-20x20	11.82	2-20x20	12.91	2-20x20	14.02	2-20x20	16.35	2-20x20	18.79	
19290	60	2-20x20	6.92	2-20x20	7.84	2-18x18	12.09	2-18x18	13.12	2-18x18	15.20	2-18x18	17.30	
16534	70	2-20x20	4.90	2-18x18	7.81	2-18x18	8.70	2-18x18	9.59	2-18x18	11.39	2-18x18	13.23	
14468	80	2-18x18	5.10	2-18x18	5.87	2-18x18	6.65	2-18x18	7.45	2-18x18	9.05	2-18x18	10.70	1-1/4
12860	90	2-18x18	3.97	2-18x18	4.66	2-15x15	6.51	2-15x15	7.08	2-15x15	8.31	2-15x15	9.59	
11574	100	2-18x18	3.21	2-15x15	4.68	2-15x15	5.20	2-15x15	5.75	2-15x15	6.89	2-15x15	8.07	
10522	110	2-18x18	2.65	2-15x15	3.80	2-15x15	4.30	2-15x15	4.81	2-15x15	5.87	2-15x15	6.97	

Model HPCD125 - 1,562.5 MBH Input - 1,250 MBH Output

Air Capacity (CFM)	Temp. Rise °F	0.25” W.C.		0.5” W.C.		0 .75” W.C.		1.0” W.C.		1.5” W.C		2.0” W.C.		Gas Conn. Inches
		Blower	BHP	Blower	BHP	Blower	BHP	Blower	BHP	Blower	BHP	Blower	BHP	
38580	30	2-25x25	11.38	2-22x22	18.25	2-22x22	19.71	2-22x22	21.19	2-22x22	24.25	2-22x22	27.46	
28935	40	2-22x22	8.31	2-20x20	10.80	2-20x20	11.86	2-20x20	12.95	2-20x20	15.21	2-20x20	17.60	1-1/4
23148	50	2-20x20	5.78	2-20x20	6.65	2-20x20	7.55	2-18x18	11.45	2-18x18	13.44	2-18x18	15.46	
19290	60	2-20x20	3.93	2-18x18	6.39	2-18x18	7.22	2-18x18	8.05	2-18x18	9.74	2-18x18	11.47	

Model PCD150 - 1,875 MBH Input - 1,500 MBH Output

Air Capacity (CFM)	Temp. Rise °F	0.25” W.C.		0.5” W.C.		0 .75” W.C.		1.0” W.C.		1.5” W.C		2.0” W.C.		Gas Conn. Inches
		Blower	BHP	Blower	BHP	Blower	BHP	Blower	BHP	Blower	BHP	Blower	BHP	
27778	50	2-22x22	14.66	2-20x20	18.40	2-20x20	19.66	2-20x20	20.95	2-20x20	23.59	2-20x20	26.33	
23148	60	2-20x20	10.76	2-20x20	11.82	2-20x20	12.91	2-20x20	14.02	2-20x20	16.35	2-20x20	18.79	
19841	70	2-20x20	7.39	2-20x20	8.32	2-20x20	9.29	2-18x18	13.93	2-18x18	16.05	2-18x18	18.21	
17361	80	2-20x20	5.46	2-20x20	6.30	2-18x18	9.63	2-18x18	10.57	2-18x18	12.45	2-18x18	14.37	1-1/2
15432	90	2-20x20	4.23	2-18x18	6.72	2-18x18	7.55	2-18x18	8.39	2-18x18	10.09	2-18x18	11.82	
13889	100	2-18x18	4.68	2-18x18	5.43	2-18x18	6.18	2-15x15	8.34	2-15x15	9.63	2-15x15	10.98	
12626	110	2-18x18	3.81	2-18x18	4.49	2-15x15	6.24	2-15x15	6.81	2-15x15	8.03	2-15x15	9.28	

Model HPCD150 - 1,875 MBH Input - 1,500 MBH Output

Air Capacity (CFM)	Temp. Rise °F	0.25” W.C.		0.5” W.C.		0 .75” W.C.		1.0” W.C.		1.5” W.C		2.0” W.C.		Gas Conn. Inches
		Blower	BHP	Blower	BHP	Blower	BHP	Blower	BHP	Blower	BHP	Blower	BHP	
34722	40	2-25x25	15.07	2-25x25	16.73	2-22x22	26.06	2-22x22	27.70	2-22x22	31.05	2-22x22	34.51	
27778	50	2-25x25	8.94	2-22x22	14.18	2-22x22	15.52	2-20x20	19.21	2-20x20	21.79	2-20x20	24.46	1-1/2
23148	60	2x22-22	8.31	2-20x20	10.80	2-20x20	11.86	2-20x20	12.95	2-20x20	15.21	2-20x20	17.60	

Model PCD175 - 2,187.5 MBH Input - 1,750 MBH Output

Air Capacity (CFM)	Temp. Rise °F	0.25” W.C.		0.5” W.C.		0 .75” W.C.		1.0” W.C.		1.5” W.C		2.0” W.C.		Gas Conn. Inches
		Blower	BHP	Blower	BHP	Blower	BHP	Blower	BHP	Blower	BHP	Blower	BHP	
32407	50	2-22x22	21.80	2-22x22	23.34	2-22x22	24.90	2-22x22	26.50	2-22x22	29.79	2-22x22	33.22	
27006	60	2-22x22	13.62	2-20x20	17.11	2-20x20	18.35	2-20x20	19.61	2-20x20	22.19	2-20x20	24.88	
23148	70	2-20x20	10.76	2-20x20	11.82	2-20x20	12.91	2-20x20	14.02	2-20x20	16.35	2-20x20	18.79	
20255	80	2-20x20	7.77	2-20x20	8.72	2-20x20	9.70	2-20x20	10.72	2-20x20	12.86	2-20x20	15.14	1-1/2
18004	90	2-20x20	5.91	2-20x20	6.78	2-18x18	10.40	2-18x18	11.36	2-18x18	13.31	2-18x18	15.29	
16204	100	2-20x20	4.70	2-18x18	7.48	2-18x18	8.35	2-18x18	9.22	2-18x18	11.00	2-18x18	12.80	
14731	110	2-20x20	3.85	2-18x18	6.10	2-18x18	6.90	2-18x18	7.70	2-18x18	9.33	2-18x18	11.00	

Model HPCD175 - 2,187.5 MBH Input - 1,750 MBH Output

Air Capacity (CFM)	Temp. Rise °F	0.25” W.C.		0.5” W.C.		0 .75” W.C.		1.0” W.C.		1.5” W.C		2.0” W.C.		Gas Conn. Inches
		Blower	BHP	Blower	BHP	Blower	BHP	Blower	BHP	Blower	BHP	Blower	BHP	
40509	40	2-25x25	22.11	2-25x25	23.99	2-25x25	25.93	2-25x25	27.91	2-25x25	32.02	2-25x25	26.35	
32407	50	2-25x25	12.77	2-22x22	20.58	2-22x22	22.10	2-22x22	23.65	2-22x22	26.82	2-22x22	30.13	1-1/2
27006	60	2-22x22	12.03	2-22x22	13.31	2-20x20	16.82	2-20x20	18.05	2-20x20	20.58	2-20x20	23.20	

NOTES:
-All Static Values Include the Blower, Burner, and Casing
-Accesory Static Values Must be Added to Obtain the Total Static
-Brake Horsepower Does Not Include Drive Losses

Consult factory representative for:
-Higher Air Capacities or Special Applications
-Performance Data on Higher Statics than Listed
-Performance Data at Elevations Other Than Sea Level

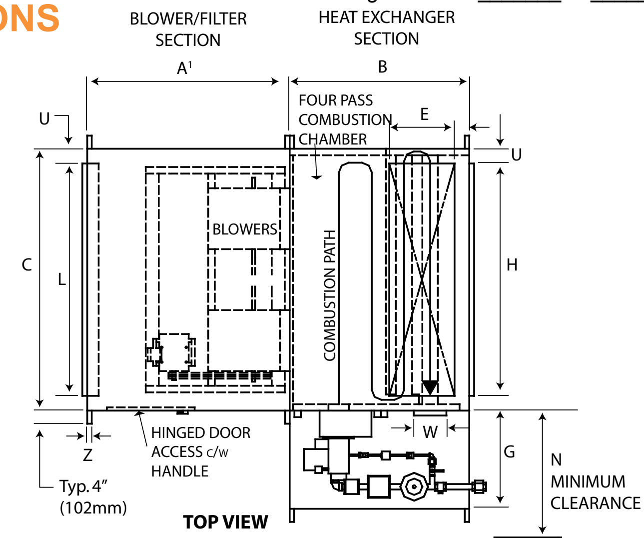
REZNOR®

DIMENSIONS

PCDH Basic Horizontal Unit

Burner Section and Blower/Filter Section only

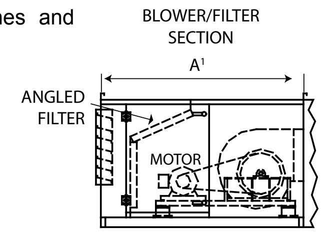
±1/8” (3mm)

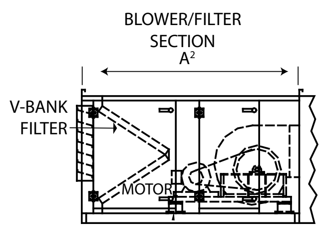


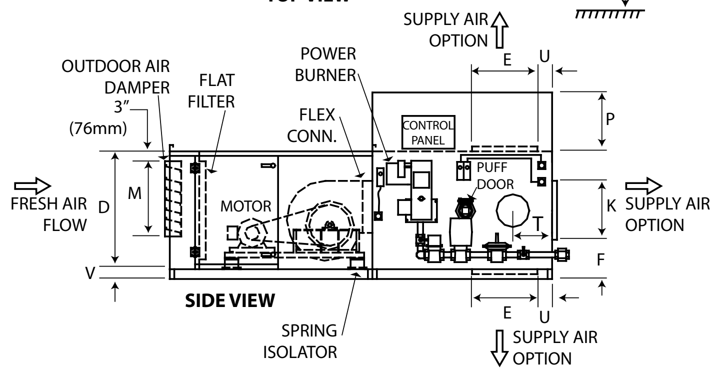
The illiustration to the right shows Model PCDH. On the following pages are dimension drawings for the high cfm horizontal unit, Model HPCDH, vertical unit, Model PCDV, and the high cfm vertical unit, Model HPCDV.

Following those pages are dimension data for modular options.

Dimensions are shown in inches and (millimeters).







**** Burner Section and Blower Section on Sizes 65 and greater are split and shipped separately for field attachment.***

Dimensions ±1/8”

Sizes	A¹	A²	B	C	D	E	F	G	H	K	L	M	N	P	T	U	V	W	Z
20/25	52	62	47	32	32	18	7	30	23	18	23	19	56	18	10	4 1/2	3	8	1 3/8
35/40	60	68	47	48	32	18	7	30	39	18	39	19	56	18	10	4 1/2	3	8	1 3/8
45/55	67	72	55	60	36	20	9	30	51	18	51	23	56	18	12	4 1/2	3	10	1 3/8
65/75	62	67	55	80	36	20	9	30	71	18	71	23	56	18	12	4 1/2	3	10	1 3/8
85/100	68	75	62	80	48	20	15	30	71	18	71	35	56	12	12	4 1/2	4	12	1 9/16
125/150/175	75	85	72	100	54	30	15	32	91	24	91	41	56	12	12	4 1/2	4	12	1 9/16
200/250	80	92	72	120	60	32	15	36	111	30	111	47	56	12	12 1/2	4 1/2	4	12	1 9/16
275/300/325	87	95	84	140	65	32	17 1/2	36	131	30	131	52	56	12	14	4 1/2	4	14	1 9/16
350/400	92	101	100	160	70	32	20	36	148	30	148	57	56	-	11 1/2	6	6	16	2
500/600	107	117	141	180	80	32	16	36	168	48	168	67	56	-	14	6	6	18	2

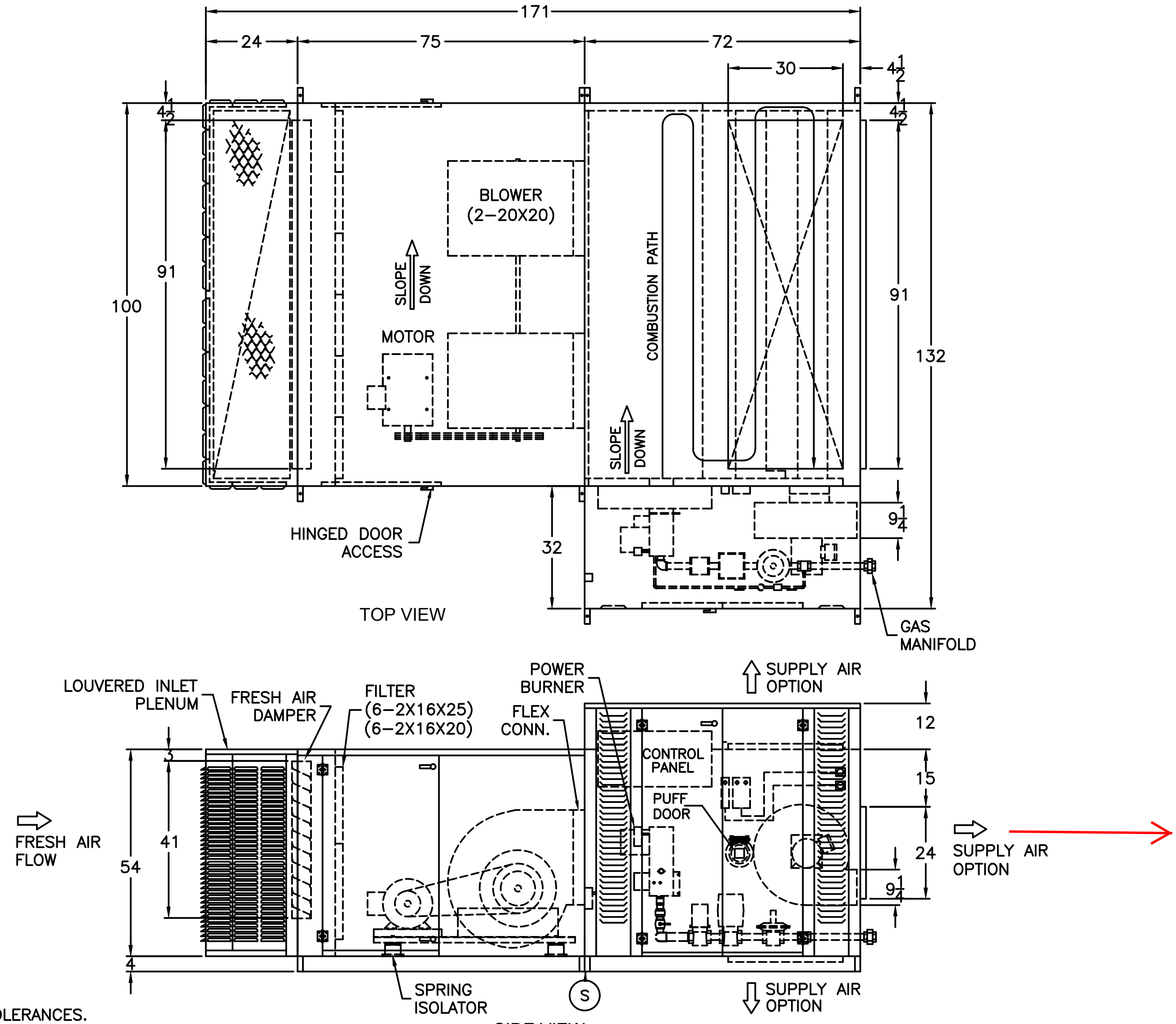
Dimensions (±3mm)

Sizes	A¹	A²	B	C	D	E	F	G	H	K	L	M	N	P	T	U	V	W	Z
20/25	(1,321)	(1,575)	(1,194)	(813)	(813)	(457)	(178)	(762)	(584)	(457)	(584)	(483)	(1,422)	(457)	(254)	(114)	(76)	(203)	(35)
35/40	(1,524)	(1,727)	(1,194)	(1,219)	(813)	(457)	(178)	(762)	(991)	(457)	(991)	(483)	(1,422)	(457)	(254)	(114)	(76)	(203)	(35)
45/55	(1,702)	(1,829)	(1,397)	(1,524)	(914)	(508)	(229)	(762)	(1,295)	(457)	(1,295)	(584)	(1,422)	(457)	(305)	(114)	(76)	(254)	(35)
65/75	(1,575)	(1,702)	(1,397)	(2,032)	(914)	(508)	(229)	(762)	(1,803)	(457)	(1,803)	(584)	(1,422)	(457)	(305)	(114)	(76)	(254)	(35)
85/100	(1,727)	(1,905)	(1,575)	(2,032)	(1,219)	(508)	(381)	(762)	(1,803)	(457)	(1,803)	(889)	(1,422)	(305)	(305)	(114)	(102)	(305)	(40)
125/150/175	(1,905)	(2,159)	(1,829)	(2,540)	(1,372)	(762)	(381)	(813)	(2,311)	(610)	(2,311)	(1,041)	(1,422)	(305)	(305)	(114)	(102)	(305)	(40)
200/250	(2,032)	(2,337)	(1,829)	(3,048)	(1,524)	(813)	(381)	(914)	(2,819)	(762)	(2,819)	(1,194)	(1,422)	(305)	(318)	(114)	(102)	(305)	(40)
275/300/325	(2,210)	(2,413)	(2,134)	(3,556)	(1,651)	(813)	(445)	(914)	(3,327)	(762)	(3,327)	(1,321)	(1,422)	(305)	(356)	(114)	(102)	(356)	(40)
350/400	(2,337)	(2,565)	(2,540)	(4,064)	(1,778)	(813)	(508)	(914)	(3,759)	(762)	(3,759)	(1,448)	(1,422)	-	(292)	(152)	(152)	(406)	(51)
500/600	(2,718)	(2,972)	(3,581)	(4,572)	(2,032)	(813)	(406)	(914)	(4,267)	(1,219)	(4,267)	(1,702)	(1,422)	-	(356)	(152)	(152)	(457)	(51)

	20/25	35/40	45/55	65/75	85/100	125/150/175	200/250	275/300/325	350/400	500/600
Base Weight Lbs.	1,510	1,900	2,375	3,055	3,810	5,335	6,700	8,590	10,280	15,170
with V-Bank Filter Rack	1,675	1,980	2,480	3,220	3,990	5,390	6,765	8,655	10,365	15,295

Base Weight (kg)	(685)	(862)	(1077)	(1386)	(1728)	(2420)	(3039)	(3896)	(4663)	(6881)
with V-Bank Filter Rack	(760)	(898)	(1125)	(1461)	(1810)	(2445)	(3069)	(3926)	(4702)	(6938)

Note: Dimension A¹, Blower Section, includes standard flat filter rack. Optional angled filter rack may be substituted at manufacturer’s discretion. Angle filter rack section does not change unit dimensions. Dimension A² indicates length of blower cabinet with V-Bank Filters.



TOP VIEW

SIDE VIEW

- [ ] RIGHT HAND CONFIG.
- [x] LEFT HAND CONFIG.
  ~~(OPPOSITE SHOWN)~~
- [ ] TOP SUPPLY AIR
- [x] HORIZ. SUPPLY AIR
- [ ] BTM. SUPPLY AIR

NOTES:
Ⓢ SPLIT FOR SHIPMENT

1. 1 1/2 INLET AND DISCHARGE FLANGES
2. SERVICE ACCESS PANELS MUST NOT BE OBSTRUCTED RECOMMENDED CLEARANCE 24 INCHES.
3. DIMENSIONS ARE SUBJECT TO MANUFACTURING TOLERANCES.

FOR REFERENCE USE ONLY, SUBJECT TO CHANGE WITHOUT NOTICE

Rev	By	Revision Description	Date

REZNOR®
PCDH
SERIES

TITLE
PCDH 125–175 HORIZ. CONFIG. OUTDOOR UNIT POWER VENTED C/W FLAT FILTER SECTION AND LOUVERED INLET

DRAWN BY	ISSUED BY	SCALE 1:44	DRW. NO. 60–02536	
CHK. BY	DATE 8/18/15		JOB NO. *	REV

Appendix C-Manufacturer's Information for Germination Vessel Boilers (GVB1-GVB6)

EVOLUTION®

Higher Efficiency Heating Equipment

PREMIUM COPPER-FIN TUBE BOILER CONSTRUCTION AND DESIGN

- **Rugged Heat Exchanger Design**
  - Gasketless headers
  - Water-backed tube sheets
  - 20-Year thermal shock warranty
- **Robust Copper-Fin Tubes**
  - .072" Wall thickness
- **Advanced Combustion**
  - <10 ppm ultra-low NOx emissions
  - <50 dBA noise levels
- **Maintenance-Free Burner**
  - 10 year warranty
- **Unmatched Fireside Heating Surface**
- **Small Footprint**
  - 6 sq. ft / 11 sq. ft.
- **Up to 87% Efficiency**
- **UL Certified Boiler Package**

AHRI CERTIFIED® www.ahridirectory.org

ASME H

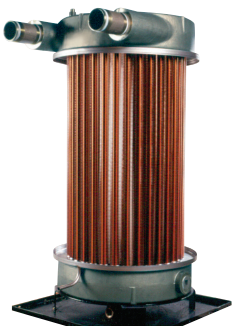
c UL US

THERMAL® SOLUTIONS

Innovative Equipment for Hot Water Systems

Thermal Solutions designed its Evolution high efficiency copper-fin tube boiler to meet the complexities of today's building systems. For nearly two decades, the Evolution boiler has been the industry benchmark for quality, reliability, and performance.

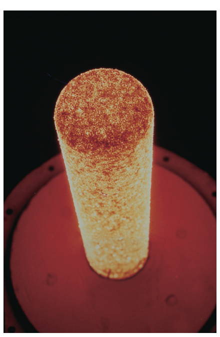
The Evolution takes copper-fin tube boiler technology to the next level by incorporating a list of unique design features. These include rugged heat exchanger design, advanced maintenance-free combustion and ease of installation and service. **The Evolution boiler truly is a step above the rest!**



Heat Exchanger

Rugged Heat Exchanger Design

Central to the boiler's design is its heat exchanger, which boasts twice as much heating surface than our competition. The rolled copper fin-tube, patent H/F Trufin is extruded from a solid piece of copper, resulting in a high quality component, and unsurpassed heat transfer. The gasket-less header design allows for easy inspection, cleaning, and individual tube replacement. Completely enclosed in a stainless steel compartment, the combustion chamber effectively handles short-term condensing periods (cold start) to protect the boiler. The Evolution heat exchanger has thicker tubes (.072") and more robust heads than any other hot water boiler product (compare the weights), making it very forgiving, more durable, and built to last!



Ceramic Radiant Burner

Advanced Maintenance-Free Combustion

The ceramic radiant burner never requires inspection or maintenance! Designed to operate with NOx emissions less than 10 ppm, the whisper-quiet burner (<50 dBA) runs at minimal excess air levels providing high efficient, trouble-free operation. The burner features a larger surface area and lower flux that allows for higher heat transfer and more uniform heating that extends the life of the copper tubes. A rugged cast-aluminum blower assembly, fitted with a replaceable combustion air filter that is 99% efficient to one micron, is used to keep the burner free of contaminants. A commercial-grade microprocessor based flame safeguard with LED diagnostic display, proven spark ignition and a UV flame scanner complete the Evolution's unsurpassed combustion system for safety and reliability. The Evolution boiler can be operated with its jacket panels removed during inspection to avoid nuisance problems associated with pressurized compartments.

Ease of Installation and Service

All rear connections and complete front and rear access to the unit's components, permitting space-saving side-by-side modular arrangements. The Evolution's flexible venting options include sealed or room air combustion, direct vent or conventional venting for multiple boiler common stack arrangements. Quick setup and low maintenance make the Evolution boiler an ideal choice for either retrofit or new construction projects.

EVOLUTION® FEATURES

Wide range of sizes

500,000–3,000,000 BTU/HR

Commercial-grade microprocessor based flame safeguard

Provides combustion management and safety

Heavy 16-gauge negative pressure steel jacket

Protects the boiler and eliminates nuisance problems associated with pressurized compartments

Gasketless header design

Allows for easy tube inspection and cleaning

Thick tubes (0.72") and robust headers

Provide durability

Vertical two-pass copper-fin tube configuration

Provides symmetrical heating for improved heat transfer

Small footprint (6 sq. ft / 11 sq. ft.)

For space-saving multiple unit installation

All rear connections

Allows minimal side-to-side clearances

Replaceable combustion air filter 99% efficient to one micron

Ensures burner reliability and trouble-free maintentance

Industrial cast- aluminum non-sparking blower assembly

Contributes to whisper-quiet (<50 dBA) operation

Fully water-backed tube sheet and unmatched fireside heating surface

(6.6 sq.ft. / 9.7 sq. ft to boiler horsepower) provides longevity

Flexible venting options

Include sealed or room air combustion, direct vent, or conventional venting

Non-corroding ceramic radiant burner with no moving parts

NOx emissions less than 10 PPM

Combustion chamber enclosure

Stainless steel material protects against corrosive flue gases

UL® Certified

Meets stringent test requirements

Pressure Vessel Design
- Copper fin-tube construction
- Carbon steel or cast iron header design
- Gasketless heat exchanger
- ASME Section IV certified "H" stamp
- MAWP 160 PSIG 240°F & max temp 250°F
- Five year heat exchanger warranty
- 20-year thermal shock warranty

Combustion Design
- Ceramic radiant burner, non-corroding
- Maintenance-free burner design
- Ultra-low NOx emissions (to <10 ppm)
- Whisper-quiet operation (<50 dBA)
- Combustion air filiter, 99% efficient
- Industrial cast aluminum blower assy.
- Variable frequency drive (modulation only)
- Electric spark-to-pilot ignition system
- 10-year burner warranty

Boiler Equipment
- SIemens RWF-40 operating control (modulation only)
- High limit w/manual reset safety temperature control
- Water flow switch
- Low water cuf-off w/manual reset safety controller
- Outlet temperature sensor
- Combustion air switch
- Pressure and temperature gauge
- Safety relief valve (available settings 30 to 150 PSI)
- Single point electrical supply (available in 1 or 3 phase)

Venting
- Sealed or room air combustion
- Direct vent (sidewall or vertical) up to 50 feet (Cat IV)
- Conventional venting (Cat II)

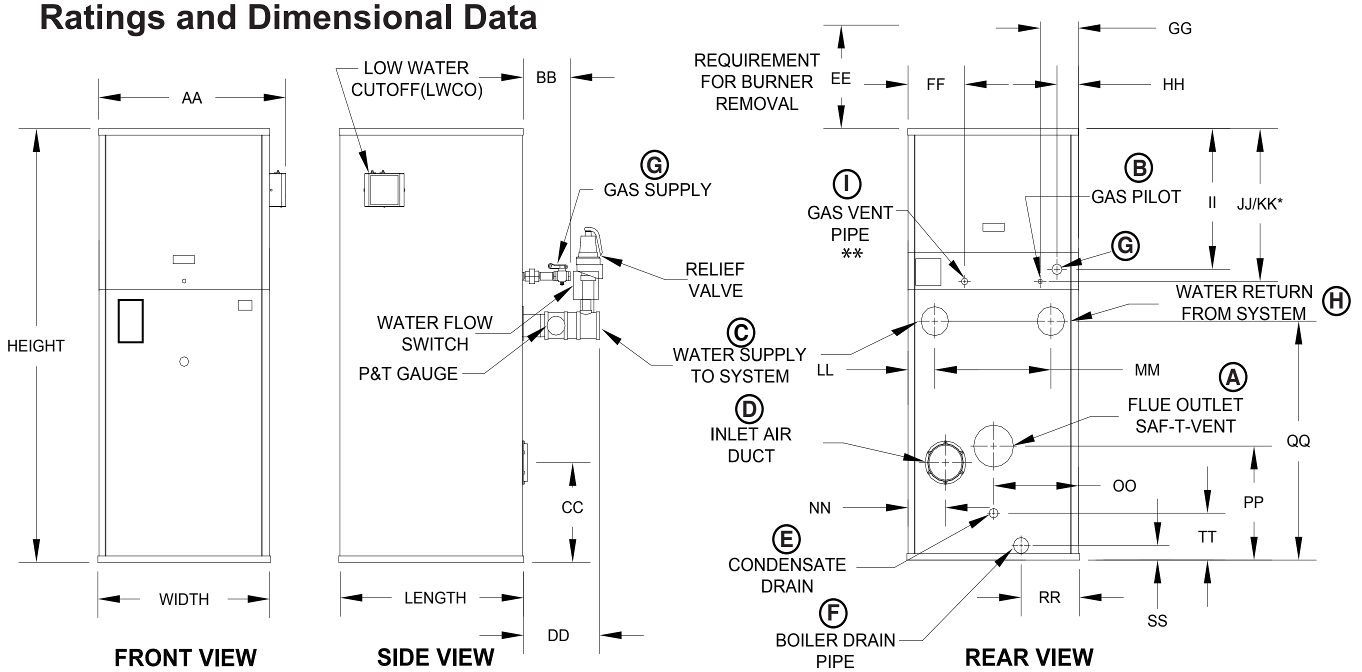
Burner Equipment
- UL/FM/CSD-1 gas train
- On-off or full modulation with infiinte proportional firing
- Natural or LP gas
- Inlet gas pressure available from 4" wc to 5 psig
- Pilot gas valve
- Pilot gas regulator
- Pilot/leak test cocks
- Main gas valve
- Low & high gas pressure switches w/manual reset

Siemens RWF40 Operating Control Features (modulation only)
- Adjustable set point
- Remote set point (0-10v or 4-20 mA)
- Outdoor air temperature reset
- Remote system temperature

EVOLUTION®

Higher Efficiency Heating Equipment

Ratings and Dimensional Data



* GAS PILOT DIMENSION ON MODELS 2000S, 2500,& 3000 ONLY
** DB&B AND DB&B WITH PROOF OF CLOSURE OPTION ONLY

Boiler Ratings (AHRI CERTIFIED® www.ahridirectory.org)				Dimensions and Specifications														
Model	Input MBH	Gross Output MBH	Net Ratings Water MBH*	SQ.Ft Per BHP	Footprint			Rear Connections									Shipping Wt. (lbs.)
					Height	Width	Depth	A	B	C	D	E	F	G	H	I	
EVA-500	500	431	375	9.4	71.2	28.3	30.3	4.0	1/4	2.0	4.0	5/8	1.0	1.0	2.0	3/4	772
EVA-750	750	623	542	6.6	60.9	28.3	30.3	4.0	1/4	3.0	6.0	5/8	1.0	1.0	3.0	3/4	1,097
EVA-1000	1,000	819	712	6.7	67.3	28.3	30.3	6.0	1/4	3.0	6.0	5/8	1.0	1.5	3.0	3/4	1,185
EVA-1500	1,500	1,251	1,088	6.7	79.4	28.3	30.3	6.0	1/4	3.0	8.0	5/8	1.0	1.5	3.0	3/4	1,327
EVA-2000	2,000	1,696	1,475	6.7	91.8	28.3	30.3	6.0	1/4	3.0	8.0	5/8	1.0	1.5	3.0	3/4	1,461
EVA-2000S	2,000	1,732	1,506	9.6	70.5	38.1	40.1	6.0	1/4	4.0	8.0	5/8	1.0	1.5	4.0	3/4	1,835
EVA-2500	2,500	2,170	1,887	9.7	77.5	38.1	40.1	8.0	1/4	4.0	8.0	5/8	1.0	2.0	4.0	1.0	2,052
EVA-3000	3,000	2,610	2,270	9.7	84.5	38.1	40.1	8.0	1/4	4.0	8.0	5/8	1.0	2.0	4.0	1.0	2,193

Model	AA	BB	CC	DD	EE	FF	GG	HH	II	JJ	KK	LL	MM	NN	OO	PP	QQ	RR	SS	TT
EVA-500	31.0	10.0	14.4	10.8	16.0	9.3	6.3	3.5	21.8	23.6	23.6	8.1	11.3	5.5	14.1	17.1	41.1	13.3	2.4	6.1
EVA-750	31.0	8.8	15.4	11.8	16.0	9.3	6.3	3.5	21.8	23.6	23.6	4.4	19.0	6.1	13.9	17.9	30.6	9.6	2.3	7.0
EVA-1000	31.0	10.0	15.4	11.8	16.0	9.3	6.3	3.5	21.8	23.6	23.6	4.4	19.0	6.1	13.9	17.6	36.9	9.6	2.3	7.3
EVA-1500	31.0	10.0	27.4	11.8	19.0	9.3	6.3	3.5	21.8	23.6	23.6	4.4	19.0	6.1	13.9	17.9	49.0	9.6	2.3	7.0
EVA-2000	31.0	10.0	27.4	11.8	31.0	9.3	6.3	3.5	21.8	23.6	23.6	4.4	19.0	6.1	13.9	17.9	61.4	9.6	2.3	7.0
EVA-2000S	40.8	10.5	19.6	13.3	13.0	4.0	8.5	5.0	20.9	22.4	23.4	5.9	26.2	7.0	19.0	18.6	39.6	14.4	2.2	6.9
EVA-2500	40.8	11.5	19.6	13.3	20.0	4.0	8.5	5.0	20.9	22.4	23.4	5.9	26.3	7.0	19.0	18.6	46.6	14.4	2.2	6.9
EVA-3000	40.8	11.5	19.6	13.3	26.5	4.0	8.5	5.0	20.9	22.4	23.4	5.9	26.2	7.0	19.0	18.6	53.6	14.4	2.2	6.9

*Net water ratings shown are based upon an allowance of 1.15. Dimensions are shown in Inches
The manufacturer should be consulted before selecting a boiler for installations having unusual piping and pickup requirements, such as intermittent system operation, extensive piping systems, etc. The ratings have been determined under the provisions governing forced draft boiler-burner units.

PL81467601050-

P.O. Box 3244, Lancaster, PA 17604-3244
Telephone: 717-239-7642, Fax: 877-501-5212
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Item # EVA-2000, Evolution (EVA) - High Efficiency Hot Water Boilers - Modulating, Indoor

Evolution (EVA) - High Efficiency Hot Water Boilers - Modulating, Indoor

Thermal Solutions has designed the Evolution® high efficiency copper-finned boilers to meet the needs of today's commercial heating requirements.

The Evolution takes the very best of existing copper-finned boiler technology to the next level by incorporating a list of design features not found in competitors' products. *Real-life serviceability, innovative heat exchanger design, clean and efficient advanced combustion, and unique timesaving controls* are all combined in a compact, quick-connect package with efficiencies of up to 87%. The Evolution is truly a step above the rest.

Real-Life Serviceability
The Evolution is adaptable to virtually any installation. Rear connection ports and complete front and rear access to the unit's components and controls simplify side-by-side modular applications. When venting is a concern, the Evolution offers sealed (direct vent) and power vent options so the need to construct a costly chimney is eliminated. In addition, the easy setup and even easier maintenance make Evolution boilers ideal for either retrofit or new construction projects.

Innovative Heat Exchanger Design
Central to the Evolution's highly efficient operation is the design of its copper-tube heat exchanger. Not only does it efficiently maintain heat transfer, but the innovative gasketless header allows easy inspection, cleaning and individual tube replacement. The combustion chamber is also completely enclosed in a stainless steel compartment and features collection/evaporation components to effectively handle cold-start condensate. Combining these features, the Evolution offers state-of-the-art heat transfer properties while effectively dealing with start-up condensate.

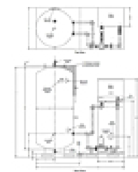
Clean and Efficient Advanced Combustion
Designed to operate at up to 87% thermal efficiency with NOx ratings less than 10 ppm, the Evolution's noiseless ceramic radiant burner runs at minimal excess air levels creating highly efficient, trouble-free operation. The rugged, industrial-cast-aluminum blower and fan wheel are equipped with a replaceable combustion air filter (99% efficient to one micron) to create excellent combustion characteristics and even air distribution. There's no need for tricky pressurized compartments...the Evolution can even be operated with its jacket panels removed for easy inspection or maintenance.

Unique Timesaving Controls
Instead of using a series of relays, the Evolution utilizes state-of-the-art microprocessor flame safeguard controls to provide extensive diagnostic information including first-out fault annunciation using an LED diagnostic display. The proven spark-to-pilot ignition system ensures that the pilot is lit before allowing the main gas valve to open. The optional display unit, as shown at the left, can be easily incorporated to provide additional operational information and history.

· SPECIFICATIONS · RATINGS AND DIMENSIONAL DATA · RATINGS & CAPACITIES · ELECTRICAL SUPPLY OPTIONS · ASME DESIGN DATA · TRIM & CONTROLS · DOUBLE BLOCK & BLEED (D.B.& B.) GAS TRAIN OPTION · D.B.& B. W/ P.O.C. GAS TRAIN OPTION · FIRING MODES · EVOLUTION® OUTDOOR MODEL · EVOLUTION HIGH EFFICIENCY DOMESTIC HOT WATER HEATING · HIGHLIGHTS · APPROVALS

SPECIFICATIONS

MBH Input	2,000 MBtu/hour
Elect. 1-Phase	120 208 230

Elect. 3-Phase	208 230 460
On-Off	No
Modulating	Yes
Drawing	 Dimensional Drawing for Evolution - High Efficiency Hot Water Boilers - On/Off and Modulating, Indoor, Storage Tanks/Skid

RATINGS AND DIMENSIONAL DATA

Input: BTUH	2,000,000 Btu/hr
Output: BTUH	1,696,000 Btu/hr
Sq. Ft. per BHP	6.9 ft²
Width: "A"	28.25 in 717.55 mm
Depth: "C"	30.25 in 768.35 mm
Height: "B"	91.813 in 2332.04 mm
Gas Connection: NPT	1-1/2 in
Water Connections: NPT	3 in
Air Inlet Connection	8 in 203.2 mm
Vent Connection	6 in 152.4 mm
Shipping Weight	1461 Pound

RATINGS & CAPACITIES

Boiler	50.7 hp 497 kW
Fuel	Natural Gas Propane

Input - High Fire	2,000,000 Btu/hr
Output - High Fire	1,760,000 Btu/hr
Inlet Gas Pressure (NG)	5 PSI Max. 9" W.C. Min.
Inlet Gas Pressure (LP)	2 PSI Max. 9" W.C. Min.
Operating Weight	1615 lb 733 kg

ELECTRICAL SUPPLY OPTIONS

Electrical Supply Options (Modulating)	120v/1ph/60hz - 7.5 Amps 208v/1ph/60hz - 6.6 Amps 230v/1ph/60hz - 6.4 Amps 208v/3ph/60hz - 6.0 Amps 230v/3ph/60hz - 6.0 Amps 460v/3ph/60hz - 3.0 Amps

ASME DESIGN DATA

ASME Design Data	Max. 160 PSIG &250ºF

TRIM & CONTROLS

Trim &Controls	Blower Motor, 1-1/2 HP Combustion Air Switch Flame Safeguard High Temperature Limit High/Low Gas Press Switches LWCO Flow Switch Modulating Gas Valve Operating Control Pilot Gas Regulator Pilot Gas Valve Pilot/Leak Test Cocks Pressure &Temperature Gauge Relief Valve VFD

DOUBLE BLOCK & BLEED (D.B.& B.) GAS TRAIN OPTION

Double Block &Bleed (D.B.& B.) Gas Train Option	(1) Motorized &(1) Solenoid Gas Valves N.O. Vent Valve

D.B.& B. W/ P.O.C. GAS TRAIN OPTION

IRI W/ P.O.C. Gas Train Option	(2) Motorized Gas Valves with proof of closure switches Flame Safeguard that recognizes proof of closure valves N.O. Vent Valve

FIRING MODES

Evolution boilers are available in Full Modulation.
Full modulation is achieved using a VFD and an air-fuel ratio modulating control valve. The control valve is actuated by an air signal from the fan - as the fan varies so does the gas valve. It is truly a linkage-less system and allows for safe fuel-air combustion. The full modulation uses a digital operating controller for infinitely proportional firing. Full modulation is available in models 500-3000 MBH input.

The Evolution boiler is available as a single or multi phase electric input, both 50 and 60 hertz. With no requirement for step-down transformers, the Evolution package comes complete and ready for single point electrical connection.

EVOLUTION® OUTDOOR MODEL

A specially designed, fully UL-approved outdoor jacket enclosure allows outdoor placement and all-weather operation.

In a response to industry demand, the Evolution outdoor unit enters the scene with the same robust design as the superior indoor model. The Evolution outdoor boiler is also designed to operate with NOx ratings as low as 10 ppm. Manufactured in five sizes from 500,000 to 2,000,000 BTU, the outdoor unit is available in on/off and full modulation firing modes. It is also available in both single and three-phase voltages. The outdoor model occupies the same footprint as the indoor unit, and its specially designed, fully UL-approved outdoor jacket enclosure allows outdoor placement and all-weather operation with lockable panel.

EVOLUTION HIGH EFFICIENCY DOMESTIC HOT WATER HEATING

Get advanced Evolution high-efficiency heating technology in a factory-assembled Packaged Water Heater System. Available in direct and indirect designs, each comes complete with storage tank, pump, and controls to serve as your single-source solution for domestic water heating needs.

HIGHLIGHTS

- Efficiencies up to 87%
- Ultra-low NOx levels below 10 ppm; meets or exceeds the most stringent emission requirements in the United States
- CO less than 50 ppm
- Quiet operation (• Maintenance-free ceramic radiant burner design
- Gasketless header design; minimizes the potential for leaks
- High quality copper-finned tubes extruded from solid copper piping; wall thickness is the best in the industry at 0.072"
- Copper tubes are individually accessible for cleaning or inspection and replaceable to eliminate the need for whole heat exchanger replacement
- Standard UL/FM/CSD-1 gas train; optional DB&B or IRI with POC gas train
- Single-point electrical hook-up for all voltage options (120-208-230/1/60 and 208-230-480/3/60)
- Multiple relief valve settings (30, 50, 60, 75, 100, 125 and 150 psig)
- Gas pressures range from 4" wc up to 5 psig
- Electric spark-to-pilot-ignition system
- Aluminum non-sparking fan assembly
- Inlet air filter 99% efficient to 1 micron
- Non-proprietary parts
- Jacket design lends itself to complete access to all components for easy serviceability
- Quick-connect compact package; maximum footprint is 6 sq/ft
- Sealed combustion or room air ready
- Reduced stack sizes - multiple venting options: sealed, direct and conventional
- Factory fire-test on every unit

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Appendix D-Manufacturer's Information for New Dust Filters

Donaldson
Torit®

TORIT® POWERCORE® DUST COLLECTORS
CP SERIES

PowerCore®

SMALLER. SMARTER COLLECTORS.

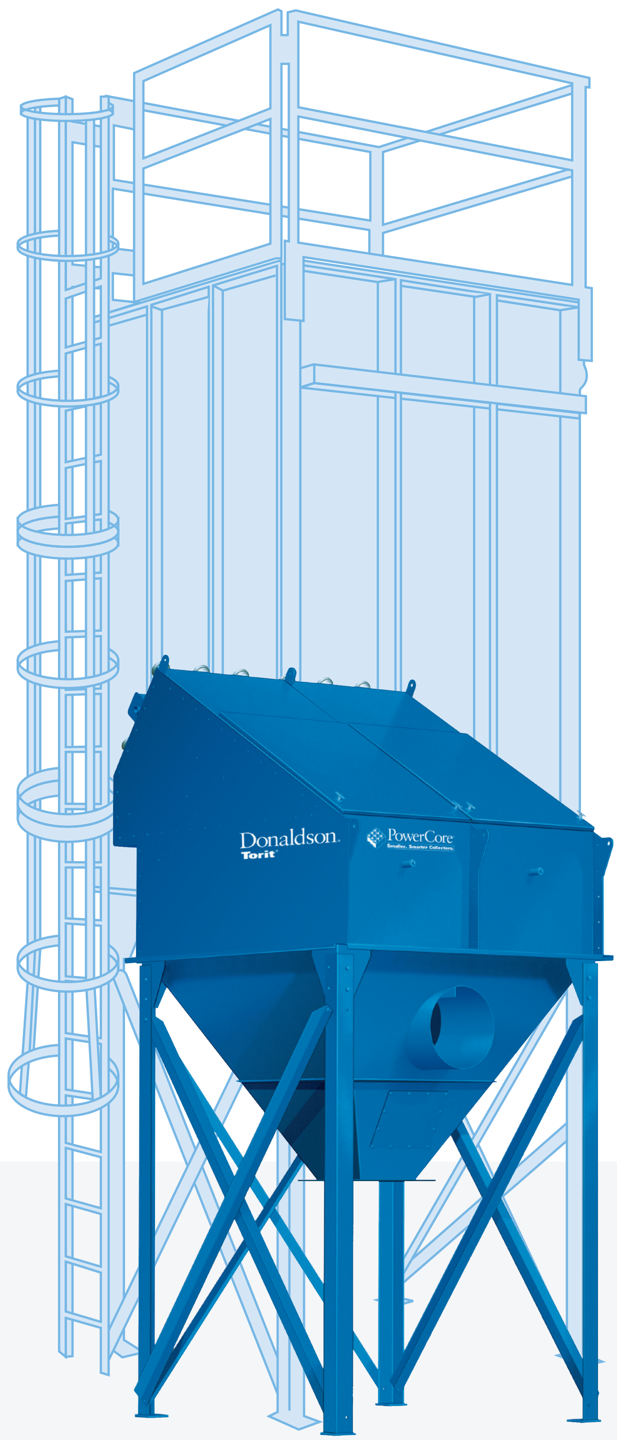
Torit® PowerCore® dust collection technology from Donaldson® Torit® outperforms traditional baghouse collectors and does so in less space. In one extremely small and powerful package, the Torit PowerCore dust collector handles high airflow, high grain loading, challenging particulate and fits into the smallest places. The filter changeout is remarkably quick, easy and clean compared to the process for traditional bag filters.

Innovative Torit PowerCore dust collectors combine award-winning PowerCore filter packs with a new proprietary compact pulse cleaning system. This proprietary combination delivers high filtration efficiencies not usually found in baghouse filtration.

TORIT POWERCORE

- **SMALLER**
- **SMARTER**
- **CLEANER**
- **EASIER**
- **COST EFFECTIVE**

UP TO 50% SMALLER THAN TRADITIONAL BAGHOUSE COLLECTORS



Torit PowerCore CPC-12
vs.
Traditional (81) 8-ft. filter baghouse
5000 cfm (8493 m³/h) collectors

OUTPERFORMS TRADITIONAL BAGHOUSE COLLECTORS

Today's streamlined and lean manufacturing facilities demand peak performance even within the smallest spaces. Torit PowerCore space-saving dust collectors are available as stand-alone models that can be ducted to many different applications, as well as bin vent models used on applications like silos, conveyor transfer points, conveyor discharges, blenders and mixers.

Compared to traditional baghouse collectors with similar airflow capacities, Torit PowerCore CPC dust collectors (as shown on previous page) are up to 50% shorter. The comparison to traditional bag-style bin vents is even more dramatic. CPV bin vent collectors are almost 70% shorter than other bag-style bin vents and effectively address the frequent challenge of tight space limitations.

SMALLER

Bin vents fit into the tightest spaces

CLEANER

PowerCore filter packs with Ultra-Web® technology provide higher efficiency for cleaner air. Plus, replacing PowerCore filter packs is a remarkably clean process

EASIER

Clean-side filter access and fewer, lighter filters means faster, easier filter changes without tools or filter cages

SMARTER

An optimized airflow management system delivers optimal pulse cleaning while minimizing airflow restriction

COST EFFECTIVE

Innovative PowerCore filtration technology means reduced freight and installation costs, fewer filter changeouts, lower maintenance costs, and no entry requirements for filter changes

UP TO 70% SMALLER THAN TRADITIONAL BIN VENT COLLECTORS

Torit PowerCore CPV-3
vs.
Traditional bin vent
1500 cfm (2548 m³/h) collectors

SMALLER. SMARTER FILTERS.

POWERCORE FILTER PACK—NOT A BAG, NOT A CARTRIDGE

An entirely new approach to dust collectors, the PowerCore filter pack is small, lightweight, and easily handled by one person. Donaldson's PowerCore technology allows more effective filter area to be packaged in a smaller space: one 7″ x 22″ (178 x 559 millimeters) PowerCore filter pack contains as much filtering area as 6 eight-foot-long (2.4 meters) traditional filter bags. And the filter media inside PowerCore filter packs is our well-proven Ultra-Web advanced nanofiber technology.

POWERCORE FILTER PACK

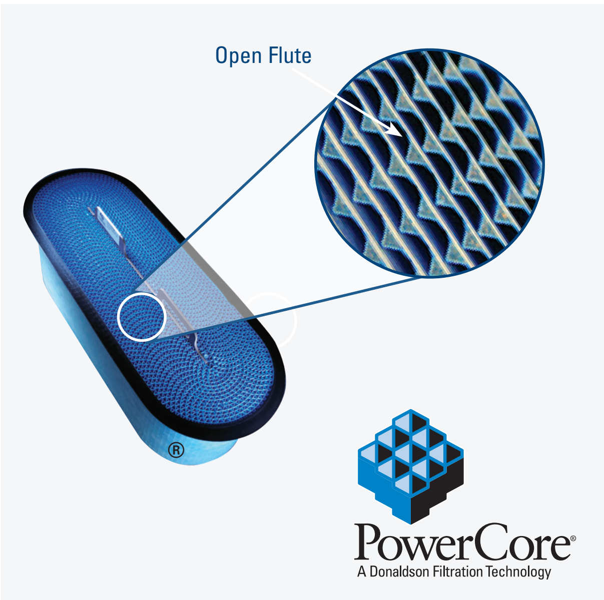
- Changeout from the clean side of the collector — only 1 person required
- Self-centering with a handle for easy changes without tools
- Integrated gasket ensures a good seal with every change
- At only 7″ tall, bridging is not a problem

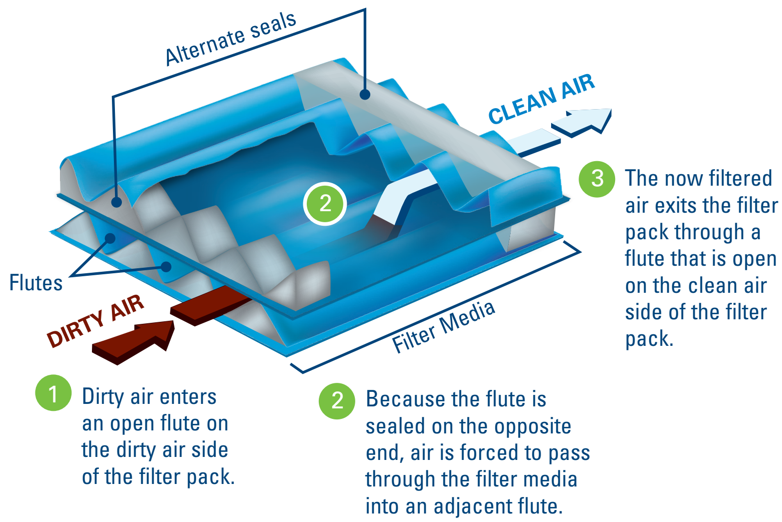
PowerCore®

INNOVATIVE MEDIA TECHNOLOGY

LEADING THE WAY WITH POWERCORE

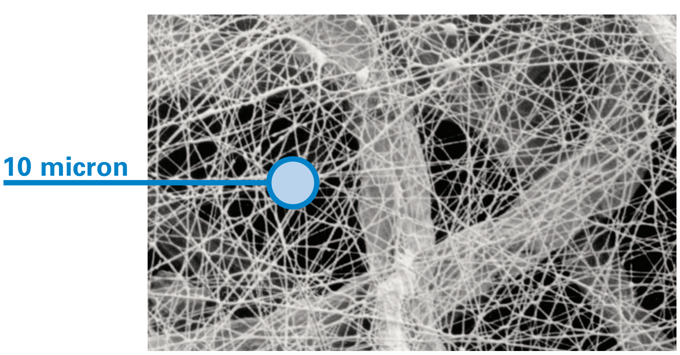
At the Core is PowerCore. PowerCore filter packs combine proprietary Ultra-Web nanofiber technology with Donaldson's media configuration expertise. The result is a revolutionary filtration technology unlike anything else in the industrial filtration market.



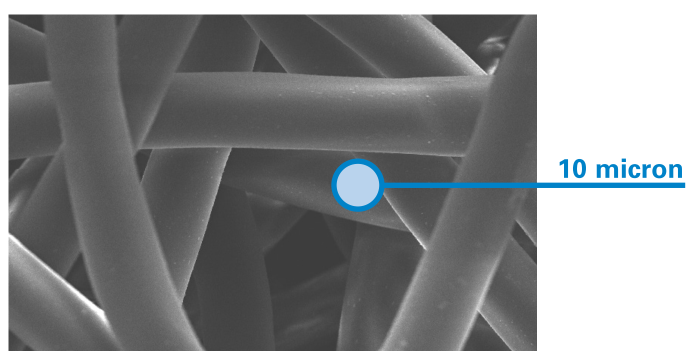


HIGH PERFORMANCE FILTER MEDIA

In a dramatic departure from the traditional filter bag, the PowerCore filter pack contains Ultra-Web media, which traps more dust on the surface of the fluted channels as compared to conventional bag filter materials like depth-loading 16 oz. (453.6 g) polyester. Surface loading greatly promotes filter cleaning. Better pulse cleaning lowers operational pressure drop and energy use.



Ultra-Web Nanofiber Technology
(600x)

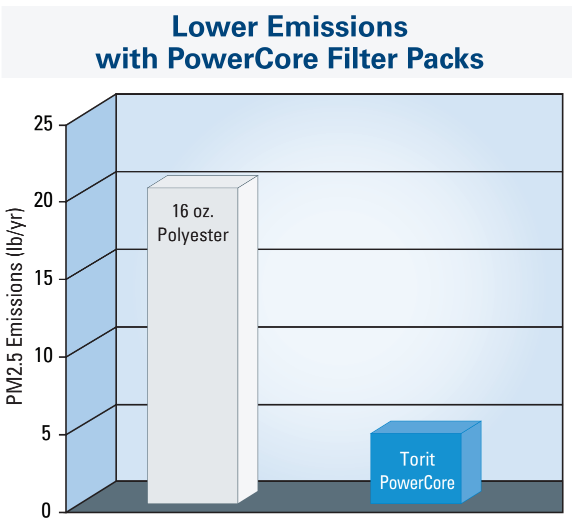


16 oz. (453.6 g) Polyester
(600x)

POWERCORE FILTER PACKS – ENGINEERED TO PERFORM

TECHNOLOGY THAT PERFORMS FOR OVER 25 YEARS

Donaldson Torit Ultra-Web technology has delivered high efficiency filters that last. PowerCore filter packs with Ultra-Web are engineered to perform, balancing high efficiencies with long filter life.



Independent lab results obtained using ASTM D6830-02 per EPA PM 2.5 performance verification. Annual emissions calculated assuming 14,400 cfm (24,461 m³/h) airflow rate, 265 working days per year, and two shifts per day. Field measurements may vary due to differences in dust contaminant and sensitivity of measurement equipment.

OUTSTANDING PERFORMANCE

Torit PowerCore CP Series systems with PowerCore filter packs deliver outstanding performance with PM 2.5 emissions below 0.001 grains per cubic foot, per EPA Method 27 and EPA Method 5i.

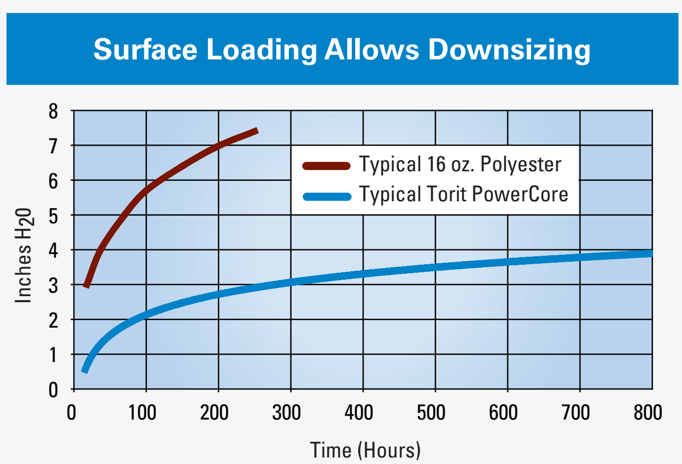
Torit Powercore CP Series filter packs are efficiency rated MERV15 per the ASHRAE 52.2-2007 test standard.

78% FEWER EMISSIONS | **MERV 15**

EASY ON THE BUDGET

The surface-loading technology of Ultra-Web is proven to provide lower operating pressure drop over a longer period of time, and energy costs can be dramatically reduced. Pressure drop starts high and rises quickly with traditional depth-loading bag filters, resulting most often in excessive energy use.

For proven technology that delivers savings in energy, maintenance, space, and filter changes, the smartest solution is Torit PowerCore.



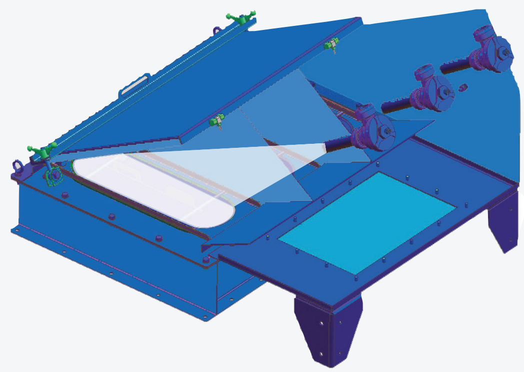
The results from accelerated lab and field tests show that Torit PowerCore can provide lower pressure drop in baghouse applications.

OPTIMIZED AS A SYSTEM

SMARTER FILTER CLEANING

Torit PowerCore collectors include a new proprietary compact pulse cleaning system designed to match the pulse energy to the obround shape of the PowerCore filter pack. The resulting pulse flow effectively covers the entire media pack. It easily pulses the dust out of the fluted channels, keeping the pressure drop low and prolonging filter life.

Compact Pulse Cleaning System CPV-1



Compact Oblique Pulse Cleaning System
CPV-2 THROUGH CPV-12

SOPHISTICATED MODELING

Providing optimized pulse cleaning, the pulse accumulator design is based on Donaldson Torit's commitment to technical research and development. FLUENT®* Airflow Modeling Software was used to determine the shape of the pulse accumulators to optimize the pulse energy without restricting the airflow or wasting energy. The pulse accumulators also serve as a filter retention mechanism, securing the filter pack in place and ensuring optimum gasket compression.

Pulse Accumulator
Optimizes Pulse & Seals Filter Pack

* FLUENT is a registered trademark of Fluent, Inc.

MAKING MAINTENANCE EASIER

SMALLER, BETTER, SMARTER

Torit PowerCore can reduce your cost of dust collection resulting in significant operational savings. An application previously requiring (81) 8-foot (2.4 meter) bag filters now needs only (12) 7-inch-tall (177.8 mm) PowerCore filter packs. Fewer filters mean lower filter changeout costs and faster changeouts. The smaller collector means lower installation costs and less factory floor or bin space consumption.

	# of Filters in Collector	Time to Replace*	Labor Cost	Time Savings*	Labor Savings*
PowerCore Filter Packs	12	**ONLY 24 minutes**	$18	**13.1 hours**	**$590 SAVED**
Traditional Bag Filters	81	13.5 hours	$608	0	0

* Savings are based on one changeout. Calculations assume bags and PowerCore filter packs show equal life span; one person replacing one traditional bag filter in 10 minutes; one person changing PowerCore in 2 minutes; labor rates equal $45/hr.

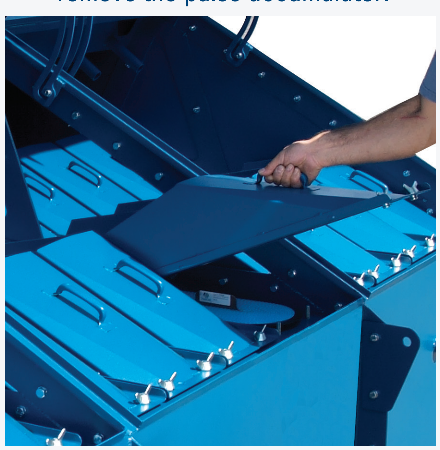
EASY MAINTENANCE

Replacing PowerCore filter packs is as easy as 1-2-3. Contrary to many traditional baghouse collectors, PowerCore filter packs are lightweight and accessed from the clean side of the collector.

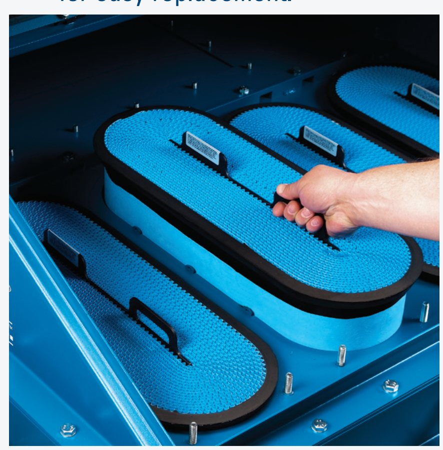
POWERCORE FILTER PACK REPLACEMENT — EASY. FAST. CLEAN. NO TOOLS OR CAGES REQUIRED.

1. Lift up filter access door. (Clean side of the system)

2. Loosen the captive hardware and remove the pulse accumulator.



3. Lift out the filter pack for easy replacement.



NO ENTRY REQUIRED

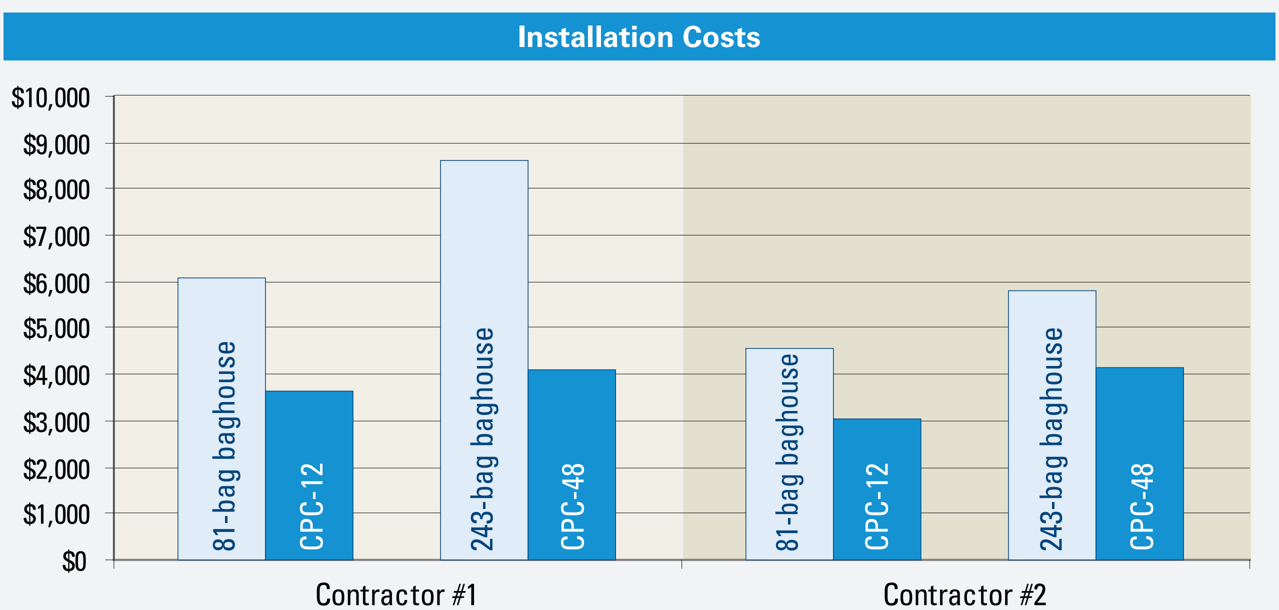
HOW SMALLER MEANS SMARTER OPERATION

SMART RESULTS IN MANY WAYS

- Collectors weigh less, so shipping costs are lower
- There are no bag filters or cages to ship and install separately
- Easier filter pack changeouts save time and money
- Airflow design prevents dust bridging between filter packs, creating less maintenance required
- Airflow patterns minimize abrasion, preventing leaks and maintenance common with abrasive dust

A CPV-2 is 70% smaller than a traditional bin vent making shipping easy and reducing freight costs.

UP TO 50% LOWER INSTALLATION COSTS



The Torit PowerCore system arrives mostly assembled, so installation is faster and easier. Installation costs are reduced 30-50% due to lighter weight, less crane time, and pre-assembly. The filter packs come pre-installed in the collector, so there are no bags or cages to install separately.

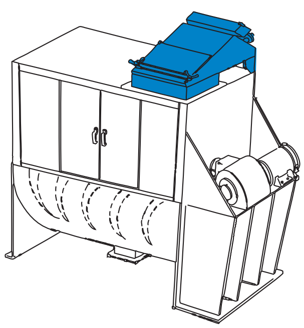
THE OPTIMIZED SOLUTION FOR MATERIAL HANDLING

SMARTER SOURCE FILTRATION

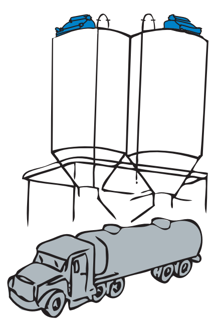
Torit PowerCore CPV bin vent collectors are easily integrated into a variety of material-handling applications—even in tight spaces—providing source filtration that saves money and energy.

SOURCE COLLECTION WITH TORIT POWERCORE CAN PROVIDE:

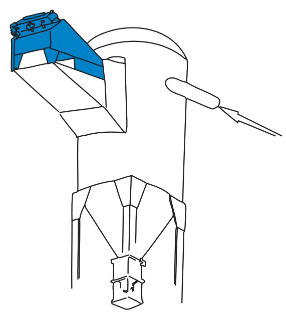
- Lower initial costs: freight, installation, and ducting are all reduced
- Reduced energy consumption as air and dust aren't moved unnecessarily through long ducting runs
- Product will stay in the process, eliminating waste streams and costly recycle systems



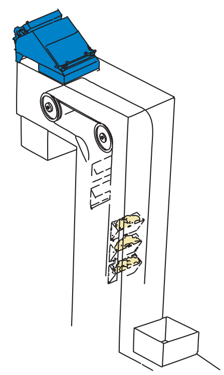
Blender/Mixer



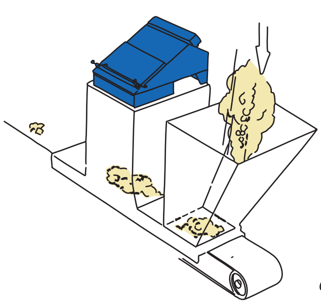
Silo/Bin Vent



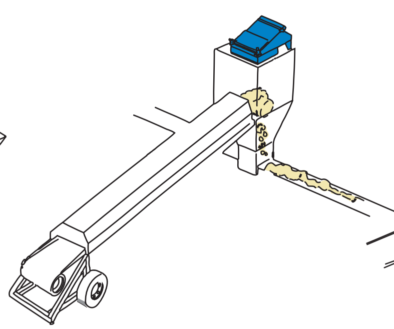
Pneumatic Receiver



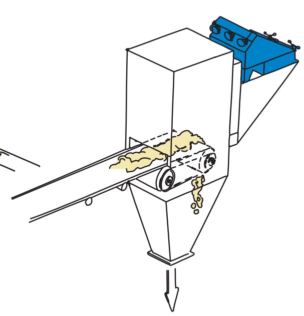
Bucket Elevator



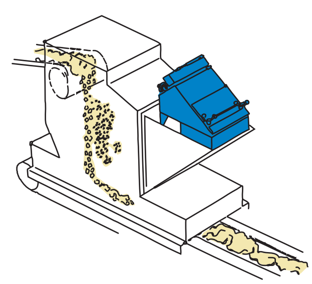
Chute-to-Belt



Tripper Conveyor



Conveyor Discharge

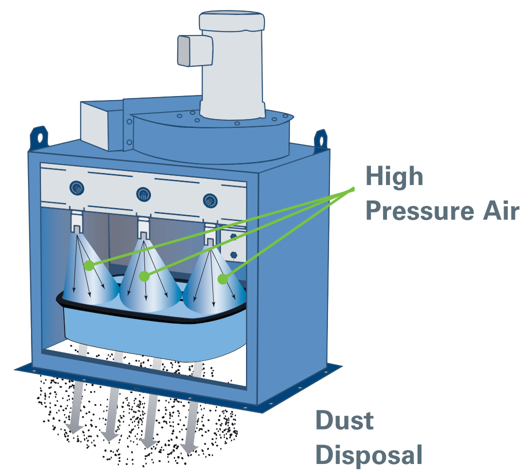


Conveyor Transfer

HOW THE CP SERIES WORKS

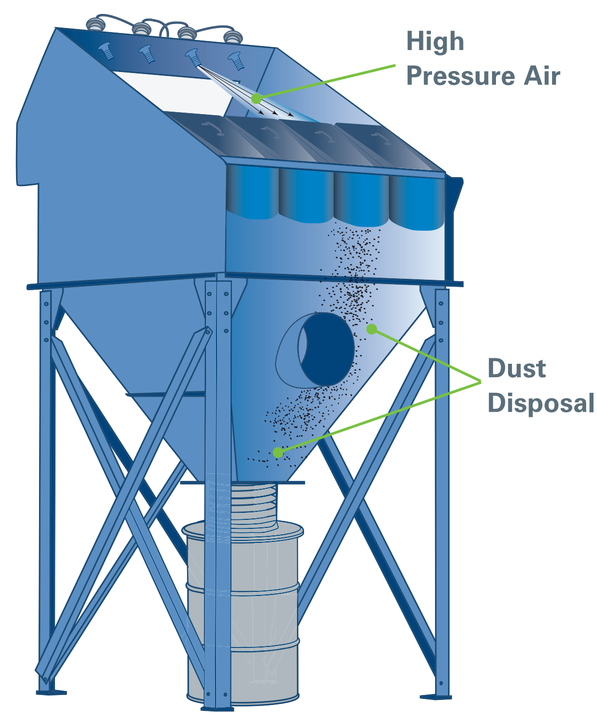
- Dust-laden air enters the collector through the dirty air inlet and is directed upward through the filter packs
- Heavier particulate falls directly into the hopper or bin below
- Air is filtered through the filter packs and directed out the clean air outlet
- When pressure drop exceeds a pre-set point, the compact pulse system sends a pulse of cleaning air back through the filter packs and thoroughly cleans the media flutes

NORMAL OPERATION
FOR CPV-1 MODEL



FILTER CLEANING OPERATION
FOR CPV-1 MODEL

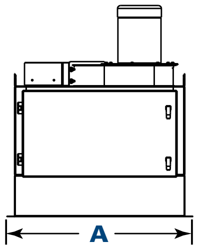
NORMAL OPERATION
FOR CPC-3 THROUGH CPC-48 MODELS



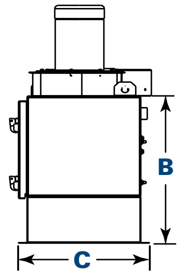
FILTER CLEANING OPERATION
FOR CPC-3 THROUGH CPC-48 MODELS

DIMENSIONS & SPECIFICATIONS

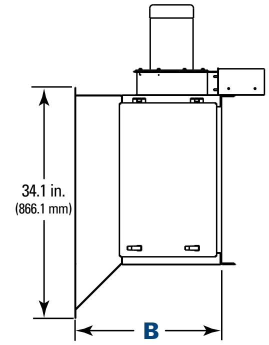
MODELS CPV-1



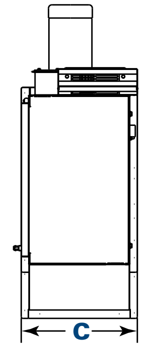
CPV-1
Front View



CPV-1
Side View

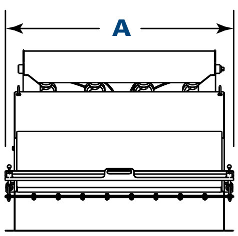


CPV-1
Vertical Front View

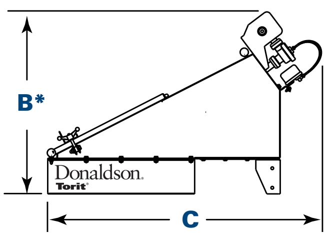


CPV-1
Vertical Side View

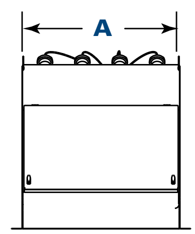
MODELS CPV-2 TO CPV-12



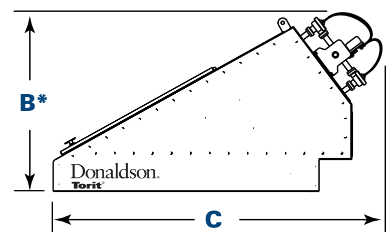
CPV-2, -3, -4
Front View



CPV-2, -3, -4
Side View



CPV-6, -8, -12
Front View



CPV-6, -8, -12
Side View

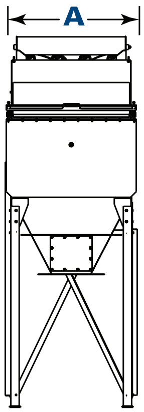
Model	Nominal Airflow Range**		No. of Filter Packs	PowerCore Filter Area		No. of Valves	Shipping Weight		Housing Rating ("wg)	Dimensions					
										A		B*		C	
	cfm	m³/h		ft²	m²		lb	kg		in	mm	in	mm	in	mm
CPV-1	up to 700	up to 1189	1	63	5.9	3	120†	54.4†	±12	28.0	711.2	22.3	566.4	17.6	447.0
CPV-2	450 - 1,400	764 - 2,378	2	126	11.7	2	290	131.5	±20	26.8	680.7	37.2	944.9	47.7	1,211.6
CPV-3	700 - 2,000	1,189 - 3,397	3	189	17.6	3	375	170.1	±20	36.8	934.7	37.2	944.9	47.7	1,211.6
CPV-4	1,400 - 2,700	2,378 - 4,586	4	252	23.4	4	460	208.7	±20	46.8	1,188.7	37.2	944.9	47.7	1,211.6
CPV-6	2,100 - 4,100	3,567 - 6,964	6	378	35.1	6	715	324.3	±20	38.0	965.2	46.1	1,170.9	83.6	2,123.4
CPV-8	2,800 - 5,400	4,756 - 9,173	8	504	46.8	8	800	362.9	±20	48.0	1,219.2	46.1	1,170.9	83.6	2,123.4
CPV-12	4,200 - 8,200	7,134 - 13,929	12	756	70.2	12	1290	585.1	±20	70.0	1,778.0	46.1	1,170.9	83.6	2,123.4

* For opening access door, allow a minimum of 2.5" (63.5 mm) above unit for models 2, 3, 4, and a minimum of 20.5" (520.7 mm) for models 6, 8, 12.
** Based on clean filters.
† Shipping weight with integral fan is 160 lbs. (72.6 kg)

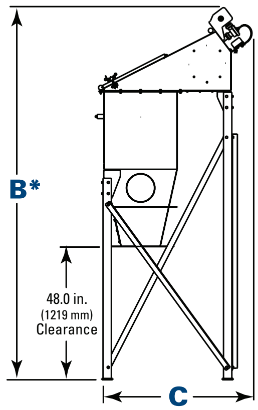
OPERATING CONDITIONS FOR CP SERIES COLLECTORS

Seismic Spectral Acceleration (at grade)	S_S +1.5 & S_1= 0.6	Compressed Air Required (psi/bar)	90-100/6.2-6.9
Wind Load Rating (mph/kph)	90/145	Operating Temperature	150°F/66 °C

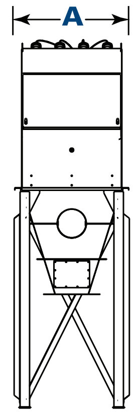
MODELS CPC-3 TO CPC-48



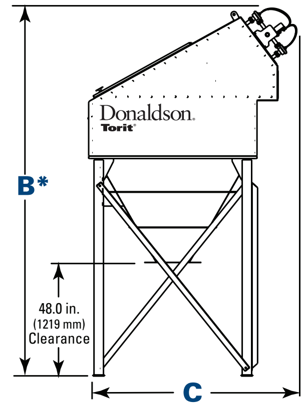
CPC-3, -4
Front View



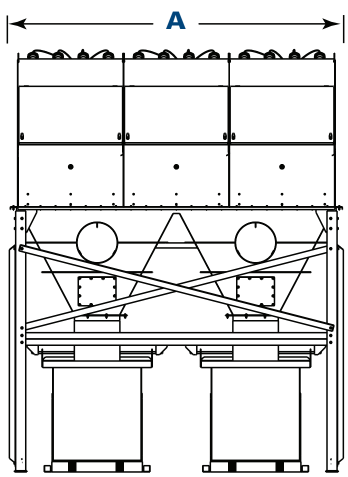
CPC-3, -4
Side View



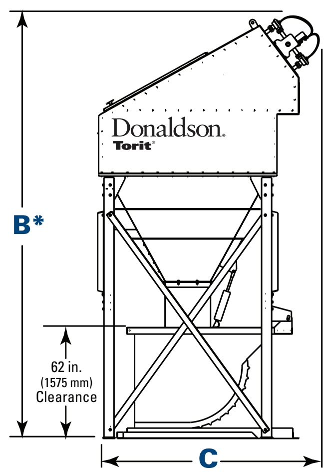
CPC-6, -8, -12, -16
Front View



CPC-6, -8, -12, -16
Side View



CPC-24 with optional dumpster hopper**
Front View

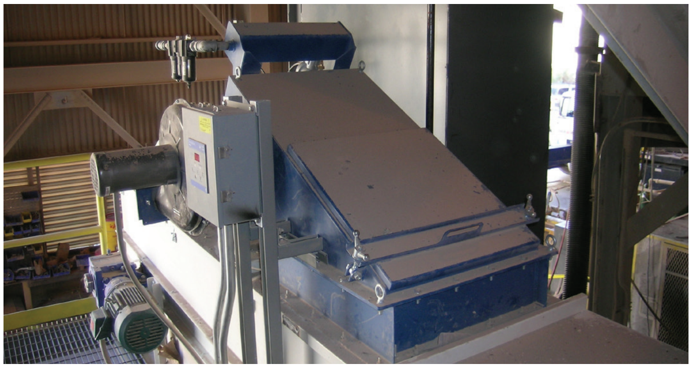


CPC-24 with optional dumpster hopper
Side View

	Nominal Airflow Range†		No. of Filter Packs	PowerCore Filter Area		No. of Valves	Shipping Weight		Housing Rating	Dimensions					
										A		B*		C***	
Model	cfm	m³/h		ft²	m²		lb	kg	(“wg)	in	mm	in	mm	in	mm
CPC-3	700 - 2,000	1,189 - 3,397	3	189	17.6	3	800	362.9	-20	36.8	934.7	118.4	3,007.4	55.5	1,409.7
CPC-4	1,400 - 2,700	2,378 - 4,586	4	252	23.4	4	1020	462.7	-20	46.8	1,188.7	134.2	3,408.7	55.5	1,409.7
CPC-6	2,100 - 4,100	3,567 - 6,964	6	378	35.1	6	1600	725.7	-20	38.6	980.4	154.2	3,916.7	85.0	2,159.0
CPC-8	2,800 - 5,400	4,756 - 9,173	8	504	46.8	8	1685	764.3	-20	48.5	1,231.9	154.2	3,916.7	85.0	2,159.0
CPC-12	4,200 - 8,200	7,134 - 13,929	12	756	70.2	12	2100	952.5	-20	70.0	1,778.0	154.2	3,916.7	85.0	2,159.0
CPC-16	5,600 - 11,000	9,512 - 18,685	16	1008	93.6	16	2915	1,322.2	-20	90.0	2,286.0	169.2	4,297.7	85.0	2,159.0
CPC-24	8,400 - 16,500	14,269 - 28,028	24	1512	140.5	24	3880	1,759.9	-20	132.0	3,352.8	152.2	3,865.9	85.0	2,159.0
CPC-32	11,200 - 22,000	19,025 - 37,370	32	2016	187.3	32	5310	2,408.6	-20	174.0	4,419.6	169.2	4,297.7	85.0	2,159.0
CPC-40	14,000 - 27,000	23,781 - 45,864	40	2520	234.1	40	6210	2,816.8	-20	216.0	5,486.4	154.7	3,929.4	85.0	2,159.0
CPC-48	16,800 - 33,000	28,537 - 56,055	48	3024	280.9	48	7760	3,519.9	-20	258.0	6,553.2	169.2	4,297.7	85.0	2,159.0

* For opening access door, allow a minimum of 2.5” (63.5 mm) above unit for models 3, 4, and a minimum of 20.5” (520.7 mm) for models 6, 8, 12, 16, 24, 32, 40, 48.
** CPC-24 through CPC-48 are available with optional pyramid hoppers, trough hoppers, or dumpster hoppers.
*** Standard hoppers. † Based on clean filters.

SMARTER PERFORMANCE ON MANY TYPES OF DUST



CPV-2 - Weigh belt feeder with limestone dust
800 cfm (1,359 m^3/h)

CPC-24 - Paper tissue manufacturing
7,600 cfm (12,910 m^3/h)

CPV-6 - Direct bin venting distributor head
2,400 cfm (4,077 m^3/h)

CPV-2 - Day bin with porcelain dust
800 cfm (1,359 m^3/h)

CPC-12 on Wood Dust at furniture manufacturer
7,000 cfm (11,891 m^3/h)

CPV-12 - Cement silo bin vent conveyor
3,700 cfm (6,285 m^3/h)

CPC-3 - Powdered milk dust in cheese factory
1,200 cfm (2,038 m^3/h)

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STANDARD FEATURES & AVAILABLE OPTIONS

TORIT POWERCORE CPC COLLECTORS

Collector Design	Std	Opt
Mild Steel Construction	✗	
Clean-Side Filter Pack Removal	✗	
Tool-Free Filter Removal	✗	
Hopper Access Panel	✗	
Sprinkler Taps	✗	
Mountable Fan Package (CPC-3 through CPC-24)		✗
Stainless Steel Construction		✗
Filter Packs		
PowerCore with Ultra-Web	✗	
PowerCore AS (Anti-Static) with Ultra-Web		✗
Paint System		
Textured Multi-Coat Paint Finish with 2,000-Hour Salt Spray Performance	✗	
Premium Duty Finish		✗
Custom Colors, Materials, and Finishes		✗
Pyramid Hopper Discharge Options		
Pyramid Hopper	✗	
Trough Hopper with High Inlet (CPC-16 through CPC-48)		✗
Dumpster Hopper (CPC-16 through CPC-48)		✗
Hopper Discharge		
Slide Gate Pack		✗
55-Gallon (208.2-Liter) Drum Covers		✗
Transitions for Rotary Valves		✗
Support Structure †		
48" (1219.2 mm) Clearance Beneath Hopper	✗	
Leg Extensions		✗
Electrical Controls, Gauges and Enclosures		
Control Box NEMA Type 4 with Timer	✗	
Solenoid Enclosure NEMA Type 4	✗	
Magnehelic®* Gauge	✗	
Delta P Control NEMA Type 4 with Timer		✗
Delta P Plus Control NEMA Type 4 with Timer		✗
Delta P Control (no timer)		✗
Solenoid Enclosure NEMA Type 9		✗
Heated Solenoid Pack		✗
Heavy Duty Cold Climate Kit		✗
Photohelic®* Gauge		✗
Custom Control Panels		✗
Safety Features		
Explosion Vents		✗
Sprinkler Pack		✗
Platforms and Ladders (CPC 16-48)		✗
Electrical Grounding and Bonding		✗
Warranty		
10-Year Warranty	✗	

TORIT POWERCORE CPV COLLECTORS

Collector Design	Std	Opt
Mild Steel Construction	✗	
Clean-Side Filter Pack Removal	✗	
Tool-Free Filter Removal	✗	
Mountable Fan Package		✗
Outlet Weatherhood		✗
Stainless Steel Construction		✗
Vertical Orientation		✗
Filter Packs		
PowerCore Ultra-Web® (MERV 15)	✗	
PowerCore Ultra-Web SB (Spunbond) (MERV 15)		✗
PowerCore Ultra-Web AS (Anti-Static) (MERV 15)		✗
Paint System		
Textured Multi-Coat Paint Finish with 2,000-Hour Salt Spray Performance	✗	
Premium Duty Finish		✗
Custom Colors, Materials, and Finishes		✗
Safety Features		
Electrical Grounding & Bonding		✗
Electrical Controls, Gauges and Enclosures		
Control Box NEMA Type 4 with Timer	✗	
Solenoid Enclosure NEMA Type 4	✗	
Magnehelic®* Gauge	✗	
Delta P Control NEMA Type 4 with Timer		✗
Delta P Plus Control NEMA Type 4 with Timer		✗
Delta P Control (no timer)		✗
Solenoid Enclosure NEMA Type 9		✗
Heated Solenoid Pack		✗
Heavy Duty Cold Climate Kit		✗
Photohelic®* Gauge		✗
Custom Control Panels		✗
Warranty		
10-Year Warranty	✗	

* Magnehelic and Photohelic are registered trademarks of Dwyer Instruments, Inc.

† Donaldson Torit equipment is designed to IBC guidelines for specific wind speed exposure and seismic spectral acceleration at grade level. Contact your Donaldson Torit representative for detailed information available on the equipment's Spec Control drawings. Equipment may be customized to meet unique, customer-specified site requirements.

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Appendix E- Emission Factor Support Information

E-1 EPA AP-42 Section 9.9.1
E-2 Donaldson Torit Filter Emission Guarantee
E-3 Pellet Mill Cooler PM Source Test- 4/27/2000
E-4 Kiln PM Source Test- 10/14/2005
E-5 EPA AP-42 Section 1.4
E-6 EPA AP-42 Section 3.3
E-7 LA Kiln SO2 Source Test- 5/20-21/1991
E-8 Maxon Burner Emission Certification
E-9 GV Boiler Emissions Information
E-10 Washington Kiln VOC Source Test- 8/25/1994
E-11 Ventura County APCD Natural Gas Emission Factors

E-1 EPA AP-42 Section 9.9.1

9.9.1 Grain Elevators And Processes

9.9.1.1 Process Description[1-14]

Grain elevators are facilities at which grains are received, stored, and then distributed for direct use, process manufacturing, or export. They can be classified as either “country” or “terminal” elevators, with terminal elevators further categorized as inland or export types. Operations other than storage, such as cleaning, drying, and blending, often are performed at elevators. The principal grains and oilseeds handled include wheat, corn, oats, rice, soybeans, and sorghum.

Country elevators are generally smaller elevators that receive grain by truck directly from farms during the harvest season. These elevators sometimes clean or dry grain before it is transported to terminal elevators or processors. Terminal elevators dry, clean, blend, and store grain before shipment to other terminals or processors, or for export. These elevators may receive grain by truck, rail, or barge, and generally have greater grain handling and storage capacities than do country elevators. Export elevators are terminal elevators that load grain primarily onto ships for export.

Regardless of whether the elevator is a country or terminal, there are two basic types of elevator design: traditional and modern. Traditional grain elevators are typically designed so the majority of the grain handling equipment (e.g., conveyors, legs, scales, cleaners) are located inside a building or structure, normally referred to as a headhouse. The traditional elevator often employs belt conveyors with a movable tripper to transfer the grain to storage in concrete or steel silos. The belt and tripper combination is located above the silos in an enclosed structure called the gallery or bin deck. Grain is often transported from storage using belt conveyors located in an enclosed tunnel beneath the silos. Particulate emissions inside the elevator structure may be controlled using equipment such as cyclones, fabric filters, dust covers, or belt wipers; grain may be oil treated to reduce emissions. Controls are often used at unloading and loading areas and may include cyclones, fabric filters, baffles in unloading pits, choke unloading, and use of deadboxes or specially designed spouts for grain loading. The operations of traditional elevators are described in more detail in Section 2.2.1. Traditional elevator design is generally associated with facilities built prior to 1980.

Country and terminal elevators built in recent years have moved away from the design of the traditional elevators. The basic operations performed at the elevators are the same; only the elevator design has changed. Most modern elevators have eliminated the enclosed headhouse and gallery (bin decks). They employ a more open structural design, which includes locating some equipment such as legs, conveyors, cleaners, and scales, outside of an enclosed structure. In some cases, cleaners and screens may be located in separate buildings. The grain is moved from the unloading area using enclosed belt or drag conveyors and, if feasible, the movable tripper has been replaced with enclosed distributors or turn-heads for direct spouting into storage bins and tanks. The modern elevators are also more automated, make more use of computers, and are less labor-intensive. Some traditional elevators have also been partially retrofitted or redesigned to incorporate enclosed outside legs, conveyors, cleaners, and other equipment. Other techniques used to reduce emissions include deepening the trough of the open-belt conveyors and slowing the conveyor speed, and increasing the size of leg belt buckets and slowing leg velocity. At loading and unloading areas of modern elevators, the controls cited above for traditional elevators can also be used to reduce emissions.

The first step at a grain elevator is the unloading of the incoming truck, railcar, or barge. A truck or railcar discharges its grain into a hopper, from which the grain is conveyed to the main part of the elevator. Barges are unloaded by a bucket elevator (either a continuous barge unloader or marine leg) that is extended down into the barge hold. The main building at an elevator, where grain is elevated and distributed, is called the “headhouse”. In the headhouse, grain is lifted on one of the elevator legs and, at older facilities, is typically discharged onto the gallery belt, which conveys the grain to the storage bins. A “tripper” diverts grain off the belt and into the desired bin. At more modern facilities, other modes of transfer include enclosed conveyors, direct spouting, augers, and screw conveyors. Grain is often cleaned, dried, and cooled for storage. Once in storage, grain may be transferred one or more times to different storage bins or may be emptied from a bin, treated or dried, and stored in the same or a different bin. The most common method for unloading ships is by leg, using either an in-house leg operated by the facility or a self-unloading system (leg and conveyors) designed into the vessel. Figure 9.9.1-1 presents the major process operations at a grain elevator.

A grain processing plant or mill receives grain from an elevator and performs various manufacturing steps that produce a finished food product. The grain receiving and handling operations at processing plants and mills are basically the same as at grain elevators. Examples of processing plants are flour mills, oat mills, rice mills, dry corn mills, and animal feed mills. The following subsections describe the processing of the principal grains. Additional information on grain processing may be found in AP-42 Section 9.9.2, Cereal Breakfast Food, and AP-42 Section 9.9.7, Corn Wet Milling.

9.9.1.1.1 Flour Milling[2,5] -

Most flour mills produce wheat flour, but durum wheat and rye are also processed in flour mills. The wheat flour milling process consists of 5 main steps: (1) grain reception, preliminary cleaning, and storage; (2) grain cleaning; (3) tempering or conditioning; (4) milling the grain into flour and its byproducts; and (5) storage and/or shipment of finished product. A simplified diagram of a typical flour mill is shown in Figure 9.9.1-2. Wheat arrives at a mill and, after preliminary cleaning, is conveyed to storage bins. As grain is needed for milling, it is withdrawn and conveyed to the mill area where it first enters a separator (a vibrating screen), then, an aspirator to remove dust and lighter impurities, and then passes over a magnetic separator to remove iron and steel particles. From the magnetic separator, the wheat enters a disc separator designed to catch individual grains of wheat and reject larger or smaller material and then to a stoner for removal of stones, sand, flints, and balls of caked earth or mud. The wheat then moves into a scourer which buffs each kernel and removes more dust and loose bran (hull or husk). Following the scouring step, the grain is sent to the tempering bins where water is added to raise the moisture of the wheat to make it easier to grind. When the grain reaches the proper moisture level, it is passed through an impact machine as a final cleaning step. The wheat flows into a grinding bin and then into the mill itself.

The grain kernels are broken open in a system of breaks by sets of corrugated rolls, each set taking feed from the preceding one. After each break, the grain is sifted. The sifting system is a combination of sieving operations (plansifters) and air aspiration (purifiers). The flour then passes through the smooth reducing rolls, which further reduce the flour-sized particles and facilitate the removal of the remaining bran and germ particles. Plansifters are used behind the reducing rolls to divide the stock into over-sized particles, which are sent back to the reducing rolls, and flour, which is removed from the milling system. Flour stock is transported from the milling system to bulk storage bins and subsequently packaged for shipment.

Generally, durum wheat processing comprises the same steps as those used for wheat flour milling. However, in the milling of durum, middlings rather than flour are the desired product. Consequently, the break system, in which middlings are formed, is emphasized over the part of the reduction system in which flour is formed. Grain receiving, cleaning, and storage are essentially

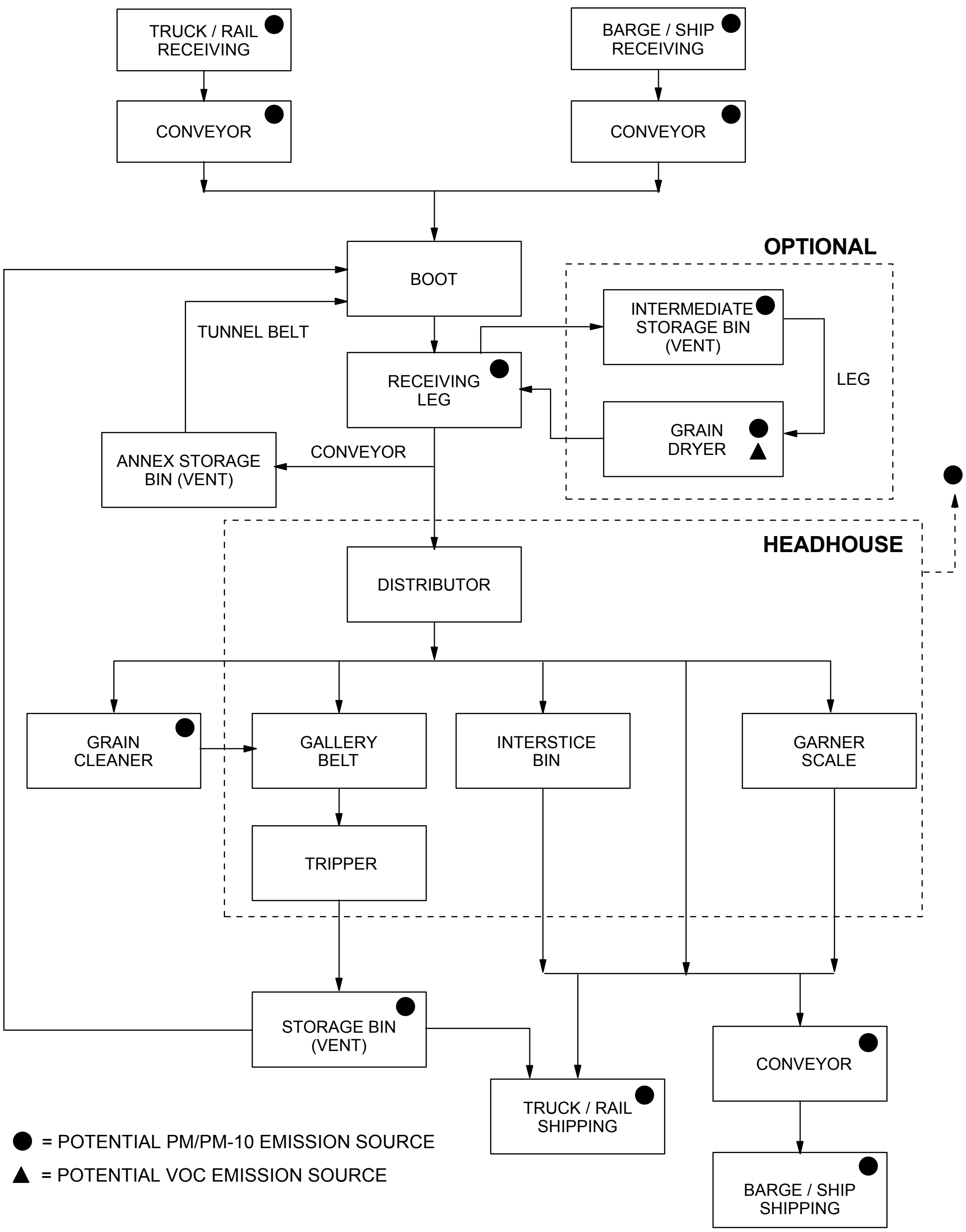

Figure 9.9.1-1. Major process operations at a grain elevator.

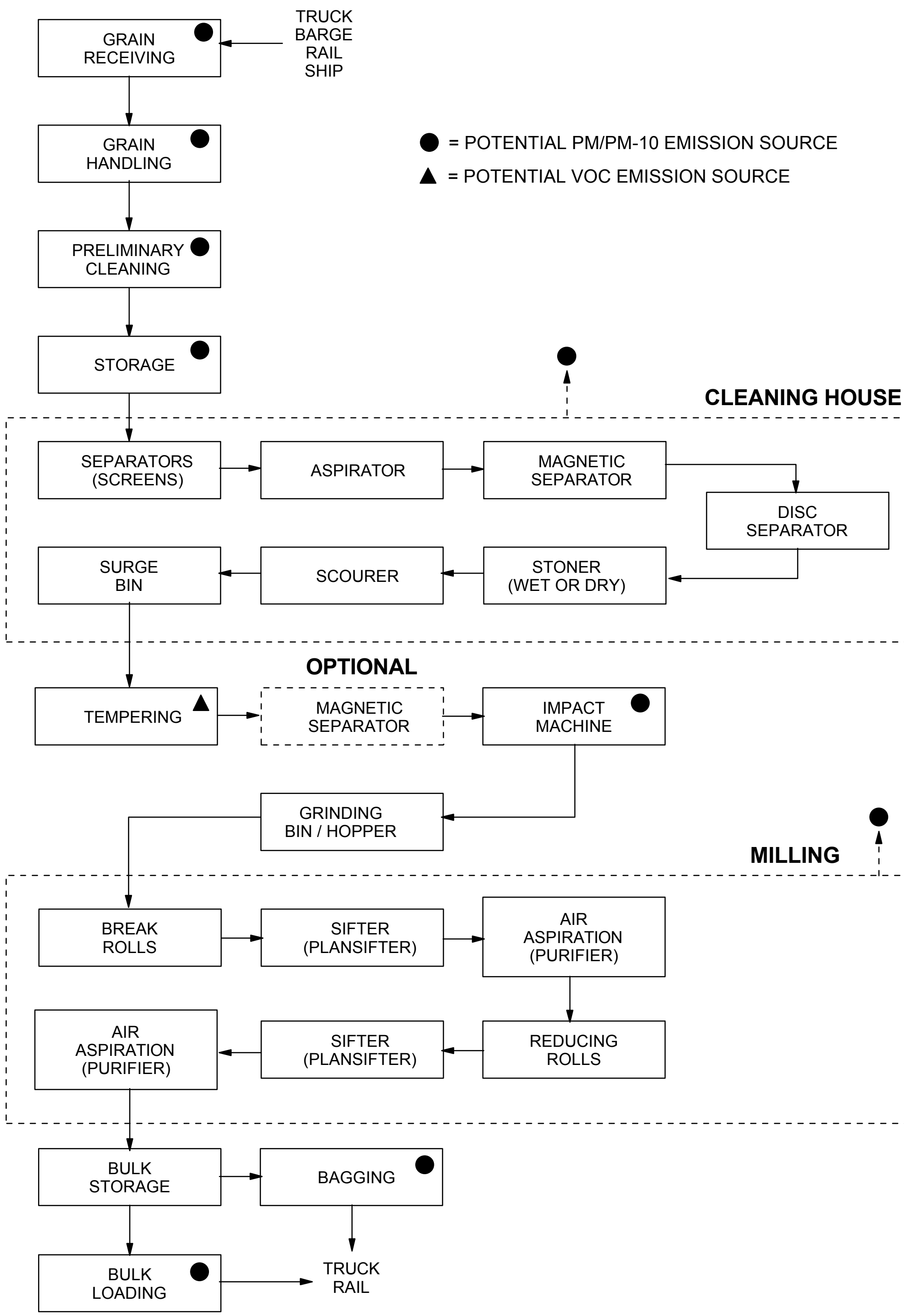

Figure 9.9.1-2. Simplified process flow diagram of a typical flour mill.

identical for durum and flour milling. The tempering step varies only slightly between the two processes. The tempering of durum uses the same equipment as wheat, but the holding times are shorter. Only the grain milling step differs significantly from the comparable flour milling step.

The break system in a durum mill generally has at least five sets of rolls for a gradual reduction of the stock to avoid producing large amounts of break flour. The rolls in the reduction system are used for sizing only, and not to produce flour. The sizing produces a uniform product for sale. The sifting system differs from that in a wheat flour mill in that it relies heavily on purifiers. In place of plansifters, conventional sieves are more common and are used to make rough separations ahead of the purifiers.

Rye milling and wheat flour milling are quite similar processes. The purpose of both processes is to make flour that is substantially free of bran and germ. The same basic machinery and process are employed. The flow through the cleaning and tempering portions of a rye mill is essentially the same as the flow through the wheat flour mill. However, because rye is more difficult to clean than wheat, this cleaning operation must be more carefully controlled.

In contrast to wheat milling, which is a process of gradual reduction with purification and classification, rye milling does not employ gradual reduction. Both the break and reduction roller mills in a rye mill are corrugated. Following grinding, the screening systems employ plansifters like those used in wheat flour mills. There is little evidence of purifier use in rye mills.

The wheat milling and rye milling processes are very similar because flour is the product of the break rolling system. In durum wheat flour milling, the intent is to produce as little flour as possible on the break rolls. As in wheat flour milling, the intent in rye milling is to make as much rye flour as possible on the break rolls. Consequently, there are more break rolls in proportion to reduction rolls in a rye mill than in a durum wheat flour mill.

9.9.1.1.2 Oat Milling[2,7] -

The milling process for oats consists of the following steps: (1) reception, preliminary cleaning, and storage; (2) cleaning; (3) drying and cooling; (4) grading and hulling; (5) cutting; (6) steaming; and (7) flaking. A simplified flow diagram of the oat milling process is shown in Figure 9.9.1-3. The receiving and storage operations are comparable to those described for grain elevators and for the wheat flour milling process. Preliminary cleaning removes coarse field trash, dust, loose chaff, and other light impurities before storage. After the oats are removed from storage, they flow to a milling separator combining coarse and fine screening with an efficient aspiration. In the next sequence of specialized cleaning operations, the oats are first routed to a disk separator for stick removal, and then are classified into three size categories. Each size category is subjected to a variety of processes (mechanical and gravitational separation, aspiration, and magnetic separation) to remove impurities. Large and short hulled oats are processed separately until the last stages of milling.

The next step in the oat processing system is drying and cooling. Oats are dried using pan dryers, radiator column dryers, or rotary steam tube dryers. Oats typically reach a temperature of 88° to 98°C (190° to 200°F) here, and the moisture content is reduced from 12 percent to 7 to 10 percent. After drying and cooling, the oats are ready for hulling; hulled oats are called groats. Some mills are now hulling oats with no drying or conditioning, then drying the groats separately to develop a toasted flavor. Hulling efficiency can be improved by prior grading or sizing of the oats. The free hulls are light enough that aspirators remove them quite effectively.

Generally, the final step in the large oat system is the separation of groats totally free of whole oats that have not had the hulls removed. These groats bypass the cutting operation and are directed to

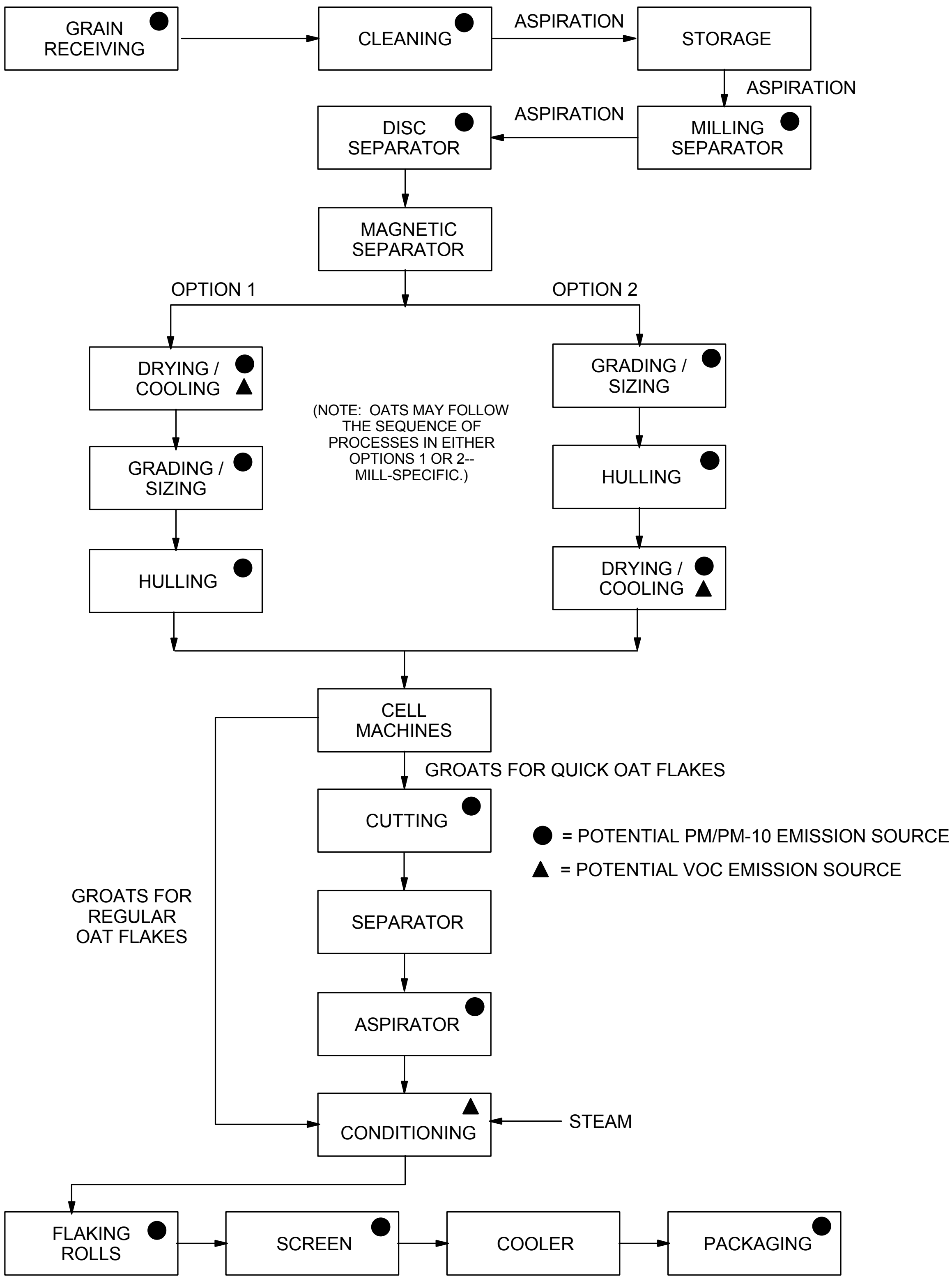

Figure 9.9.1-3. Flow diagram for oat processing operations.[8]

storage prior to flaking. The rejects are sent to the cutting plant. The cutting plant is designed to convert the groats into uniform pieces while producing a minimum of flour. The cut material is now ready for the flaking plant. First, the oats are conditioned by steaming to soften the groats thereby promoting flaking with a minimum of breakage. The steamed groats pass directly from the steamer into the flaking rolls. Shakers under the rolls remove fines and overcooked pieces are scalped off. The flakes generally pass through a dryer and cooler to quickly reduce moisture content and temperature which ensures acceptable shelf life. The cooled flakes are then conveyed to the packaging system.

9.9.1.1.3 Rice Milling[2,8-10]-

The first step in rice processing after harvest is drying using either fixed-bed or continuous-flow dryers to reduce the wet basis moisture content (MCwb) from 24 to 25 percent to 13 to 14 percent MCwb. Essentially all of the rice is dried either on the farm or at commercial drying facilities prior to shipping to the rice mill. After the rice is dried, it is stored and subsequently shipped to either conventional or parboil rice mills for further processing. There are three distinct stages in both mills: (1) rough rice receiving, cleaning, drying, and storage; (2) milling; and (3) milled rice and byproduct bagging, packaging, and shipping. A simplified flow diagram of the rice milling process is shown in Figure 9.9.1-4.

Grain is received primarily by truck and rail. The rough rice is precleaned using combinations of scalpers, screens, aspirators, and magnetic separators and then passed through a stoner, or gravity separator, to remove stones from the grain. The cleaned rice is transported to a disk huller where the rice is dehulled. The rice then passes through a sieve to remove bran and small brokens and to an aspirator to remove hulls. The unshelled rice grains (commonly called paddy) and brown rice are separated in a paddy separator. The unshelled paddy is then fed into another pair of shellers set closer together than the first set, and the process of shelling, aspiration, and separation is repeated.

From the paddy machines, the rice is conveyed to a sequence of milling machines called whitening cones, which scour off the outer bran coats and the germ from the rice kernels. Milling may be accomplished by a single pass through a mill or by consecutive passages through multiple whitening cones. The discharge from each stage is separated by a sieve. After the rice is milled, it passes through a polishing cone, which removes the inner bran layers and the proteinaceous aleurone layer. Because some of the kernels are broken during milling, a series of classifiers, known as trieurs, is used to separate the different size kernels. The rice may be sold at this point as polished, uncoated rice, or it may be conveyed to machines known as trumbels, in which the rice is coated with talc and glucose to give the surface a gloss. The rice is transferred to bulk storage prior to packing and shipping. For packing, the rice is transported to a packing machine where the product is weighed and placed in burlap sacks or other packaging containers.

In parboiling mills, the cleaned rough rice is steamed and dried prior to the milling operations. Pressure vessels are used for the steaming step, and steam tube dryers are used to dry the rice to 11 to 13 percent MCwb. Following the drying step, the rice is milled in conventional equipment to remove hull (bran), and germ.

9.9.1.1.4 Corn Dry Milling[2,12-13] -

Corn is dry milled by either a degerming or a nondegerming system. Because the degerming system is the principal system used in the United States, it will be the focus of the dry corn milling process description here. A simplified flow diagram of the corn dry milling process is shown in Figure 9.9.1-5. The degerming dry corn milling process is more accurately called the tempering degerminating (TD) system. The degerming system involves the following steps after receiving the grain: (1) dry cleaning, and if necessary, wet cleaning; (2) tempering; (3) separation of hull, germ, and

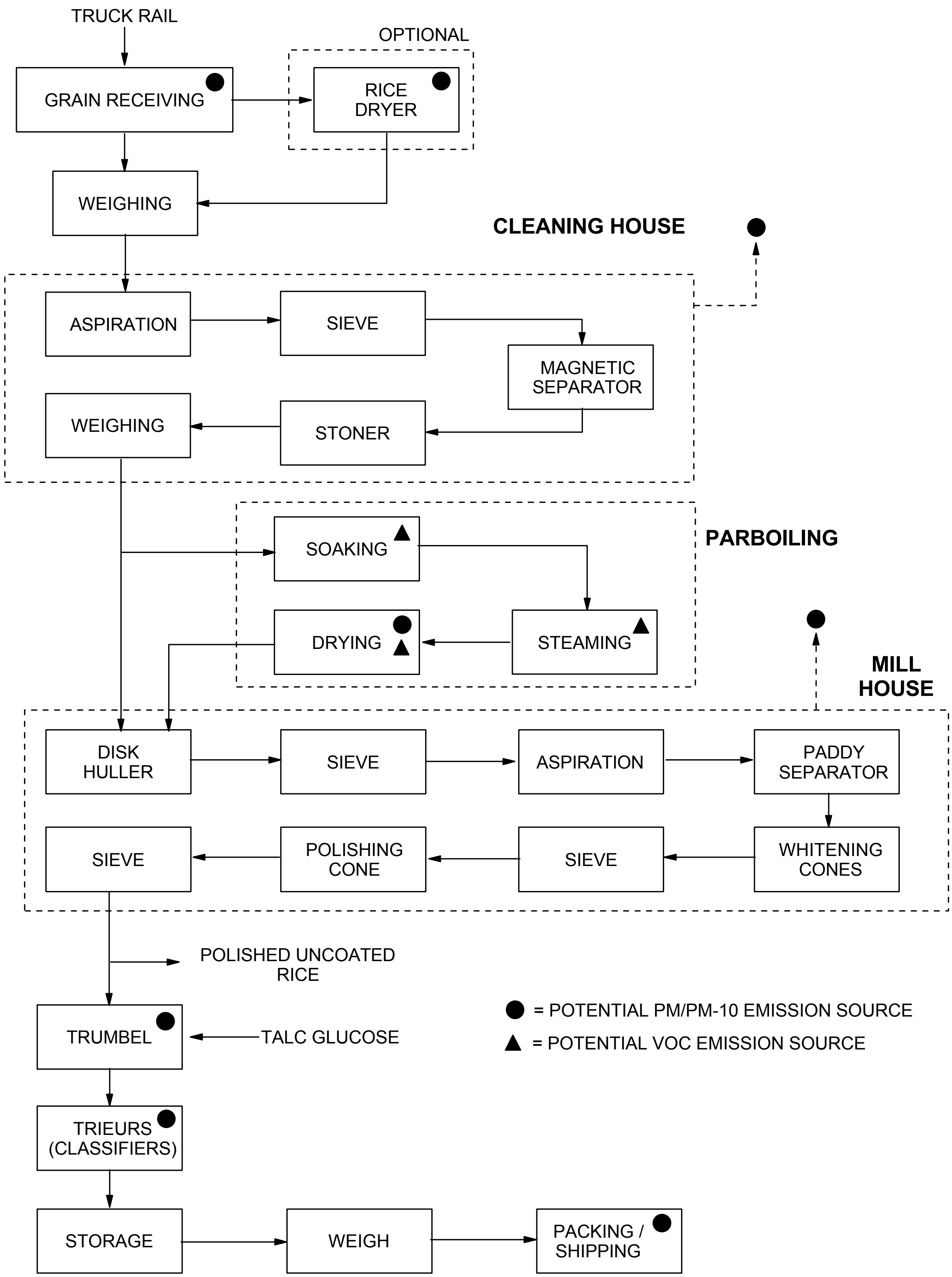

Figure 9.9.1-4. Flow diagram for conventional and parboil rice mills.

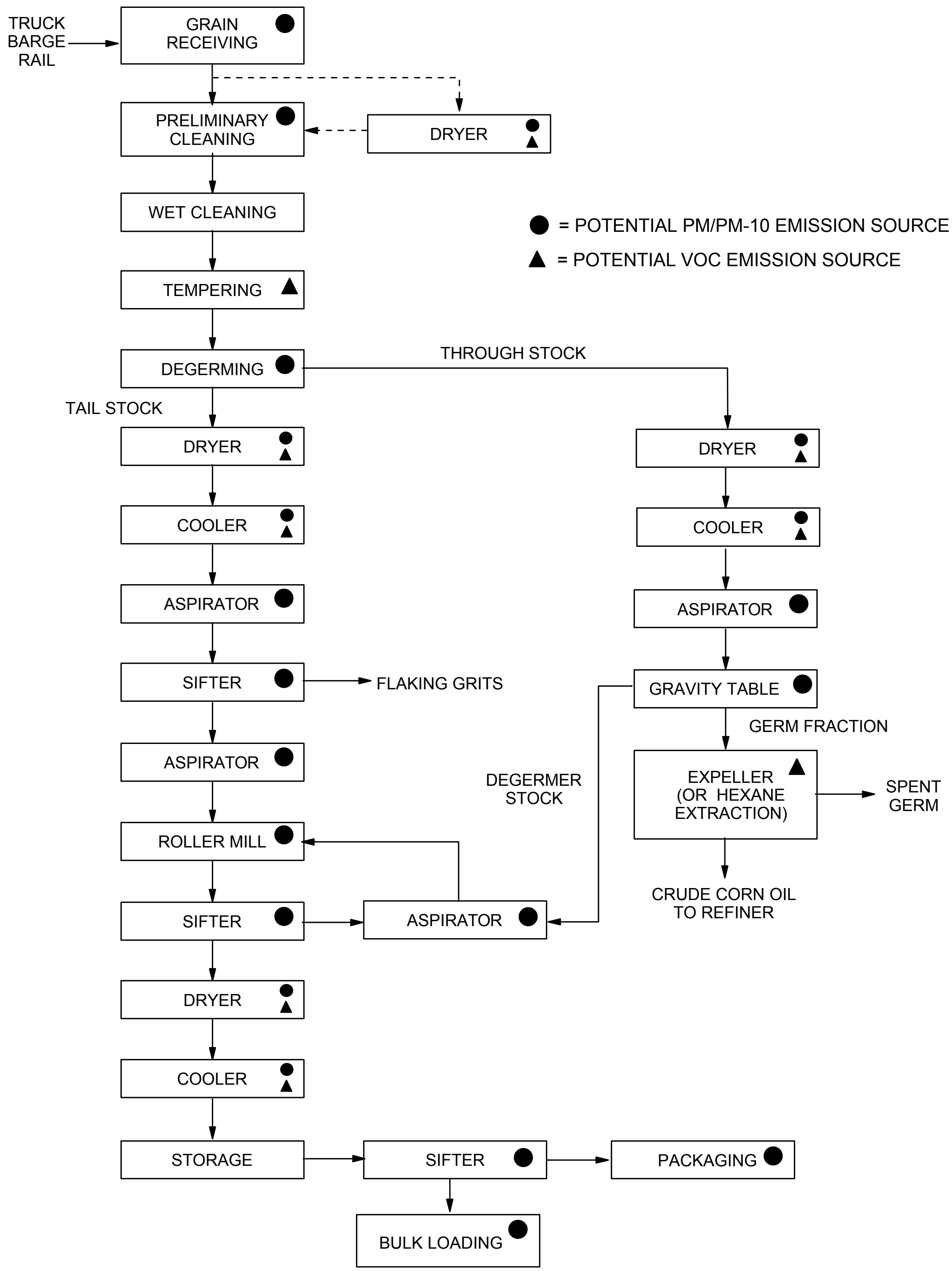

Figure 9.9.1-5. Simplified process flow diagram for a corn dry milling operation with degerming.

tip cap from the endosperm in the degerminator; (4) drying and cooling of degermer product; (5) multistep milling of degermer product through a series of roller mills, sifters, aspirators, and purifiers; (6) further drying of products, if necessary; (7) processing of germ fraction for recovery of crude corn oil; and (8) packaging and shipping of products.

Unloading and dry cleaning of corn is essentially the same as described for wheat. However, for corn, surface dirt and spores can best be removed by wet cleaning, which involves a washing-destoning unit followed by a mechanical dewatering unit. After cleaning, the corn is sent through the tempering or conditioning step, which raises the moisture content of the corn to 21 to 25 percent. After tempering, the corn is degermed, typically in a Beall degermer and corn huller. The Beall degermer is essentially an attrition device built in the form of a cone mill. The product exits in two streams, thru-stock and tail stock. Rotary steam-tube dryers are often used to dry the degermer product, because its moisture content must be in the 15 to 18 percent range for proper milling. After drying, the product is cooled to 32° to 37°C (90° to 100°F). After drying and cooling, the degermer stock is sifted or classified by particle size and is fed into the conventional milling system.

The milling section in a dry corn mill consists of sifting, classifying, milling, purifying, aspirating, and possibly, final drying operations. The feed to each pair of rolls consists of selected mill streams produced during the steps of sifting, aspirating, roller milling, and gravity table separating. For the production of specific products, various streams are withdrawn at appropriate points in the milling process. A number of process streams are often blended to produce a specific product. The finished products are stored temporarily in working bins, dried and cooled if necessary, and rebolted (sifted) before packaging or shipping in bulk.

Oil is recovered from the germ fraction either by mechanical screw presses or by a combination of screw presses and solvent extraction. A more detailed discussion of the corn oil extraction process is included in AP-42 Section 9.11.1, Vegetable Oil Processing.

9.9.1.1.5 Animal Feed Mills[2,5,14] -

The manufacture of feed begins with receiving of ingredients at the mill. A simplified flow diagram of the animal feed manufacturing process is shown in Figure 9.9.1-6. more than 200 ingredients may be used in feed manufacture, including grain, byproducts (e.g., meat meal, bone meal, beet and tomato pulp), and medicinals, vitamins, and minerals (used in very small portions). Grain is usually received at the mill by hopper bottom truck and/or rail cars, or in some cases, by barge. Most mills pass selected feed ingredients, primarily grains, through cleaning equipment prior to storage. Cleaning equipment includes scalpers to remove coarse materials before they reach the mixer. Separators, which perform a similar function, often consist of reciprocating sieves that separate grains of different sizes and textures. Magnets are installed ahead of the grinders and at other critical locations in the mill system to remove pieces of metal, bits of wire, and other foreign metallic matter, which could harm machinery and contaminate the finished feed. From the cleaning operation, the ingredients are directed to storage.

Upon removal from storage, the grain is transferred to the grinding area, where selected whole grains, primarily corn, are ground prior to mixing with other feed components. The hammermill is the most widely used grinding device. The pulverized material is forced out of the mill chamber when it is ground finely enough to pass through the perforations in the mill screen.

Mixing is the most important process in feed milling and is normally a batch process. Ingredients are weighed on bench or hopper scales before mixing. Mixers may be horizontal or vertical type, using either screws or paddles to move the ingredients. The material leaving the mixer is meal, or

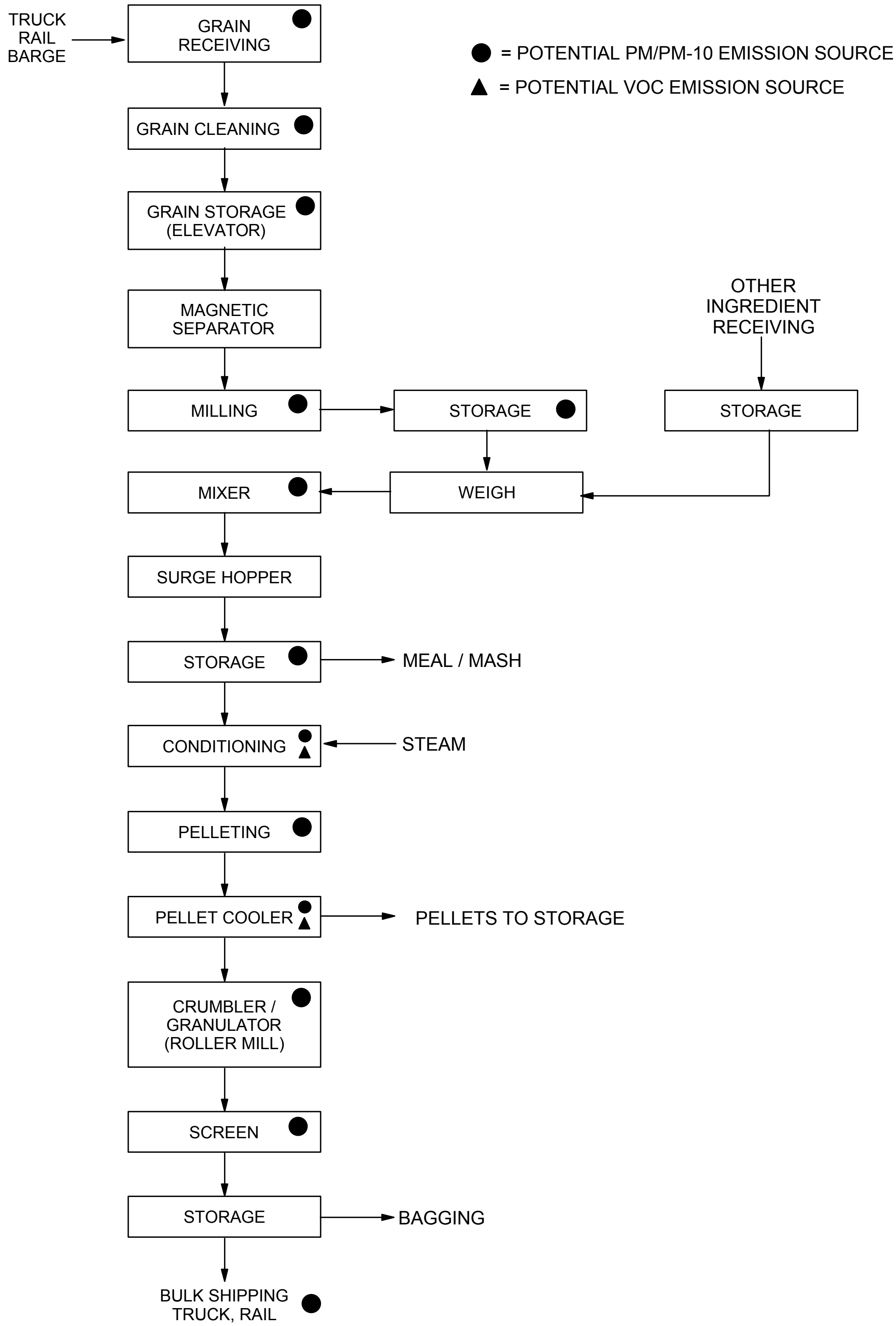

Figure 9.9.1-6. Typical animal feed milling process flow diagram.

mash, and may be marketed in this form. If pellets are to be made, the meal is conditioned with steam prior to being pelleted.

Pelleting is a process in which the conditioned meal is forced through dies. Pellets are usually 3.2 to 19 mm (1/8 to 3/4 in.) in diameter. After pelleting, pellets are dried and cooled in pellet coolers. If pellets are to be reduced in size, they are passed through a crumbler, or granulator. This machine is a roller mill with corrugated rolls. Crumbles must be screened to remove fines and oversized materials. The product is sent to storage bins and then bagged or shipped in bulk.

In modern feed mills, transport equipment is connected with closed spouting and turnheads, covered drag and screw conveyors, and tightly sealed transitions between adjoining equipment to reduce internal dust loss and consequent housekeeping costs. Also many older facilities have upgraded to these closed systems.

9.9.1.1.6 Malted Barley Production[36-37] -

Barley is shipped by railcar or truck to malting facilities. A screw conveyor or bucket elevator typically transports barley to storage silos or to the cleaning and sizing operations. The barley is cleaned and separated by size (using screens) and is then transferred to a malthouse where it is rinsed in steeping tanks (steeped) and is allowed to germinate. Following steeping and germination, “green” malt is dried, typically in an indirect-, natural gas-fired malt kiln. Malt kilns typically include multiple levels, called beds or layers. For a two-level kiln, green malt, with a moisture content of about 45 percent, enters the upper deck of the kiln and is dried, over a 24-hour period, to between 15 and 20 percent. The barley is then transferred to the lower deck of the kiln, where it is dried to about 4 percent over a second 24-hour period. Some facilities burn sulfur in a sulfur stove and exhaust the stove into the kiln at selected times during the kiln cycle. The sulfur dioxide serves as a fungicide, bactericide, and preservative. Malted barley is then transferred by screw conveyor to a storage elevator until it is shipped.

9.9.1.2 Emissions And Controls[2,5,14-39]

The main pollutant of concern in grain storage, handling, and processing facilities is particulate matter (PM). Organic emissions (e.g., hexane) from certain operations at corn oil extraction facilities may also be significant. These organic emissions (and related emissions from soybean and other oilseed processing) are discussed in AP-42 Section 9.11.1. Also, direct fired grain drying operations and product dryers in grain processing plants may emit small quantities of VOC’s and other combustion products; no data are currently available to quantify the emission of these pollutants. The following sections focus primarily on PM sources at grain elevators and grain milling/processing facilities.

9.9.1.2.1 Grain Elevators -

Except for barge and ship unloading and loading activities, the same basic operations take place at country elevators as at terminal elevators, only on a smaller scale and with a slower rate of grain movement. Emission factors for various grain elevator operations are presented later in this subsection. Because PM emissions at both types of elevators are similar, they will be discussed together in this subsection.

In trying to characterize emissions and evaluate control alternatives, potential PM emission sources can be classified into three groups. The first group includes external emission sources (grain receiving and grain shipping), which are characterized by direct release of PM from the operations to the atmosphere. These operations are typically conducted outside elevator enclosures or within partial enclosures, and emissions are quickly dispersed by wind currents around the elevator. The second group of sources are process emission sources that may or may not be vented to the atmosphere and include grain cleaning and headhouse and internal handling operations (e.g., garner and scale bins, elevator legs, and transfer points such as the distributor and gallery and tunnel belts). These operations are typically located inside the elevator structure. Dust may be released directly from these operations to the internal elevator environment, or aspiration systems may be used to collect dust generated from these operations to improve internal housekeeping. If aspiration systems are used, dust is typically collected in a cyclone or fabric filter before the air stream is discharged to the atmosphere. Dust emitted to the internal environment may settle on internal elevator surfaces, but some of the finer particles may be emitted to the environment through doors and windows. For operations not equipped with aspiration systems, the quantity of PM emitted to the atmosphere depends on the tightness of the enclosures around the operation and internal elevator housekeeping practices. The third group of sources includes those processes that emit PM to the atmosphere in a well-defined exhaust stream (grain drying and storage bin vents). Each of these operations is discussed in the paragraphs below.

The amount of dust emitted during the various grain-handling operations may depend upon the type of grain being handled, the quality or grade of the grain, the moisture content of the grain, the speed of the belt conveyors used to transport the grain, and the extent and efficiency of dust containment systems (i.e., hoods, sheds, etc.) in use at an elevator. Part of the dust liberated during the handling of grain at elevators gets into the grain during the harvesting operation. However, most of these factors have not been studied in sufficient detail to permit the delineation of their relative importance to dust generation rates.

Grain dust emitted from grain elevator handling operations comprises about 70 percent organic material. The dust may include particles of grain kernels, small amounts of spores of smuts and molds, insect debris, pollens, and field dust. Data recently collected on worker exposure to grain dust indicate that the characteristics of the dust released from processing operations to the internal elevator environment vary widely.[15] Because these dusts have a high organic content and a substantial suspendible fraction, concentrations above the minimum explosive concentration (MEC) pose an explosion hazard. Housekeeping practices instituted by the industry have reduced explosing hazards so this situation is rarely encountered in work areas.

Recent research on dust emissions from grain handling operations indicate that the fraction of dust particles equal to or less than 10 micrometers (µm) in aerodynamic diameter (PM-10) averages approximately 25 percent of total PM, and the fraction of dust particles less than 2.5 µm in aerodynamic diameter (PM-2.5) averages about 17 percent of PM-10.

Elevators in the United States receive grain by truck, railroad hopper car, and barge. The two principal factors that contribute to dust generation during bulk unloading are wind currents and dust generated when a falling stream of grain strikes the receiving pit. Falling or moving streams of grain initiate a column of air moving in the same direction. Grain unloading is an intermittent source of dust occurring only when a truck or car is unloaded. For country elevators it is a significant source during the harvest season and declines sharply or is nonexistent during other parts of the year. At terminal elevators, however, unloading is a year-round operation.

Trucks, except for the hopper (gondola) type, are generally unloaded by the use of some type of truck dumping platform. Hopper trucks discharge through the bottom of the trailer. Elevators are often designed with the truck unloading dump located in a drive-through tunnel. These drive-through areas are sometimes equipped with a roll-down door on one end, although, more commonly they are open at both ends so that the trucks can enter and leave as rapidly as possible. The drive-through access can act as a "wind-tunnel" in that the air may blow through the unloading area at speeds greater than the wind in the open areas away from the elevator. However, the orientation of the facility to the prevailing wind direction can moderate this effect. Many facilities have installed either roll-down or bi-fold doors to eliminate this effect. The use of these doors can greatly reduce the “wind tunnel” effect and enhance the ability to contain and capture the dust.

The unloading pit at a grain elevator usually consists of a heavy grate approximately 3.05 m x 3.05 m (10 ft x 10 ft) through which the grain passes as it falls into the receiving pit. This pit will often be partially filled with grain as the truck unloads because the conveyor beneath the pit does not carry off the grain as fast as it enters. The dust-laden air emitted by the truck unloading operation results from displacement of air out of the pit plus the aspiration of air caused by the falling stream of grain. The dust itself is composed of field dirt and grain particles. Unloading grain from hopper trucks with choke flow-practices can provide a substantial reduction in dust emissions.

Similarly, a hopper railcar can be unloaded with minimal dust generation if the material is allowed to form a cone around the receiving grate (i.e., choke feed to the receiving pit). This situation will occur when either the receiving pit or the conveying system serving the pit is undersized in comparison to the rate at which material can be unloaded from the hopper car. In such cases, dust is generated primarily during the initial stage of unloading, prior to establishment of the choked-feed conditions. Dust generated by wind currents can be minimized by the use of a shed enclosed on two sides with a manual or motorized door on one end or a shroud around the hopper discharge.

In most cases, barges are unloaded by means of a retractable bucket type elevator that is lowered into the hold of the barge. There is some generation of dust in the hold as the grain is removed and also at the top of the leg where the grain is discharged onto the transfer belt. This latter source is more appropriately designated a transfer point.

The loadout of grain from elevators into railcar, truck, barge, or ship is another important source of PM emissions and is difficult to control. Gravity is usually used to load grain from bins above the loading station or from the scale in the headhouse. The main causes of dust emissions when loading bulk grain by gravity into trucks or railcars is the wind blowing through the loading sheds and dust generated when the falling stream of grain strikes the truck or railcar hopper. The grain leaving the loading spout is often traveling at relatively high velocity, and dead boxes, aspiration, socks, or other means are often used to reduce dust emissions. Dust emitted during loading of barges and ships is comparable to levels generated during loading of trucks or railcars. The openings for the holds in ocean-going vessels may also be covered with tarps if needed to meet air quality standards.

Grain dryers present a difficult problem for air pollution control because of the large volumes of air exhausted from the dryer, the large cross-sectional area of the exhaust, the low specific gravity of the emitted dust, and the high moisture content of the exhaust stream. The rate of emission of PM from grain dryers is primarily dependent upon the type of grain, the dustiness of the grain, and the dryer configuration (rack or column type). The particles emitted from the dryers, although relatively large, may be very light and difficult to collect. However, during corn drying, the characteristic “bees wing” is emitted along with normal grain dust. “Bees wing,” a light flaky material that breaks off from the corn kernel during drying and handling, is a troublesome PM emission. Essentially, all bees wing emissions are more than 50 µm in diameter, and the mass mean diameter is probably in the region of 150 µm. In addition to the bees wings, the dust discharged from grain dryers consists of hulls, cracked grain, weed seeds, and field dust. Effluent from a corn dryer may consist of 25 percent bees wing, which has a specific gravity of about 0.70 to 1.2. Approximately 95 percent of the grain dust is larger than 50 µm.[2]

Cross-flow column dryers have a lower emission rate than rack dryers because some of the dust is trapped by the column of grain. In some cases, an enclosure may be built around the dryer that can act as a relatively effective settling chamber because of its moist environment. New grain dryers being sold today do not require the use of enclosures. In rack dryers drying corn, the emission rate for larger PM can be higher because the turning motion of the grain liberates more bees wings from the kernel, and the design facilitates dust escape. Some rack dryers are exhausted only from one or two points and are thus better suited for control device installation. The EPA's New Source Performance Standards (NSPS) for grain elevators established visible emission limits for grain dryers by requiring 0 percent opacity for emissions from column dryers and rack dryers. The NSPS zero opacity standard does not apply to column dryers with column plate perforations less than or equal to 2.4 mm in diameter (0.094 in.) or to rack dryers with a screen filter that has openings that are less than or equal to 50 mesh.

Equipment used to clean grain varies from simple screening devices to aspiration-type cleaners. Both types of systems potentially generate substantial quantities of PM depending on the design and extent of enclosure.

Both country and terminal elevators are usually equipped with garner and scale bins for weighing of grain. A country elevator may have only one garner bin and scale bin. However, a terminal elevator has multiple scale and garner bin systems, each with a capacity ranging from 42.3 to 88.1 m^3 (1,200 to 2,500 bu) to process 1,233 to 2,643 m^3/hr (35,000 to 75,000 bu/hr). Dust may be emitted from both the scale and garner bin whenever grain is admitted. The incoming stream of grain displaces air from the bin, and the displaced air entrains dust. The potential for emissions depends on the design of the system. For example, some facilities employ a relief duct that connects the two pieces of equipment to provide a path for displaced air. Also, in some cases, the bins are completely open at the top while some systems are completely enclosed.

The leg may be aspirated to remove dust created by the motion of the buckets and the grain flow. A variety of techniques are used to aspirate elevator legs. For example, some are aspirated at both the top and bottom; others are fitted with ducting from the top to the bottom in order to equalize the pressure, sometimes including a small blower to serve this purpose. The collected dust is discharged to a cyclone or filter. Leg vents may emit small amounts of dust under some operating conditions. However, these vents are often capped or sealed to prevent dust emissions. The sealing or capping of the vent is designed to act as an explosion relief vent after a certain internal pressure is reached to prevent damage to the equipment.

When grain is handled, the kernels scrape and strike against each other and the conveying medium. This action tends to rub off small particles of chaff and to fragment some kernels. Dust is continuously generated, and the grain is never absolutely clean. Belt conveyors have less rubbing friction than either screw or drag conveyors, and therefore, generate less dust. Dust emissions usually occur at belt transfer points as materials fall onto or away from a belt. Belt speed has a strong effect on dust generation at transfer points. Examples of transfer points are the discharge from one belt conveyor or the discharge from a bin onto a tunnel belt.

Storage bin vents, which are small screen-covered openings located at the top of the storage bins, are used to vent air from the bins as the grain enters. The grain flow into a bin induces a flow of air with the grain, and the grain also displaces air out of the bin. The air pressure that would be created by these mechanisms is relieved through the vents. The flow of grain into the bin generates dust that may be carried out with the flow of air through the bin vents. The quantity of dust released through the vents increases as the level of the grain in the bin increases. Bin vents are common to both country and terminal elevators, although the quantity of dust emitted is a function of the grain handling rate, which is considerably higher in terminal elevators.

The three general types of measures that are available to reduce emissions from grain handling and processing operations are process modifications designed to prevent or inhibit emissions, capture/ collection systems, and oil suppression systems that inhibit release of dust from the grain streams. The following paragraphs describe the general approaches to process controls, capture systems, and oil suppression. The characteristics of the collection systems most frequently applied to grain handling and processing plants (cyclones and fabric filters) are then described, and common operation and maintenance problems found in the industry are discussed.

Because emissions from grain handling operations are generated as a consequence of mechanical energy imparted to the dust by the operations themselves and local air currents in the vicinity of the operations, an obvious control strategy is to modify the process or facility to limit the effects of those factors that generate emissions. The primary preventive measures that facilities have used are construction and sealing practices that limit the effect of air currents and minimizing grain free fall distances and grain velocities during handling and transfer. Some construction and sealing practices that minimize emissions are enclosing the receiving area to the degree practicable, preferably with doors at both ends of a receiving shed; specifying dust-tight cleaning and processing equipment; using lip-type shaft seals at bearings on conveyor and other equipment housings; using flanged inlets and outlets on all spouting, transitions, and miscellaneous hoppers; and fully enclosing and sealing all areas in contact with products handled.

A substantial reduction in emissions from receiving, shipping, handling, and transfer areas can be achieved by reducing grain free fall distances and grain velocities. Choke unloading reduces free fall distance during hopper car unloading. The same principle can be used to control emissions from grain transfer onto conveyor belts and from loadout operations. An example of a mechanism that is used to reduce grain velocities is a “dead box” spout, which is used in grain loadout (shipping) operations. The dead box spout slows down the flow of grain and stops the grain in an enclosed area. The dead box is mounted on a telescoping spout to keep it close to the grain pile during operation. In principle, the grain free falls down the spout to an enclosed impact dead box, with grain velocity going to zero. It then falls onto the grain pile. Typically, the entrained air and dust liberated at the dead box is aspirated back up the spout to a dust collector. Finally, several different types of devices are available that, when added to the end of the spout, slow the grain flow and compress the grain discharge stream. These systems entrap the dust in the grain stream, thereby providing a theoretical reduction in PM emissions. There are few, if any, test data from actual ship or barge loading operations to substantiate this theoretical reduction in emissions.

While the preventive measures described above can minimize emissions, most facilities also require ventilation, or capture/collection, systems to reduce emissions to acceptable levels. In fact, air aspiration (ventilation) is a part of the dead box system described above. Almost all grain handling and processing facilities, except relatively small grain elevators, use capture/collection on the receiving pits, cleaning operations, and elevator legs. Generally, milling and pelletizing operations at processing plants are ventilated, and some facilities use hooding systems on all handling and transfer operations.

Grain elevators that rely primarily on aspiration typically duct many of the individual dust sources to a common dust collector system, particularly for dust sources in the headhouse. Thus, aspiration systems serving elevator legs, transfer points, bin vents, etc., may all be ducted to one collector in one elevator and to two or more individual systems in another. Because of the myriad possibilities for ducting, it is nearly impossible to characterize a “typical” grain elevator from the standpoint of delineating the exact number and types of air pollution sources and the control configurations for those sources.

The control devices typically used in the grain handling and processing industry are cyclones (or mechanical collectors) and fabric filters. Cyclones are generally used only on country elevators and small processing plants located in sparsely populated areas. Terminal elevators and processing plants located in densely populated areas, as well as some country elevators and small processing plants, normally use fabric filters for control. Both of these systems can achieve acceptable levels of control for many grain handling and processing sources. Although cyclone collectors can achieve acceptable performance in some scenarios, and fabric filters are highly efficient, both devices are subject to failure if they are not properly operated and maintained. Also, malfunction of the ventilation system can lead to increased emissions at the source.

The emission control methods described above rely on either process modifications to reduce dust generation or capture collection systems to control dust emissions after they are generated. An alternative control measure that has developed over the last 10 years is dust suppression by oil application. The driving forces for developing most such dust suppression systems have been grain elevator explosion control as well as emission control. Consequently, few data have been published on the amount of emission reduction achieved by such systems. Recent studies, however, have indicated that a PM reduction of approximately 60 to 80 percent may be achievable (see References 57 and 61 in Section 4 of the Background Report).

Generally, these oil application dust suppression systems use either white mineral oil, soybean oil, or some other vegetable oil. Currently the Food and Drug Administration restricts application rates of mineral oil to 0.02 percent by weight. Laboratory testing and industry experience have shown that oil additives applied at a rate of 60 to 200 parts per million by weight of grain, or 0.5 to 1.7 gallons of oil per thousand bushels of grain can provide effective dust control.[39] The effectiveness of the oil suppression system depends to some extent on how well the oil is dispersed within the grain stream after it is applied. Several options are available for applying oil additives.

1. As a top dressing before grain enters the bucket elevator or at other grain transfer points.
2. From below the grain stream at a grain transfer point using one or more spray nozzles.
3. In the boot of the bucket elevator leg.
4. At the discharge point from a receiving pit onto a belt or other type conveyor.
5. In a screw conveyor.

9.9.1.2.2 Grain Processing Plants -

Several grain milling operations, such as receiving, conveying, cleaning, and drying, are similar to those at grain elevators. In addition, applications of various types of grinding operations to the grain, grain products, or byproducts are further sources of emissions. The hammermill is the most widely used grinding device at feed mills. Some product is recovered from the hammermill with a cyclone collector or baghouse. Mills, similar to elevators, use a combination of cyclones and fabric filters to conserve product and to control emissions. Several types of dryers are used in mills, including the traditional rack or column dryers, fluidized bed dryers (soybean processing), and flash-fired or direct-fired dryers (corn milling). These newer dryer types might have lower emissions, but data are insufficient at this time to quantify the difference. The grain precleaning often performed before drying also likely serves to reduce emissions.

Because of the operational similarities, emission control methods used in grain milling and processing plants are similar to those in grain elevators. Cyclones or fabric filters are often used to control emissions from the grain handling operations (e. g., unloading, legs, cleaners, etc.) and also from other processing operations. Fabric filters are used extensively in flour mills. However, certain operations within milling operations are not amenable to the use of these devices and alternatives are needed. Wet scrubbers, for example, are applied where the effluent gas stream has a high moisture content. A few operations have been found to be difficult to control by any method. Various emission control systems have been applied to operations within the grain milling and processing industry.[2]

Grain processing facilities also have the potential to emit gaseous pollutants. Natural gas-fired dryers and boilers are potential sources of combustion byproducts and VOC. The production of various modified starches has the potential for emissions of hydrochloric acid or ethylene oxide. However, no data are available to confirm or quantify the presence of these potential emissions. Neither are there any data available concerning the control of these potential emissions.

Table 9.9.1-1 presents emission factors for filterable PM and PM-10 emissions from grain elevators. Table 9.9.1-2 presents emission factors for filterable PM; PM-10; inorganic, organic and total condensible PM emissions from grain processing facilities.

The most recent source test data for grain elevators either does not differentiate between country and inland terminal elevators or does not show any significant difference in emission factors between these two types of elevators. There are no current emission source test data for export terminal elevators. Because there is no significant difference in emission factors between different types of elevators, the emission factors presented in Table 9.9.1-1 are for grain elevators, without any distinction between elevator types.

In Tables 9.9.1-1 and 9.9.1-2, a number of potential emission sources are presented for each type of facility. The number and type of processes that occur within a specific elevator or grain processing plant will vary considerably from one facility to another. The total emissions from a specific facility will be dependent upon the different types of processes and the number of times a process or operation occurs within each facility. Not all processes occur at every facility; therefore, the specific emission sources and number of sources must be determined for each individual facility. It is not appropriate to sum emission factors for all sources and assume that total factor for all facilities.

9.9.1.3 Example Use of Emission Factor Table

The emission factors in Table 9.9.1-1 predict emissions from different operations at grain handling facilities. Except where specifically noted in the tables, the factors predict uncontrolled emissions.

The following guidance (with illustrative examples) is provided to users to promote greater consistency in the application of the data in Table 9.9.1-1.

(1) The emission factors for grain receiving and grain shipping (e.g., rail, truck, barge and/or ship) should be applied to the total amount of grain received and/or shipped by that mode of transportation.

Example: Facility reports shipping 1 million tons of grain by vessel. The calculated uncontrolled PM-10 emissions are:

1,000,000 tons x 0.012 lbs/ton = 12,000 lbs or 6 tons of PM-10

Example: Facility reports receiving 2 million tons of grain using a continuous barge unloader (e.g., Heyl-Patterson or Link Belt). The calculated uncontrolled PM-10 emissions are:

2,000,000 tons x 0.0073 lbs/ton = 14,600 lbs or 7.3 tons of PM-10

(2) Truck receiving can represent a unique situation at grain handling facilities. The preponderance of grain facilities receive grain by both straight and hopper bottom trucks. When actual truck counts/receipts by type of truck are not known, the emission factor for trucks should represent a weighted-average or a conservative percentage of the distribution of straight and hopper bottom trucks normally handled at the facility, or at a similar facility. The use of hopper bottom trucks to haul grain is steadily increasing over time. In some cases, industry reports that receipts of grain by hopper bottom trucks can often exceed 75 percent and in some cases represent nearly 100 percent of truck receipts. Thus, exclusive reliance on the emission factor for straight trucks would normally result in emission estimates that are strongly biased high.

Example: Facility reports receiving 42,000 tons of grain by truck with 75% being hopper bottom trucks and 25% straight trucks. The weighted average PM-10 emission factor for this facility is:

0.75 x 0.0078 lbs/ton = 0.006 lbs/ton
0.25 x 0.059 lbs/ton = <u>0.015 lbs/ton</u>
Weighted average = 0.021 lbs/ton

Using this factor, the calculated uncontrolled PM-10 emissions from the truck dump can be calculated:

0.021 lbs/ton x 42,000 tons = 882 lbs or 0.44 tons of PM-10

Where actual truck counts/recipts by type of truck are known, then the above calculations can be made directly.

(3) The emission factors for headhouse and internal handling, and bin vents should be applied to the total amount of grain that is handled by these facilities. The headhouse and internal handling emission factor represents dust emissions from bin and basement conveyors, internal cleaners not vented to the atmosphere, scales, garners, legs and distributors.

Example: The facility reports that it handles 50,000 tons of grain. The calculated uncontrolled PM-10 emissions from these operations are:

50,000 tons x 0.034 lbs/ton = 1,700 lbs or 0.85 tons of PM-10

(4) The emission factor for internal vibrating cleaners is based on emissions from a control device and should be applied only in cases when the emissions are vented to the atmosphere. In cases where the internal cleaner is controlled with a fabric filter, calculated emissions will be biased high and the difference between the control efficiencies of both types of control devices should be accounted for when arriving at the final estimate. In cases where emissions from an internal cleaner are not controlled with a fabric filter or cyclone control device, the headhouse and internal operations emission factor accounts for any internal emissions from equipment within the structure that might escape to the atmosphere.

Example: The facility reports that it cleaned 5,000 tons of grain. The cleaner is aspirated using a cyclone collector and the emissions are vented to the atmosphere. The calculated controlled PM-10 emissions are:

5,000 tons x 0.019 lbs/ton = 94 lbs or .05 tons of PM-10

(5) The emission factors for column and rack dryers should be applied to the amount of grain dried by the facility. As rack dryers are normally equipped with self-cleaning rotary screens, it would be appropriate to apply the controlled emission factor for the rack dryer to the total amount of grain dried at the facility.

Example: The facility reports drying 10,000 tons of grain using a column dryer. The calculated uncontrolled PM-10 emissions are:

10,000 tons x 0.055 lbs/ton = 550 lbs or 0.28 tons of PM-10

Example: The facility reports drying 10,000 tons of grain using a rack dryer that is equipped with a self-cleaning rotary screen. The calculated controlled PM-10 emissions are:

10,000 x 0.12 lbs/ton = 1,200 lbs or 0.60 tons of PM-10

Example of the application of the emission factors in Table 9.9.1-1 to different types of grain handling operations:

Example 1 (uncontrolled emissions): A country elevator that receives 50,000 tons of grain by truck (80% by hopper and 20% by straight truck) and ships 8,000 tons by truck and 40,000 tons by rail (2,000 tons remain in storage). The facility also dried 10,000 tons of grain using a column dryer and cleaned 40,000 tons with an internal vibrating cleaner controlled by a cyclone cleaner vented to the atmosphere. The 48,000 tons shipped had to be re-elevated for loadout. The grain cleaned also was re-elevated as the grain was dried. Therefore, the grain handled is the grain received, plus that shipped, plus that cleaned, plus that dried. Calculated uncontrolled PM-10 emissions from the facility would be:

<u>Receiving</u>:

(0.8 x 0.0078 + 0.2 x 0.059) x 50,000 tons = 900 lbs or 0.45 tons of PM-10

<u>Shipping</u>:

0.029 x 8,000 tons + 0.0022 x 40,000 tons = 320 lbs or 0.16 tons of PM-10

<u>Handling/Internal Operations</u>:

0.034 x (50,000 + 48,000 + 40,000 + 10,000) tons = 5,000 lbs or 2.5 tons of PM-10

<u>Cleaning</u>:

0.019 x 40,000 tons = 760 lbs or 0.38 tons of PM-10

<u>Drying</u>:

0.055 x 10,000 tons = 550 lbs or 0.28 tons of PM-10

Total uncontrolled emissions of PM-10 from the facility would then be the sum of the above emissions or 7,500 lbs or 3.8 tons. To estimate total particulate (PM) emissions, multiply the PM-10 emissions for the facility by 4 so that, for this example, PM emissions would equal approximately 30,000 lbs or 15.2 tons.

Example 2 (controlled emissions): A system (conveying, cleaning, receiving, etc.) is aspirated to a baghouse filter. The facility reports handling 50,000 tons and that the design capacity of the aspiration system is 18,000 cubic feet per minute (cfm). A Method 5 emission test on a comparable system revealed a filter exhaust loading of 0.005 grains per actual cubic foot (gr/acf) of exhaust air and the typical handling rate of the system in question is 350 tons/hour.

The controlled emissions from the system would be calculated as follows:

0.005 gr/acf x 1 lb/7,000 grains x 18,000 acf/min x 60 min/hr x (50,000 tons/year)/(350 tons/hour)
= 110 lbs or 0.055 tons of PM.

9.9.1.4 Updates Since the Fifth Edition

The background document (Reference 1) for this section was released in May 1998 with the AP-42 section appearing as part of Supplement D in June 1998. Revisions to Section 9.9.1 since that date are summarized below:

April 2003 -- Emission factors for barge and ship loading/unloading incorporated into Table 9.9.1. Table 9.9.1 expanded to include PM-2.5 emission factors and ratings. Particle size data from Reference 40 used to scale PM-10 emission factors to other particle size ranges. Changes documented in Reference 41. Bin vent emission factor restored from earlier version of Table 9.9.1-1. Additional text revisions for clarification and to reflect current practice in the industry.

Table 9.9.1-1. PARTICULATE EMISSION FACTORS FOR GRAIN ELEVATORS[a]

Emission Source	Type of Control	Filterable[b]					
		PM	EMISSION FACTOR RATING	PM-10[c]	EMISSION FACTOR RATING	PM-2.5[d]	EMISSION FACTOR RATING
Grain receiving (SCC 3-02-005-05)							
Straight truck (SCC 3-02-005-51)	None	0.18[e]	E	0.059[f]	E	0.010[g]	E
Hopper truck (SCC 3-02-005-52)	None	0.035[e]	E	0.0078[f]	E	0.0013[g]	E
Railcar (SCC 3-02-005-53)	None	0.032[f]	E	0.0078[f]	E	0.0013[g]	E
Barge (SCC 3-02-005-54)							
Continuous barge unloader (SCC 3-02-005-56)	None	0.029[h]	E	0.0073[j]	E	0.0019[j]	E
Marine leg (SCC 3-02-005-57)	None	0.15[h]	E	0.038[j]	E	0.0050[j]	E
Ships (SCC 3-02-005-55)	None	0.15[k]	E	0.038[k]	E	0.0050[k]	E
Grain cleaning (SCC 3-02-005-03)							
Internal vibrating (SCC 3-02-005-37)	Cyclone	0.075[m]	E	0.019[n]	E	0.0032[g]	E
Grain drying (SCC 3-02-005-04)							
Column dryer (SCC 3-02-005-27)	None	0.22[p]	E	0.055[n]	E	0.0094[g]	E
Rack dryer (SCC 3-02-005-28)	None	3.0[p]	E	0.75[n]	E	0.13[g]	E
	Self-cleaning screens (<50 mesh)	0.47[p]	E	0.12[n]	E	0.020[g]	E
Headhouse and grain handling (SCC 3-02-005-30) (legs, conveyors, belts, distributor, scale, enclosed cleaners, etc.)	None	0.061[f]	E	0.034[f]	E	0.0058[g]	E
Storage bin (vent) (SCC 3-02-005-40)	None	0.025[q]	E	0.0063[n,q]	E	0.0011[g,q]	E

Table 9.9.1-1 (cont.).

Emission Source	Type of Control	Filterable[b]					
		PM	EMISSION FACTOR RATING	PM-10[c]	EMISSION FACTOR RATING	PM-2.5[d]	EMISSION FACTOR RATING
Grain shipping (SCC 3-02-005-06)							
Truck (unspecified) (SCC 3-02-005-60)	None	0.086[e]	E	0.029[f]	E	0.0049[g]	E
Railcar (SCC 3-02-005-63)	None	0.027[f]	E	0.0022[f]	E	0.00037[g]	E
Barge (SCC 3-02-005-64)	None	0.016[h]	E	0.0040[j]	E	0.00055[j]	E
Ship (SCC 3-02-005-65*)	None	0.048[h]	E	0.012[j]	E	0.0022[j]	E

[a] Specific sources of emission factors are cited in Reference 1, Table 4-16 and supporting tables, except as indicated in the following footnotes. Factors are in units of lb/ton of grain handled or processed. Lb/ton divided by 2 gives kg/Mg. SCC = Source Classification Code. ND = no data available. Example uses of emission factors in this table are provided in Section 9.9.1.3.
[b] Weight of total filterable PM, regardless of size, per unit weight of grain throughput.
[c] Weight of PM $\leq$ 10 micrometers (µm) in aerodynamic diameter per unit weight of grain throughput.
[d] Weight of PM $\leq$ 2.5µm in aerodynamic diameter per unit weight of grain throughput.
[e] Mean of two values from References 18 and 19.
[f] Reference 19.
[g] Emission factor for PM-10 scaled to PM-2.5 using the mean ratio of 17 percent from Reference 40.
[h] PM-10 emission factor scaled to total particulate using the ratio of 25 percent presented in Reference 1.
[j] Reference 40.
[k] Unloading a vessel with a marine leg is analogous to use of a marine leg in barge unloading.
[m] Mean of six A- and C-rated data points from References 20, 21, 22, 23, and 24.
[n] PM-10 emission factor estimated by taking 25 percent of the filterable PM emission factor.
[p] Mean of two D-rated data points from Reference 2.
[q] Based on average of wheat and sorghum PM emission factors reported in Reference 42. PM emission factors based on data at the inlet of an aspirated capture/collection system. Due to natural removal processes, uncontrolled emissions may be overestimated compared to those emissions that occur without such a system.

* SCC was corrected by D. Safriet 3/3/2004

Table 9.9.1-2. PARTICULATE EMISSION FACTORS FOR GRAIN PROCESSING FACILITIES[a]

Type of Facility/ Emission Source	Type of Control	Filterable[b]				Condensible PM[c]			
		PM	EMISSION FACTOR RATING	PM-10[d]	EMISSION FACTOR RATING	Inorganic	Organic	Total	EMISSION FACTOR RATING
Animal feed mills									
Grain receiving (SCC 3-02-008-02)	None	0.017[e]	E	0.0025[e]	E				
Grain cleaning (SCC 3-02-008-07)	Cyclone	(f)		(f)					
Storage	None	ND		ND					
Grain milling (SCC 3-02-008-15)									
Hammermill (SCC 3-02-008-17)	Cyclone	0.067[h]	E	(g)					
	Baghouse	0.012[j]	E	(y)					
Flaker (SCC 3-02-008-18)	Cyclone	0.15[k]	E	(g)					
Grain cracker (SCC 3-02-008-19)	Cyclone	0.024[k]	E	(g)					
Mixer	None	ND		ND					
Conditioning	None	ND		ND					
Pelletizing Pellet cooler[m] (SCC 3-02-008-16)	Cyclone	0.36[n]	E	(g)		--	--	0.059[p]	E
	High efficiency cyclone[r]	0.15[q]	E	(g)					
Feed shipping (SCC 3-02-008-03)	None	0.0033[e]	E	0.0008[e]	E				
Wheat flour mills									
Grain receiving (SCC 3-02-007-31)	None	(f)		(f)					
Grain handling (SCC 3-02-007-32) (legs, belts, etc.)	None	(f)		(f)					

Table 9.9.1-2 (cont.).

Type of Facility/ Emission Source	Type of Control	Filterable[b]				Condensible PM[c]			
		PM	EMISSION FACTOR RATING	PM-10[d]	EMISSION FACTOR RATING	Inorganic	Organic	Total	EMISSION FACTOR RATING
Cleaning house separators (SCC 3-02-007-33)	Cyclone	0.012[s]	E	(g)					
Wheat milling (SCC 3-02-007-34) (roller mill)	None	70[s]	E	(g)					
Bulk loading		ND		ND					
Corn dry mills									
Grain receiving (SCC 3-02-007-41)	None	(f)		(f)					
Grain drying (SCC 3-02-007-42)	None	(f)		(f)					
Grain handling (SCC 3-02-007-43) (legs, belts, etc.)	None	(f)		(f)					
Grain cleaning (SCC 3-02-007-44)	None	(f)		(f)					
Degermer/milling (SCC 3-02-007-45)		ND		ND					
Bulk loading		ND		ND					
Rice Mills									
Grain receiving (SCC 3-02-007-71)	None	ND		ND					
Precleaning/handling (SCC 3-02-007-72)		ND		ND					
Rice drying (SCC 3-02-007-73)	None	0.063[t]	E	(g)					
Cleaning house (SCC 3-02-007-74)		ND		ND					

Table 9.9.1-2 (cont.).

Type of Facility/ Emission Source	Type of Control	Filterable[b]				Condensible PM[c]			
		PM	EMISSION FACTOR RATING	PM-10[d]	EMISSION FACTOR RATING	Inorganic	Organic	Total	EMISSION FACTOR RATING
Parboiling	None	ND		ND					
Mill house (SCC 3-02-007-76)	Fabric filter	0.27[u]	E	(y)					
Paddy cleaner (SCC 3-02-007-75)	Fabric filter	0.0031[u]	E	(y)					
Aspirator (SCC 3-02-007-77)	Fabric filter	0.0030[u]	E	(y)					
Bran handling (SCC 3-02-007-78)	Fabric filter	0.017[u]	E	(y)					
Trumbel	None	ND		ND					
Trieurs	None	ND		ND					
Packaging/Shipping		ND		ND					
<u>Durum Mills</u>									
Grain receiving (SCC 3-02-007-11)		(f)		(f)					
Grain precleaning/ handling (SCC 3-02-007-12)		ND		ND					
Cleaning house (SCC 3-02-007-13)		ND		ND					
Durum milling (SCC 3-02-007-14)		ND		ND					
Bulk loading		ND		ND					

Table 9.9.1-2 (cont.).

Type of Facility/ Emission Source	Type of Control	Filterable[b]				Condensible PM[c]			
		PM	EMISSION FACTOR RATING	PM-10[d]	EMISSION FACTOR RATING	Inorganic	Organic	Total	EMISSION FACTOR RATING
Rye Mills									
Grain receiving (SCC 3-02-007-21)		(f)		(f)					
Grain precleaning/ handling (SCC 3-02-007-22)		(f)		(f)					
Cleaning house (SCC 3-02-007-23)		ND		ND					
Rye milling (SCC 3-02-007-24)		ND		ND					
Bulk loading		ND		ND					
Oat Mills (SCC 3-02-007-60)									
Grain receiving		(f)		(f)					
Grain cleaning		(f)		(f)					
Separators		ND		ND					
Drying/cooling		ND		ND					
Grading/sizing		ND		ND					
Hulling		ND		ND					
Cutting		ND		ND					
Steaming/conditioning		ND		ND					
Flaking		ND		ND					
Screening		ND		ND					
Packaging		ND		ND					

Table 9.9.1-2 (cont.).

Type of Facility/ Emission Source	Type of Control	Filterable[b]				Condensible PM[c]			
		PM	EMISSION FACTOR RATING	PM-10[d]	EMISSION FACTOR RATING	Inorganic	Organic	Total	EMISSION FACTOR RATING
<u>Barley Malting</u>									
Grain receiving (SCC 3-02-007-08)	Fabric filter	0.016[v]	E	(y)					
Gas-fired malt kiln (SCC 3-02-007-09)	None	0.19[w]	E	0.17[x] (PM-2.5 =0.075)	E	0.075[x]	0.013[x]	0.088[x]	E

[a] Specific sources of emission factors are cited in Reference 1, Table 4-17 and supporting tables. Factors are in unit of lb/ton of grain handled or processed. Lb/ton divided by 2 gives kg/Mg. SCC = Source Classification Code. ND = no data available.
[b] Weight of total filterable PM, regardless of size, per unit weight of grain throughput.
[c] Condensible PM is material collected in the impinger portion of a PM sampling train.
[d] Weight of PM $\leq$ 10μm in aerodynamic diameter per unit weight of grain throughput.
[e] Reference 38. Feed shipping emission factor based on data for loading of bulk feed (not pellets).
[f] See emission factors for grain elevators, Table 9.9.1-1.
[g] PM-10 test data are not available. PM-10 emission factors can be estimated by taking 50 percent of the filterable PM emission factor.
[h] Mean of two values from References 26 and 27.
[j] Mean of two B-rated values from References 28, 29, and 30.
[k] Reference 31.
[m] Includes column and pan dryers.
[n] Mean of 11 A-, B-, and C-rated values from References 26, 27, 31, and 32.
[p] Mean of three B- and C-rated values from References 26 and 32.
[q] Mean of two B-rated values from References 29, 30, and 31.
[r] Equivalent to triple cycle or modern high efficiency cyclone.
[s] Reference 2.
[t] Mean of five D-rated values from Reference 34.
[u] Reference 35.
[v] Reference 36.
[w] Mean of two values from References 36 and 37. Value converted from bushels to tons using a conversion factor of 50 bu/ton.
[x] Reference 37.
[y] PM-10 test data are not available. PM-10 emission factors can be estimated by taking 100 percent of the filterable PM emission factor.

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E-2 Donaldson Torit Filter Emission Guarantee

Donaldson
Filtration Solutions

Donaldson Company, Inc.
Industrial Air Filtration
1400 West 94th Street
Bloomington, MN
55431-2370

Mailing Address:
P.O. Box 1299
Minneapolis, MN
55440-1299 U.S.A.

Tel 800.365.1331
Fax 952-887-3377
www.Donaldson.com
www.donaldsontorit.com

To: Bratney Equipment

From: Chrissy Klocker
Donaldson Torit
Subject: Donaldson Torit Ultra-Web® PowerCore® Filter Emissions Statement

Date: September 11, 2015

In regards to your request for a stated efficiency as it relates to Donaldson Torit Ultra-Web media.

The efficiency of a media depends on many variables such as, inlet loading, dust cake, cleaning capabilities of the dust collector, outlet emissions and so on. Because of this, it is difficult for us to state one specific efficiency level for our media.

Instead, Donaldson will guarantee an outlet emissions level that can be tested based on the EPA Method 5i testing standards. General particulate emissions standards suggest an outlet emissions level of 5 milligrams per cubic meter or 0.002 grains per dry standard cubic foot. Therefore, the maximum average total particulate emissions in the discharge gas stream from a Donaldson Torit Collector using Donaldson Torit Ultra-Web filters will not exceed 0.002 grains per dry standard cubic foot over the life of the media. While this level of outlet emission performance is sufficient for many industries, it does not necessarily represent the emission performance capability of Donaldson Dust Collectors. Rather, it represents a commonly acceptable level of emissions which can be readily verified using common stack emission monitoring methods.

Please let me know if you have any questions.

Regards,

Chrissy Klocker
Donaldson Company Inc.
Application Engineering Manager
952-887-3446
chrissy.klocker@donaldson.com

E-3 Pellet Mill Cooler PM Source Test- 4/27/2000

Pellet Mill Cyclone PM Emission Factor Information
April 27, 2000 Source Test Information

A
P
T

Executive Summary

Air Pollution Testing (APT) was contracted by JBR Environmental Consultants, Inc. to conduct a source emissions test on the Pellet Mill Cyclone Exhaust Stack at the Great Western Malting Company located in Pocatello, Idaho. The purpose of the testing program was to determine the emission levels of particulate matter less than 10 µm (PM_{10}) and condensible particulate matter (CPM).

Stack gas samples were pulled through an in-stack cyclone with a 10 µm cut-point to separate out particulate matter greater than 10 µm in diameter (PM_{10}^{+}), across a tared glass fiber filter to collect PM_{10}, and through a series of chilled condenser bottles to collect CPM. The presence of cyclonic flow at the sampling location required pre-approved deviations to EPA Method 201A test procedures be followed. These changes are explained in detail in the body of this report. A total of three approximately 60-minute sampling runs for the determination of PM_{10} and CPM emissions were conducted on April 27, 2000. The testing was conducted to demonstrate cyclone efficiency.

The results of the testing are summarized in the table below.

Great Western Malting : Pellet Mill Cyclone Exhaust Emissions Testing Results	
	Average Test Data
Stack Flow (dscfm)(1)	7,330
Emission Rate Data	
PM_{10} (lb/hr) (2)	0.16
PM_{10} (lb/ton)(3)	0.066

1. Dry standard cubic feet per minute (adjusted for cyclonic flow)
2. Pounds per hour
3. Pounds per ton (process feed rate)

1. Introduction

Air Pollution Testing (APT) was contracted by JBR Environmental Consultants, Inc. to conduct a source emissions test on the Pellet Mill Cyclone Exhaust Stack at the Great Western Malting Company located in Pocatello, Idaho. The purpose of the testing program was to determine the emission levels of particulate matter less than 10 μm (PM_{10}) and condensible particulate matter (CPM).

The testing was conducted to verify the cyclone efficiency by measuring emission levels of PM_{10} exiting the stack. A total of three 60-minute sampling runs for the determination of PM_{10} and CPM emissions were conducted on April 27, 2000.

Personnel involved in the test program are listed in Table 1.1.

Great Western Malting: Pellet Mill Cyclone Exhaust Emissions Testing Program Contact Personnel		
Name, Title	*Company, Affiliation Address*	*Phone, FAX*
Mr. Steve VanOotegham, Senior Environmental Scientist	JBR Environmental Consultants, Inc. 3140 S. Bayou Bar Ave. 83642 Meridian, ID 83680	208-888-6166, 208-888-5575
Mr. Tom Anderson, Permit Engineer	Idaho DEQ 1410 North Hilton Boise, ID 83706	208-373-0312
Mr. Steve Brammer, Maintenance Lead	Great Western Malting 1666 Kraft Pocatello, ID 83204-0007	208-234-1260, 208-233-3045
Mr. Jason Hill, Senior Project Manager	Air Pollution Testing, Inc. 1959 South 4130 West Unit B Salt Lake City, UT 84104	801-974-0481, 801-974-0483

Table 1.1 : Emissions Testing Program Contact Personnel

2. Methods

APT tested in accordance with the following U.S. Environmental Protection Agency (EPA) source emissions test methods.

- *Method 1 - Sample and Velocity Traverses for Stationary Sources*
- *Method 3 - Gas Analysis for the Determination of Dry Molecular Weight*
- *Method 201A - Determination of Particulate Matter (10 Microns or Less) Emissions from Stationary Sources*
- *Method 202 - Determination of Condensible Particulate Matter Emissions from Stationary Sources*

Methods 1 and 3 are referenced in *40 CFR Part 60, Appendix A*.

Methods 201A and 202 are referenced in *40 CFR Part 51, Appendix M*.

3. Test Program Summary

The test program determined all emission parameters in Table 3.1 on the following page. Stack gas samples were pulled through an in-stack cyclone with a 10 μm cut-point to separate out particulate matter greater than 10 μm in diameter (PM_{10}^{+}), across a tared glass fiber filter to collect PM_{10}, and through a series of chilled condenser bottles to collect CPM. The results of the testing are presented in Table 5.1 in this Test Report.

The sampling location consisted of a vertical stack with two sampling ports arranged 90 degrees apart in accordance with EPA Method 1. The sampling ports were located directly downstream of the pellet mill cyclone. The sampling location did not meet EPA method 1 requirements for up/down stream disturbance distances. This issue was addressed with the Idaho DEQ prior to testing. An alternative procedure was approved and is addressed in Section 4 of this test report. Diagram 3.1 provides a schematic of the sampling location and sampling points.

Great Western Malting: Pellet Mill Cyclone Exhaust Sampling and Analytical Methods Summary			
Parameter	*Sampling Method*	*Analytical Method*	*Laboratory*
Gas flow	Method 201A	S-type pitot, draft gauge, and thermocouple	APT, On-Site
O_2 / CO_2	Method 3	Fyrite apparatus	
H_2O	Method 201A	gravimetric and volumetric	
PM and PM_{10}	Method 201A	gravimetric	APT Wheat Ridge, Colorado
CPM	Method 202	gravimetric	

Table 3.1 : Sampling and Analytical Methods Summary

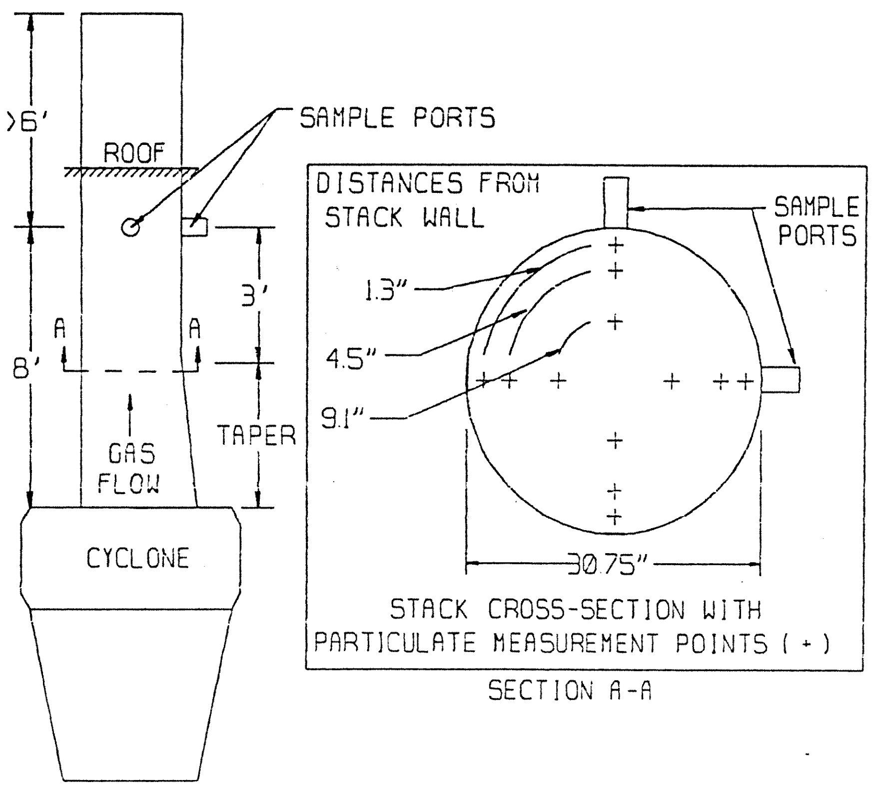

Diagram 3.1 : Sampling Location Schematic (not to scale)

4. Test Method Details

PM_{10}, CPM and Stack Gas Flow Rate

PM_{10}, CPM and volumetric flow rate were determined in accordance with EPA Methods 1, 3, 201A, 202 and EMTIC guideline document GD-008 (testing in cyclonic flow). A summary of the testing parameters is provided in *Appendix 1 - Testing Parameters / Sample Calculations*. Copies of the field and laboratory data sheets are located in *Appendix 2 - Field and Laboratory Data*.

The presence of cyclonic flow at the sampling location required an alternative test procedure to be performed called the Alignment Approach (EMTIC GD-008). Each sampling period consisted of conducting a temperature and differential pressure traverse of the stack with a K-type thermocouple and a standard pitot tube before and after each run. This was performed by positioning the bare pitot (no nozzle) in the stack at the method 1 sampling points and rotating it until a null reading was observed. At the "null" position the angle was recorded and then the pitot tube was rotated 90 degrees where a flow measurement was made. The values obtained during the pre-test velocity traverse were then used for the emission test. The nozzle of the PM_{10} cyclone was adjusted at each sampling point to correspond to the angle used to measure the stack flow during the pre-test. After each run a post-test velocity traverse was performed to verify pre-test measurements. Because consecutive runs were performed, the post-test traverse of the prior run was used as the pre-test for the subsequent run.

The difference between pre and post velocity traverses varied from run to run. Before run one, the flow profile was higher and more erratic. After runs one, two, and three, the overall flow profile became more stable The pellet mill cyclone was turned on just prior to testing, and it is possible that over time the process reached a more stable state of operation. Because the flow profile was so varied prior to run one, pre-test parameters were more difficult to determine. The result was a difference of >5% average flow, a >5° average null angle (as per EMTIC GD-008), and a cyclone cut size that was 0.1 μm larger than acceptable (as per method 201A) for run one. A less erratic flow profile, combined with pre-test adjustments made to runs two and three offset the problems encountered during run one. Run two and three afterwards met all method 201A and cyclonic flow requirements.

During the actual test runs, a gas sample was extracted at a constant flow rate passing through a stainless steel nozzle, an in-stack cyclone, a series of 4 chilled glass impingers, and through a calibrated dry gas meter. Diagram 4.1 provides a schematic of the sampling train.

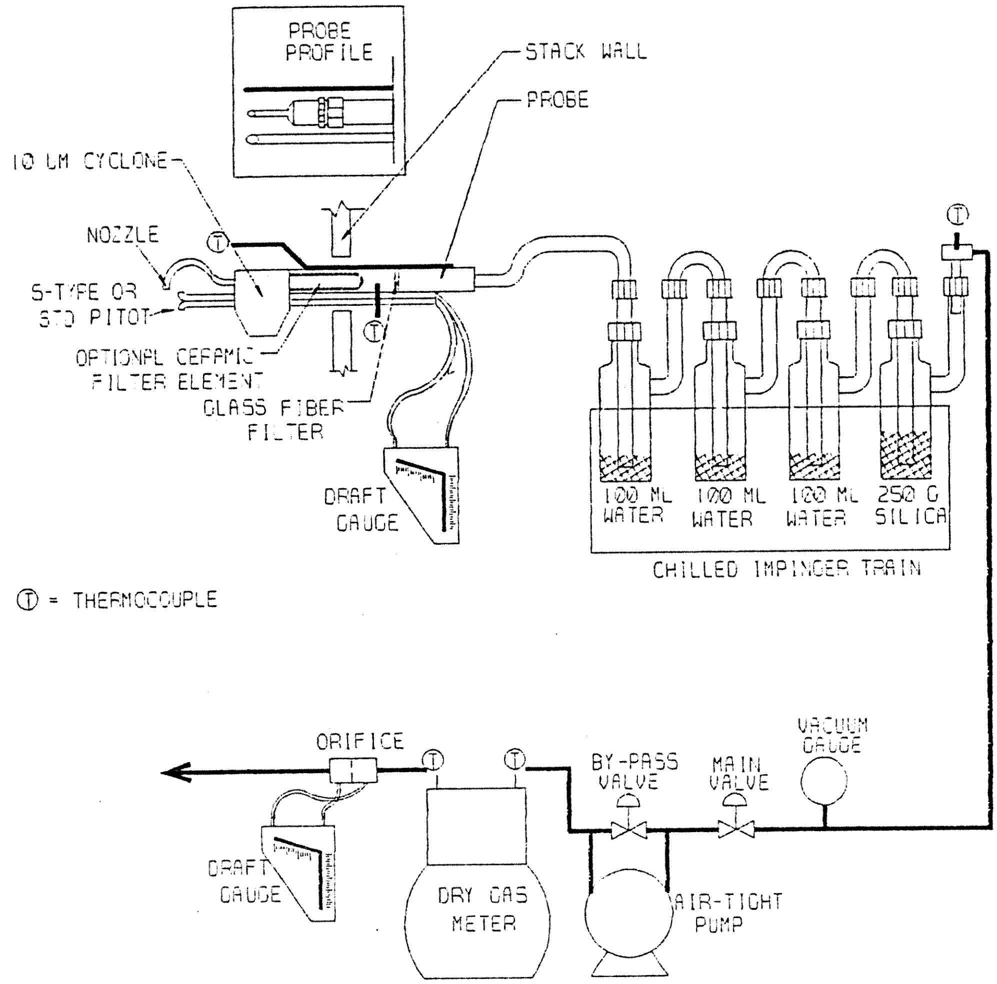

Diagram 4.1 Methods 1- 4, 201A & 202 Sampling Train

Prior to sampling, the first three impingers were each seeded with 100 milliliters of water. The fourth impinger was seeded with approximately 250 grams of dried silica gel. Following sampling, the moisture gain in the impingers was measured volumetrically and gravimetrically to determine the moisture content of the stack gas. Oxygen (O_2) and carbon dioxide (CO_2) content were measured using a Fyrite instrument. The filter and a series of acetone rinses of the connecting hardware from the back of the cyclone to the filter were quantitatively recovered for gravimetric analysis to determine the PM_{10} content of the stack gas. The impinger contents were extracted with duplicate 75 milliliter methylene chloride rinses and the aqueous and organic fractions taken to dryness to determine the CPM content of the stack gas. The aqueous fraction was evaporated over low heat (<200°F) and the organic fraction was evaporated at room temperature.

All of the collected data were combined to calculate the stack gas velocity and volumetric flow rate in units of feet per second (ft/sec), actual cubic feet per minute (acfm), dry standard cubic feet per minute (dscfm), and dscfm corrected for cyclonic flow. Particulate emissions were calculated in units of lb/hr and pounds per ton (lb/tn).pounds per hour (lb/hr). The raw data are summarized in *Appendix 1 - Testing Parameters / Sample Calculations*.

5. Results

The results of the testing are presented in Table 5.1 on the following page. Any testing parameters not found in the table may be found in *Appendix 1 - Testing Parameters / Sample Calculations* at the back of this report.

The following terms and abbreviations are used in the table.

Temp. - temperature

dscfm - dry standard (68°F, 1 atm.) cubic feet per minute

O_2 (%vd) - stack gas oxygen content (dry volume percent)

CO_2 (%vd) - stack gas carbon dioxide content (dry volume percent)

H_2O (%vw) - stack gas water vapor content (wet volume percent)

lb/hr - pounds per hour

lb/tn - pounds per ton (of product)

Great Western Malting: Pellet Mill Cyclone Exhaust Emissions Testing Results : 4/27/00				
	Run #1	*Run #2*	*Run #3*	***Averages***
Start Time	12:07	14:39	16:31	
Stop Time	13:11	15:46	17:37	
Stack Temp. (°F)	137	132	127	**132**
Pellet Mill Feed Rate (tons/hr)	2.4	2.4	2.4	**2.4**
Stack Flow (dscfm)	8,591	6,508	6,892	**7,330**
O_2 (%vd)	20.9	20.9	20.9	**20.9**
CO_2 (%vd)	1.0	1.0	1.0	**1.0**
H_2O (%vw)	1.3	2.0	0.8	**1.4**
Emission Rate Data				
PM_{10} (lb/hr)	0.17	0.13	0.18	**0.16**
PM_{10} (lb/ton)	0.070	0.055	0.073	**0.066**

Table 5.1 : Emissions` Testing Results
Pellet Mill Cyclone Exhaust Stack

E-4 Kiln PM Source Test- 10/14/2005

Kiln PM Emission Factor Information
October 14, 2005 Source Test Report

AIR
POLLUTION
TESTING, INC.
DENVER, DURANGO, SALT LAKE CITY

Source Emissions Test Report for Bridgewater Group and Great Western Malting Pocatello, Idaho

Malt Kiln Building Vent PM Emissions

Test Report prepared for:
Ms. Candice Hatch
Bridgewater Group, Inc.
4500 SW Kruse Way, Suite 110
Lake Oswego, Oregon 97035

Report Prepared by:

Karl Breuer
Technical Writer

Test Date:
October 14, 2005

APT Project: POC5325

DENVER OFFICE
5530 Marshall Street
Arvada, CO 80002
(303) 420-5949
FAX (303) 420-5920
(800) 268-6213

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P
T

Table of Contents

1. Introduction

The purpose of the testing program was to determine the emission levels of particulate matter (PM) from the malt kiln currently in service at the Great Western Malting facility.

The data was used to assess the accuracy of an emission factor for PM emissions from the malt kiln. Personnel involved in the test program can be found in Table 1.1 below.

Bridgewater Group / Great Western Malting Emissions Testing Program Personnel Contact List		
Name, Title	*Address*	*Phone, FAX*
Ms. Candice Hatch	Bridgewater Group, Inc. 4500 SW Kruse Way, Suite 110 Lake Oswego, OR 97035	503-675-5252 x5 503-675-1960 fax
Mr. Steve Brammer	Great Western Malting Pocatello, ID	208-234-1260 x112
Mr. Dan Pitman	Idaho DEQ – State Office 1410 North Hilton Boise, ID 83706	208-373-0502
Mr. Mike Corrigan, Project Manager	Air Pollution Testing, Inc. 1959 South 4130 West, Unit B Salt Lake City, Utah 84104	801-974-0481, 801-974-0483

Table 1.1: Emissions Testing Program Contact Personnel

2. Test Results Summary

The results of the testing are summarized in Table 2.1 on the following page. Any emission parameters not found in the table may be found in *Appendix 1- Test Parameters / Sample Calculations*. The following terms and abbreviations are used in the table:

- %vd – diluent concentration, dry volume percent
- %vw – moisture content, wet volume percent
- Temp. (°F) – temperature, degrees Fahrenheit
- dscfm – gas flow rate, dry standard (one atmosphere, 68°F) cubic feet per minute
- lb/hr – pollutant mass emission rate, pounds per hour
- gr/dscf – PM mass emission rate, grains per dry standard cubic foot
- lb/tons of malt – pollutant mass emission rate, pounds per tons of malt produced
- lb/605 min. cycle – pollutant mass emission rate, pounds per 605 minute production cycle

Bridgewater Group / Great Western Malting, Pocatello, Idaho Test Results Summary: Malt Kiln Building Vent, October 14, 2005				
	"A" Train	"B" Train	"C" Train	Average
Start Time	7:50	7:50	7:50	
Stop Time	17:55	17:55	17:50	
O_2 (%vd)	20.9	20.9	20.9	20.9
CO_2 (%vd)	0.0	0.0	0.0	0.0
H_2O (%vw)	3.1	3.3	3.0	3.2
Production (tons)	182.9	182.9	182.9	182.9
Stack Temp (˚F)	79	79	79	79
Gas Flow (dscfm)	504,043	503,204	504,513	503,920
% Isokinetic	103.1	102.5	101.2	102.3
Emissions Data				
PM (lb/hr)	0.88	0.72	0.95	0.85
PM (lb/605 min. cycle)	8.90	7.26	9.60	8.59
PM (gr/dscf)	0.00020	0.00017	0.00022	0.00020
PM (lb/tons of malt)	0.049	0.040	0.052	0.047

Table 2.1 Results Summary

3. Methods

APT tested in accordance with the following U.S. Environmental Protection Agency (USEPA) source emission test methods referenced in 40 CFR Part 60, Appendix A.

- *Method 1 – Sample and Velocity Traverses for Stationary Sources*
- *Method 3 – Gas Analysis for the Determination of Dry Molecular Weight*
- *Method 5 – Determination of Particulate Emissions from Stationary Sources*

4. Test Program Summary

The emissions testing program determined all emissions parameters detailed in Table 4.1.

Malt kiln emissions are discharged to the atmosphere through a large roof vent, measuring 8'10" x 188'3". The roof vent exhaust location does not meet the sampling location selection criteria outlined in EPA Method 1; there are effectively no upstream or downstream distances to flow disturbances. Particulate matter sampling was conducted over a 12 x 2 sampling point matrix from within the vent discharge assembly, above a grating, in an area enclosed by tapering walls. The full 24-point sampling matrix was not completed, but instead 22 points were sampled since the sampling time was abbreviated to avoid the startup moisture surge that could have complicated the testing. The malt kiln operated for the normal 11 hour production cycle. A diagram of the test location is provided in *Appendix 5 – Schematics*. The three Method 5 sampling trains were operated side-by-side, sampling for 27.5 minutes at each sampling point. The gas velocity was measured at each sampling point with a vane anemometer and the anemometer velocity at each point was used to back-calculate the equivalent square root of the pressure differential as read on an oil-filled manometer. The anemometer data was used to determine mass emissions and for calculation of sampling train isokinetics.

Three sampling trains were operated simultaneously for 605 minute test runs. This extended sampling time was necessary to provide quantitative results based on flow rates, sample volumes, and kiln throughput. Integrated samples were collected for off-site analysis to determine emission concentrations of PM. Concurrently collected stack gas flow data was used to calculate mass emission rates from emission concentrations.

Bridgewater Group / Great Western Malting Sampling and Analytical Methods Summary			
Emission Parameter	*EPA Method*	*Analytical Method*	*Laboratory*
gas flow	Methods 1, 5 [(1)]	thermocouple, anemometer	APT, on-site
O_2, CO_2	Method 3	fyrite apparatus	
moisture (H_2O)	Method 5	gravimetric	
PM	Method 5	Gravimetric	APT, off-site
[(1)] – An anemometer was used in place of a pitot tube to allow accurate velocity determinations at the low velocities.			

Table 4.1: Sampling and Analytical Methods Summary

5. Test Method Details

Particulate emissions were determined in approximate accordance with EPA Method 5. A total of three integrated samples for stack gas PM content analysis were collected over a one day period. The three samples were collected simultaneously, each over a single 605 minute sample period.

Each sampling period consisted of conducting a temperature and velocity traverse of the stack over a 24-point grid using a K-type thermocouple and a vane anemometer. Concurrent with each traverse, a sample of gas was extracted at each point at an isokinetic flow rate. The gas sample passed through an in-stack nozzle, a heated stainless steel probe, across a tared glass fiber filter, through a series of chilled glass impingers, and through a calibrated dry gas meter. The heated Method 5 filter enclosure was maintained at stack temperature, rather than 250 degrees F, in order to minimize the risk of filter mass loss, and to avoid volatilization of any particulate matter. Please see *Appendix 5 – Schematics* for a diagram of the EPA Method 5 sampling train.

Following sampling, the moisture gain in the impingers was measured gravimetrically to determine the moisture content of the stack gas. A fyrite apparatus was used to confirm the essentially ambient diluent levels of the gas (20.9% oxygen, 0.0% carbon dioxide). The filter and a series of acetone rinses of the nozzle, probe and front-half connecting hardware including the front half filter bell housing was quantitatively recovered for gravimetric analysis to determine the PM content of the stack gas.

The above data was combined with concurrently collected flow, diluent and production data to calculate the particulate concentration and emission rates in units of grains per dry standard cubic foot (gr/dscf), pounds per hour (lb/hr), pounds per production cycle, and pounds per ton of malt produced.

Appendix 1

Testing Parameters / Sample Calculations

Great Western Malting
Pocatello, Idaho
Kiln Building Vent
10/14/2005
EPA Method 5: Determination of Particulate Emissions from Stationary Sources

Field Data	"A" Train	"B" Train	"C" Train	Average	
start time	7:50 AM	7:50 AM	7:50 AM		
stop time	5:55 PM	5:55 PM	5:55 PM		
production (tons of malt)	182.9	182.9	182.9	182.9	
sample volume (ft^3)	420.153	419.554	466.094	435.267	
sampling time (minutes)	605.0	605.0	605.0	605.0	
stack temp. (°F)	79	79	79	79	
meter temp. (°F)	68	72	77	72	
barometric pressure (mbar)	864	864	864	864	
barometric pressure (" Hg)	25.51	25.51	25.51	25.51	
stack pressure (" H_2O)	0.0	0.0	0.0	0.0	
oxygen (%vd)	20.9	20.9	20.9	20.9	
carbon dioxide (%vd)	0.0	0.0	0.0	0.0	
moisture (g)	247.4	261.4	258.6	255.8	
orifice setting delta H (" H_2O)	1.34	1.34	1.49	1.39	
average (delta P)^{½} (" H_2O)^{½}	0.101	0.101	0.101	0.101	
meter box Y_d (unitless)	0.998	0.999	0.992	0.996	
pitot tube constant (unitless)	0.84	0.84	0.84	0.84	
nozzle diameter (inches)	0.590	0.590	0.620	0.600	
stack diameter (inches) *	552.2	552.2	552.2	552.2	*Reagent Blank*
Laboratory Data					
mass particulate front half (g)	0.00270	0.00240	0.00365	0.00292	*0.00005*
mass particulate filter (g)	0.00205	0.00145	0.00190	0.00180	*NA*
Calculations					
sample volume (dscf)	358.801	355.952	389.177	367.977	
moisture volume (dscf)	11.645	12.304	12.172	12.041	
moisture content (%/100)	0.031	0.033	0.030	0.032	
molecular weight (dry)	28.84	28.84	28.84	28.84	
molecular weight (actual)	28.50	28.47	28.51	28.49	
gas velocity (ft/sec)	6.2	6.2	6.2	6.2	
gas flow (acfm)	623,007	623,241	622,876	623,041	
gas flow (dscfm)	504,043	503,204	504,513	503,920	
gas flow (lb/hr)	2,307,399	2,306,532	2,307,885	2,307,272	
% isokinetic	103.1	102.5	101.2	102.3	
F½ PM (lb/hr)	0.88	0.72	0.95	0.85	
F½ PM (lb/605-min cycle)	8.90	7.26	9.60	8.59	
F½ PM (lb/ton malt)	0.049	0.040	0.052	0.047	
F½ PM (gr/dscf)	0.00020	0.00017	0.00022	0.00020	

* - Diameter of equal-area round stack.

EPA Method 5 : Determination of Particulate Emissions from Stationary Sources
Great Western Malting — Malt Kiln, Run #1, October 14, 2005
Sample Calculations

$$\text{sample volume (scf)} = \frac{(17.64)\cdot V_M\cdot Y_D\cdot\left(P_B+\frac{\Delta H}{13.6}\right)}{T_M+460}$$

$$= \frac{(17.64)\cdot(420.153)\cdot(0.995)\cdot\left[(25.51)+\frac{(1.34)}{13.6}\right]}{[(68)+460]}$$

$$= 358.801$$

$$\text{moisture volume (scf)} = (0.04707)\cdot V_{LC}$$

$$= (0.04707)\cdot(247.4)$$

$$= 11.645$$

$$\text{moisture content (\%/100)} = \frac{V_{W(STD)}}{\left(V_{M(STD)}+V_{W(STD)}\right)}$$

$$= \frac{(11.645)}{[(358.801)+(11.645)]}$$

$$= 0.031$$

$$\text{molecular weight, dry (grams/mole)} = (0.440)\cdot(\%CO_2)+(0.320)\cdot(\%O_2)+(0.280)\cdot(\%N_2+\%CO)$$

$$= (0.440)\cdot(0.0)+(0.320)\cdot(20.9)+(0.280)\cdot[(79.1)+(0.0)]$$

$$= 28.84$$

$$\text{molecular weight, actual (grams/mole)} = M_D\cdot(1-B_{WS})+(18.0)\cdot B_{WS}$$

$$= (28.84)\cdot[1-(0.031)]+(18.0)\cdot(0.031)$$

$$= 28.50$$

$$\text{gas velocity (ft/sec)} = (85.49)\cdot C_P\cdot\sqrt{\Delta P}_{AVG}\cdot\sqrt{\frac{T_S+460}{\left[P_B+\frac{P_S}{(13.6)}\right]\cdot M_A}}$$

$$= (85.49)\cdot(0.84)\cdot(0.101)\cdot\sqrt{\frac{(79)+460}{\left[(25.51)+\frac{(0.0)}{(13.6)}\right]\cdot(28.50)}}$$

$$= 6.2$$

EPA Method 5 : Determination of Particulate Emissions from Stationary Sources
Great Western Malting — Malt Kiln, Run #1, October 14, 2005
<u>Sample Calculations (continued)</u>

$$\text{gas flow (acfm)} = (60)\cdot A_S \cdot V_S$$

$$= (60)\cdot(1{,}663.1)\cdot(6.2)$$

$$= 623{,}007$$

$$\text{gas flow (dscfm)} = (60)\cdot(1-B_{WS})\cdot V_S \cdot A_S \cdot \frac{T_{STD}\cdot\left[P_B + \dfrac{P_S}{(13.6)}\right]}{(T_S + 460)\cdot P_{STD}}$$

$$= (60)\cdot[1-(0.031)]\cdot(6.2)\cdot(1{,}663.1)\cdot\frac{(528)\cdot\left[(25.51) + \dfrac{(0.0)}{(13.6)}\right]}{[(79)+460]\cdot(29.92)}$$

$$= 504{,}043$$

$$\text{particulate emissions (lb/hr)} = \frac{M_T \cdot F_{DSCFM}\cdot[60\,(\min/hr)]}{V_{M(STD)}\cdot[453.593\,(g/lb)]}$$

$$= \frac{(0.00475)\cdot(504{,}043)\cdot(60)}{(358.801)\cdot(453.593)}$$

$$= 0.88$$

$$\text{particulate emissions (gr/dscf)} = \frac{M_T}{V_{M(STD)}}\cdot[15.43\,(grains/gram)]$$

$$= \frac{(0.00475)}{(358.801)}\cdot(15.43)$$

$$= 0.00020$$

EPA Method 5 : Determination of Particulate Emissions from Stationary Sources
Great Western Malting — Malt Kiln, Run #1, October 14, 2005
Sample Calculations (continued)

$$\% \text{ isokinetic} = \frac{(100)\cdot(T_S+460)\cdot\left[(0.002669)\cdot V_{LC}+\left(\frac{V_M\cdot Y_D}{(T_M+460)}\right)\cdot\left(P_B+\frac{\Delta H}{13.6}\right)\right]}{(60)\cdot\Theta\cdot V_S\cdot\left(P_B+\frac{P_S}{13.6}\right)\cdot\frac{\left[\pi\cdot\left(\frac{D_N}{12}\right)^2\right]}{4}}$$

$$= \frac{(100)\cdot[(79)+460]\cdot\left\{(0.002669)\cdot(247.4)+\left[\frac{(420.153)\cdot(0.998)}{[(68)+460]}\right]\cdot\left[(25.51)+\frac{(1.34)}{13.6}\right]\right\}}{(60)\cdot(605.0)\cdot(6.2)\cdot\left[(25.51)+\frac{(0.0)}{13.6}\right]\cdot\frac{\left\{\pi\cdot\left[\frac{(0.590)}{12}\right]^2\right\}}{4}}$$

$$= 103.1\%$$

Variables and Abbreviations

acfm - actual cubic feet per minute

A_S - stack area (square feet)

B_{WS} - moisture content of the gas (wet volume percent/100)

%CO - carbon monoxide content of the gas (dry volume percent)

%CO_2 - carbon dioxide content of the gas (dry volume percent)

D_N - diameter of the nozzle (inches)

F_{DSCFM} - gas flow (dry standard cubic feet per minute, where standard = 29.92 inches Hg and 68°F)

gr/dscf - grains per dry standard cubic foot

ΔH - pressure differential at dry gas meter exit orifice (inches water)

lb/hr - pounds per hour

lb/ton - pounds per ton

M_A - molecular weight of the wet gas (grams per mole)

M_D - molecular weight of the dry gas (grams per mole)

M_T - total mass particulate recovered (grams)

%N_2 - nitrogen content of the gas (dry volume percent)

EPA Method 5 : Determination of Particulate Emissions from Stationary Sources
Great Western Malting — Malt Kiln, Run #1, October 14, 2005
Variables (continued)

$\%O_2$ - oxygen content of the gas (dry volume percent)

$\sqrt{\Delta P}_{AVG}$ - average square root of the stack gas pitot differential pressure (inches water)

P_B - barometric pressure (inches mercury)

P_S - stack pressure relative to barometric pressure (inches water)

P_{STD} - standard pressure (29.92 inches mercury)

Θ - total sampling time (minutes)

T_M - average dry gas meter temperature (°F)

T_S - average stack temperature (°F)

T_{STD} - standard temperature (528 °R)

V_{LC} - volume of moisture collected as a liquid (milliliters)

V_M - volume indicated on dry gas meter (uncorrected actual cubic feet)

V_{MSTD} - volume of gas through dry gas meter (corrected dry standard cubic feet)

V_S - stack gas velocity (feet per second)

V_{WSTD} - volume of moisture collected as a gas at standard conditions (standard cubic feet)

Y_D - dry gas meter calibration factor (unitless)

Appendix 2

Field Data

KILN OUTLET R1 Mtd 5 A 10/14/05 PAGE 1 of 2

Air Pollution Testing, Inc. : Isokinetic Sampling Datasheet

APT Job #: POC 5325	Date: 10/14/05	CO2 (%): 20.9	O2 (%): 0.0
Location: KILN OUTLET A	Operator: DJ, MC	Assumed Moisture (%): 1	Barometric Pressure (mbar): 864
Run #: 1	Probe ID:	Ambient Temperature (oF): 50	Probe Material: SS
Meter Box Yd: 0.998	Pitot Tube Coefficient:	Probe Length (ft): 3'	Filter Temperature (oF): STACK
Sample Box ID: ———	Meter Box ID: MS-15	Probe Temperature (oF): STACK	Moisture (grams): 247.4
Meter DHG: 1.77	K Factor: 125.85	Nozzle Diameter (in): 0.590	Start Time: 0750
Pre-Test Pitot Leak Check: ✓	Post-Test Pitot Leak Check: ✓	Static Pressure (" H2O): Ø	Stop Time: 1755
Pre-Test Pump Leak Check: 0.000 @ 16" Hg	Post-Test Pump Leak Check: 0.00 @ 16" Hg	Filter ID: 050235	Method: 5

Schematic of Stack:

189.2
~~16.73~~

Traverse Point	Sampling Time (minutes)	Vacuum (" Hg)	Velocity Head (" H2O)	Orifice Setting (" H2O)	Stack Temp. (oF)	Meter Volume (ft3) Initial Volume	Probe Temp (oF)	Filter Temp. (oF)	Meter Temp. Inlet (oF)	Meter Temp. Outlet (oF)	Condenser Temp. (oF)	XAD Temp. (oF)	K (ft3/min)	Pv (ft3)
						465.748								6.88
1-1	27.5	3	.0072	.91	69	481.75	STACK	STACK	45	45	36			81.54
2	55.0	6	.012	1.5	71	502.5			52	46	37			[illegible]
3	82.5	4	.0081	1.0	72	519.4			54	48	39		1:50	19.54
4	110.0	8	.014	1.8	73	541.8			56	49	41		2:17.5	41.92
5	131.5	3	.003	.40	74	552.3			59	53	41		2:45	52.28
6	165.0	7	.016	2.0	76	576.3			62	56	42		3:12.5	76.21
7	192.5	8	.018	2.3	76	601.6			68	59	41		3:40	0159
8	220.0	8	.016	2.0	78	625.4			73	64	43		4:07.5	25.52
9	247.5	4	.006	.76	78	640.2			76	68	44		4:35	40.17
10	275.0	4	.007	.88	81	656.0			81	75	44		5:02.5	56.0
11	302.5	5	.009	1.1	83	673.9			83	80	45		5:30	7394
12	330.0	5	.008	1.0	82	690.7			86	81	46			9086
2-1	357.5	6	.014	1.8	84	713.2			82	80	44			13.25
2	385.0	6	.012	1.5	84	733.9			81	79	44			33.98
3	412.5	5	.010	1.3	86	752.9			80	77	45			52.9
4	440.0	4	.007	.88	83	768.7			79	75	44			6873
5	467.5	6	.013	1.6	84	790.3			79	75	44	7:47.5		9030
6	495.0	8	.018	2.3	84	815.7			79	74	45			1568
7	522.5	5	.004	1.1	82	833.63			78	74	45			33.63
8	550.0	8	.012	1.5	81	854.4			78	74	45			54.36
number	total	maximum	average root	average	average	difference	minimum	minimum	average		maximum	maximum	Reviewers Signature:	

Stack ID (inches): 552.24"
Upstream Disturbance (inches): 149"
Downstream Disturbance (inches): 2"
# of points:

Moisture Determination

Imp. #	Tare	Final	Gain
1	411.8	478.4	
2	400.3	491.3	
3	298.1	366.9	
4	564.6	585.6	
	1674.8	1922.2	247.4

Notes:

KILN OUTLET R1 Mtd 10/14/05 PAGE 2 of 2

Air Pollution Testing, Inc.: Isokinetic Sampling Datasheet

APT Job #:	POC 5325	Date:	10/14/05	CO2 (%):	20.9	O2 (%):	0.0
Location:	KILN OUTLET "A"	Operator:	DJ/MC	Assumed Moisture (%):	1	Barometric Pressure (in.Hg):	8.64
Run #:	1 cont	Probe ID:		Ambient Temperature (oF):	50	Probe Material:	SS
Meter Box Yd:	0.998	Pitot Tube Coefficient:	.84	Probe Length (ft):	3'	Filter Temperature (oF):	STACK
Sample Box ID:	—	Meter Box ID:	M5-15	Probe Temperature (oF):	STACK	Moisture (grams):	247.4
Meter DH@:	1.77	K Factor:	125.85	Nozzle Diameter (in):	0.590	Start Time:	750
Pre-Test Pitot Leak Check:	✓	Post-Test Pitot Leak Check:	✓	Static Pressure (" H2O):	0	Stop Time:	1755
Pre-Test Pump Leak Check:	0.00 @ 16" Hg	Post-Test Pump Leak Check:	0.00 @ 16" Hg	Filter ID:	050235	Method:	5

Schematic of Stack:

Traverse Point	Sampling Time (minutes)	Vacuum (" Hg)	Velocity Head (" H2O)	Orifice Setting (" H2O)	Stack Temp. (oF)	Meter Volume (ft3) Initial Volume 854.4	Probe Temp (oF)	Filter Temp. (oF)	Meter Temp. Inlet (oF)	Meter Temp. Outlet (oF)	Condenser Temp. (oF)	XAD Temp. (oF)	Ki (ft3/min)	Pv (ft3)
2-9	577.5	4	.008	1.0	81	871.3	STACK	STACK	78	74	45			71.28
10	605.0	4	.006	~~30~~	79	885.901			77	74	45			85.93
11	632.5													
12	660.0													
12	605.0	8	.10099	1.34	29	420.153	86	86	68		46			
number	total	maximum	average root	average	average	difference	minimum	minimum	average		maximum	maximum		

Stack ID (inches): 552.24"

Upstream Disturbance (inches): 149"

Downstream Disturbance (inches): 2"

# of points:

Moisture Determination

Imp. #	Tare	Final	Gain
1			
2			
3			
4			

Notes :

Reviewers Signature :

KILN OUTLET R1 ~~[illegible]~~ Mtd 5 10/14/05 PAGE 1of2

B

Air Pollution Testing, Inc.: Isokinetic Sampling Datasheet

APT Job #: POC 5325	Date: 10/14/05	CO2 (%): 20.9	O2 (%): 0.0
Location: KILN OUTLET "B"	Operator: DJ/MC	Assumed Moisture (%): 1	Barometric Pressure (mbar): 864
Run #: 1	Probe ID:	Ambient Temperature (oF): 50	Probe Material: SS
Meter Box Yd: 0.999	Pitot Tube Coefficient: .84	Probe Length (ft): 3'	Filter Temperature (oF): STACK
Sample Box ID: ———	Meter Box ID: MS-1	Probe Temperature (oF): STACK	Moisture (grams): 261.4
Meter DHQ: 1.78	K Factor: ~~128.72~~ 126.56	Nozzle Diameter (in): 0.590	Start Time: 0750
Pre-Test Pitot Leak Check: ✓	Post-Test Pitot Leak Check: ✓	Static Pressure ("H2O): ~~[illegible]~~	Stop Time: 1755
Pre-Test Pump Leak Check: 0.000 @ 16" Hg	Post-Test Pump Leak Check: 0.100 @ 15" Hg	Filter ID: 050114	Method: 5

Schematic of Stack

189.2

~~[illegible]~~

Traverse Point	Sampling Time (minutes)	Vacuum ("Hg)	Velocity Head ("H2O)	Orifice Setting ("H2O)	Stack Temp. (oF)	Meter Volume (ft3) Initial Volume	Probe Temp. (oF)	Filter Temp. (oF)	Meter Temp. Inlet (oF)	Meter Temp. Outlet (oF)	Condenser Temp. (oF)	XAD Temp. (oF)	Ki (ft3/min)	Pv (ft3)
						291.843	Stack	Stack						6.88
1-1	27.5	3	.0072	.91	69	302.80	~~[illegible]~~		47	47	37			02.82
2	55.0	6	.012	1.5	71	325.6			53	50	38			28.61
3	82.5	4	.0081	1.0	72	345.5			56	52	40			45.63
4	110.5	8	.014	1.8	73	368.0			59	54	41			68.01
5	137.5	3	.003	.40	74	378.4	✓		62	57	41			78.37
6	165.0	8	.016	2.0	76	402.4			65	59	42			02.30
7	192.5	9	.018	2.3	76	427.1			69	63	42			27.68
8	220.0	8	.016	2.0	78	451.7			74	66	44			51.61
9	247.5	4	.006	.76	78	466.3			80	72	45			466.?
10	275.0	4	.007	.89	81	482.1			85	80	44		82.09	76.84
11	302.5	5	.009	1.1	83	500.1			86	85	44			00.03
12	330.0	5	.008	1.0	82	516.9			83	81	45			16.95
2-1	357.5	6	.014	1.8	84	539.3			82	81	43			39.33
2	385.0	6	.012	1.5	84	560.1			82	81	44			60.05
3	412.5	5	.010	1.3	86	578.[illegible]			82	79	44			78.97
4	440.0	3	.007	.89	83	594.8			80	78	45			94.79
5	467.5	6	.013	1.6	84	616.3			79	76	44	749.5		16.36
6	495.0	9	.018	2.3	84	641.7			79	75	45			41.74
7	522.5	5	.009	1.1	82	659.7			78	75	44			59.69
8	550.0	6	.012	1.5	81	680.4			78	75	44			80.42
number	total	maximum	average root	average	average	difference	maximum	maximum	average		maximum	maximum	Reviewer's Signature	

Stack ID (inches): 552.24" (0.181)

Upstream Disturbance (inches): 149"

Downstream Disturbance (inches): 2"

of points:

Moisture Determination

Imp. #	Tare	Final	Gain
1	444.3	558.4	
2	455.5	449.7	
3	296.1	405.0	
4	556.4	600.6	
	1752.3	2013.7	261.4

Notes :

KILN OUTLET R1 (CON'T) Mtd B 10/14/05

Air Pollution Testing, Inc. : Isokinetic Sampling Datasheet

APT Job #:	POC 5325	Date:	10/14/05	CO2 (%):	20.9	O2 (%):	0.0
Location:	KILN	Operator:	DJ/MC	Assumed Moisture (%):		Barometric Pressure (mbar):	864
Run #:	1 CON'T	Probe ID:		Ambient Temperature (oF):	50	Probe Material:	~~STACK~~ SS
Meter Box Yd:	0.999	Pitot Tube Coefficient:		Probe Length (ft):	3'	Filter Temperature (oF):	STACK
Sample Box ID:	—	Meter Box ID:	MS-1	Probe Temperature (oF):	STACK	Moisture (grams):	261.4
Meter DH@:	1.78	K Factor:	126.56	Nozzle Diameter (in):	0.590	Start Time:	0750
Pre-Test Pitot Leak Check:	✓	Post-Test Pitot Leak Check:	✓	Static Pressure (" H2O):	Ø	Stop Time:	1755
Pre-Test Pump Leak Check:	0.00 @ 16" Hg	Post-Test Pump Leak Check:	0.00 @ 15" Hg	Filter ID:	050114	Method:	5

Schematic of Stack:

Traverse Point	Sampling Time (minutes)	Vacuum (" Hg)	Velocity Head (" H2O)	Orifice Setting (" H2O)	Stack Temp. (oF)	Meter Volume (ft3) Initial Volume 680.4	Probe Temp. (oF)	Filter Temp. (oF)	Meter Temp. Inlet (oF)	Meter Temp. Outlet (oF)	Condenser Temp. (oF)	XAD Temp. (oF)	Ki (ft3/min)	Pv (ft3)
2-9	577.5	4	.008	1.0	81	697.3	STACK	STACK	78	79	45			9.234
10	605.0	4	.006	.76	79	711.397			77	74	45			11.35
11	632.5													
12	660.0													
counter 22	total 6050	maximum 9	average root 0.100954	average 1.34	average 79	difference 419.554	minimum 86	maximum 86	average 72		maximum 45	maximum		

Stack ID (inches):

Upstream Disturbance (inches):

Downstream Disturbance (inches):

# of points:

Moisture Determination

Imp. #	Tare	Final	Gain
1			
2			
3			
4			

Notes:

Reviewers Signature:

C 1 of 2

Air Pollution Testing, Inc.: Isokinetic Sampling Datasheet

APT Job #: POCS325	Date: 10/14/05	CO2 (%): 20.9	O2 (%): 0.0
Location: Kiln Outlet C	Operator: DJ	Assumed Moisture (%): 1	Barometric Pressure (mbar): 864
Run #: 1	Probe ID:	Ambient Temperature (oF):	Probe Material: SS
Meter Box Yd: 0.992	Pitot Tube Coefficient: .84	Probe Length (ft): ~~5'~~ 3'	Filter Temperature (oF): STACK
Sample Box ID: ———	Meter Box ID: MS-20	Probe Temperature (oF): STACK	Moisture (grams): 258.6
Meter DHG: 1.61	K Factor: 140.47	Nozzle Diameter (in): 0.620	Start Time: 7:50
Pre-Test Pitot Leak Check: ✓	Post-Test Pitot Leak Check: ✓	Static Pressure ("H2O): 0	Stop Time: 1755
Pre-Test Pump Leak Check: 0.00 @ 16" Hg	Post-Test Pump Leak Check: 0.00 @ 15" Hg	Filter ID: 050113	Method: 5

Schematic of Stack:

209.63

Traverse Point	Sampling Time (minutes)	Vacuum ("Hg)	Velocity Head ("H2O)	Orifice Setting ("H2O)	Stack Temp. (oF)	Meter Volume (ft3) Initial Volume	Probe Temp (oF)	Filter Temp. (oF)	Meter Temp. Inlet (oF)	Meter Temp. Outlet (oF)	Condenser Temp. (oF)	XAD Temp. (oF)	Kr (ft3/min)	Pv (ft3)
						005.113								7.63
1-1	27.5	3	.0072	1.0	69	22.9	STACK	STACK	47	46	36			22.92
2	55.0	5	.012	1.7	71	45.9			54	48	37			45.88
3	82.5	4	.0081	1.1	72	64.8			56	50	38			64.77
4	110.0	6	.014	2.0	73	89.6			61	53	40			89.60
5	137.5	1	.003	.42	74	101.1			67	60	41			101.09
6	165.0	7	.016	2.3	76	127.6			72	67	42			127.63
7	192.5	9	.018	2.5	76	155.8			77	71	42			155.78
8	220.0	8	.016	2.3	78	182.3			82	75	43			182.32
9	247.5	3	.006	.84	78	198.6			88	81	44			198.57
10	275.0	3	.007	.98	81	216.1			88	85	44			216.13
11	302.5	4	.009	1.3	83	236.0			88	91	44			236.04
12	330.0	4	.008	1.1	82	254.8			89	90	45			254.81
2-1	357.5	6	.014	2.0	84	279.7			92	91	47			279.64
2	385.0	5	.012	1.7	84	302.63			91	90	47			302.63
3	412.5	5	.010	1.4	86	323.61			89	89	45			323.61
4	440.0	4	.007	.98	84	341.17			85	87	44			341.17
5	467.5	6	.013	1.8	84	365.1			84	85	42			365.09
6	495.0	9	.018	2.5	84	393.24			84	83	42			393.24
7	522.5	4	.009	1.3	82	413.15			82	81	42			413.15
8	550.0	5	.012	1.7	81	436.1			81	80	43			436.13
number	total	maximum	average root	average	average	difference	maximum	maximum	average		maximum	maximum	Reviewers Signature:	

Stack ID (inches): 552.24"

Upstream Disturbance (inches): 149"

Downstream Disturbance (inches): 2"

\# of points: 24

Moisture Determination

Imp. #	Tare	Final	Gain
1	412.2	511.4	
2	427.1	435.4	
3	298.8	421.7	
4	528.1	556.3	
	1666.2	1924.8	258.6

Notes:

C 2 of 2

Air Pollution Testing, Inc.: Isokinetic Sampling Datasheet

APT Job #:	DOC 5325	Date:	10/14/5	CO2 (%):	20.9	O2 (%):	0.0
Location:	Kiln outlet	Operator:	mc/DJ	Assumed Moisture (%):	1	Barometric Pressure (mbar):	864
Run #:	1 C	Probe ID:		Ambient Temperature (oF):		Probe Material:	SS
Meter Box Yd:	.992	Pitot Tube Coefficient:	.84	Probe Length (ft):	3'	Filter Temperature (oF):	Stack
Sample Box ID:	—	Meter Box ID:	MS-20	Probe Temperature (oF):	stack	Moisture (grams):	258.6
Meter DH@:	1.61	K Factor:	140.47	Nozzle Diameter (in):	.620	Start Time:	7:50
Pre-Test Pitot Leak Check:	✓	Post-Test Pitot Leak Check:	✓	Static Pressure ("H2O):	0.0	Stop Time:	1755
Pre-Test Pump Leak Check:	0.00 @ 15"Hg	Post-Test Pump Leak Check:	0.00 @ 15"Hg	Filter ID:	050113	Method:	5

Schematic of Stack:

20983

Traverse Point	Sampling Time (minutes)	Vacuum ("Hg)	Velocity Head ("H2O)	Orifice Setting ("H2O)	Stack Temp. (oF)	Meter Volume (ft3) Initial Volume	Probe Temp (oF)	Filter Temp. (oF)	Meter Temp. Inlet (oF)	Meter Temp. Outlet (oF)	Condenser Temp. (oF)	XAD Temp. (oF)	Ki (ft3/min)	Fv (ft3)
2-9	577.5	4	.008	1.1	81	454.90	Stack	Stack	81	80	42			454.90
10	605.0	3	.006	.84	79	471.207	↓	↓	81	80	43			471.15
11	632.5													
12	660.0													
28	665.0	9	.10095	1.49	79	466.094	86	86	77		47			
number	total	maximum	average root	average	average	difference	maximum	maximum	average		maximum	maximum		

Stack ID (inches): 552.24"

Upstream Disturbance (inches): 149"

Downstream Disturbance (inches): 2"

\# of points: 24

Moisture Determination

Imp. #	Tare	Final	Gain
1			
2			
3			
4			

Notes:

Reviewers Signature:

Appendix 3

Laboratory Data

Air Pollution Testing, Inc.
Gravimetric Laboratory Data Sheet
Analytical Balance A-160

POC 5325

Project Code:	POC 5325	Stack ID:	Kiln Outlet	**Date**	**Time**	**Tare**	**Date**	**Time**	**Final**	**Net**
Run #:	1A	Test Date:	10/14/2005	7-Sep-05	2:35 PM	0.3267	18-Oct-05	12:15 PM	0.3286	**0.00205**
Description:	Method 5 Filter			8-Sep-05	1:56 PM	0.3266	19-Oct-05	3:31 PM	0.3288	
APT Sample ID:	#050235									
Identification:				***avg tare mass (gm):***		0.32665	***avg final mass(gm):***		0.32870	
Project Code:	POC 5325	Stack ID:	Kiln Outlet	**Date**	**Time**	**Tare**	**Date**	**Time**	**Final**	**Net**
Run #:	1A	Test Date:	10/14/2005	4-Oct-05	2:44 PM	72.3715	18-Oct-05	12:20 PM	72.3741	**0.00270**
Description:	F 1/2 Acetone Rinse			8-Oct-05	2:43 PM	72.3712	19-Oct-05	3:35 PM	72.3740	
APT Sample ID:	Beaker B150-9221									
Identification:				***avg tare mass (gm):***		72.37135	***avg final mass(gm):***		72.37405	
Project Code:	POC 5325	Stack ID:	Kiln Outlet	**Date**	**Time**	**Tare**	**Date**	**Time**	**Final**	**Net**
Run #:	1B	Test Date:	10/14/2005	14-Jul-05	9:53 AM	0.3315	18-Oct-05	12:16 PM	0.3329	**0.00145**
Description:	Method 5 Filter			20-Jul-05	4:30 PM	0.3315	19-Oct-05	3:32 PM	0.3330	
APT Sample ID:	#050114									
Identification:				***avg tare mass (gm):***		0.33150	***avg final mass(gm):***		0.33295	
Project Code:	POC 5325	Stack ID:	Kiln Outlet	**Date**	**Time**	**Tare**	**Date**	**Time**	**Final**	**Net**
Run #:	1B	Test Date:	10/14/2005	16-Sep-05	3:45 PM	72.3217	18-Oct-05	12:21 PM	72.3242	**0.00240**
Description:	F 1/2 Acetone Rinse			8-Oct-05	1:08 PM	72.3219	19-Oct-05	3:36 PM	72.3242	
APT Sample ID:	Beaker B150-9133									
Identification:				***avg tare mass (gm):***		72.32180	***avg final mass(gm):***		72.32420	
Project Code:	POC 5325	Stack ID:	Kiln Outlet	**Date**	**Time**	**Tare**	**Date**	**Time**	**Final**	**Net**
Run #:	1C	Test Date:	10/14/2005	14-Jul-05	9:52 AM	0.3323	18-Oct-05	12:17 PM	0.3340	**0.00190**
Description:	Method 5 Filter			20-Jul-05	4:29 PM	0.3320	19-Oct-05	3:33 PM	0.3341	
APT Sample ID:	#050113									
Identification:				***avg tare mass (gm):***		0.33215	***avg final mass(gm):***		0.33405	
Project Code:	POC 5325	Stack ID:	Kiln Outlet	**Date**	**Time**	**Tare**	**Date**	**Time**	**Final**	**Net**
Run #:	1C	Test Date:	10/14/2005	16-Sep-05	10:03 AM	69.2180	18-Oct-05	12:22 PM	69.2219	**0.00365**
Description:	F 1/2 Acetone Rinse			8-Oct-05	1:07 PM	69.2184	19-Oct-05	3:37 PM	69.2218	
APT Sample ID:	Beaker B150-9151									
Identification:				***avg tare mass (gm):***		69.21820	***avg final mass(gm):***		69.22185	
Project Code:	POC 5325	Stack ID:	Kiln Outlet	**Date**	**Time**	**Tare**	**Date**	**Time**	**Final**	**Net**
Run #:	RB	Test Date:	10/14/2005	8-Oct-05	3:22 PM	70.6796	18-Oct-05	12:23 PM	70.6796	**0.00005**
Description:	Reagent Blank Acetone			9-Oct-05	2:26 PM	70.6795	19-Oct-05	3:38 PM	70.6796	
APT Sample ID:	Beaker B150-9259									
Identification:				***avg tare mass (gm):***		70.67955	***avg final mass(gm):***		70.67960	
Project Code:	POC 5325	Stack ID:	Kiln Outlet	**Date**	**Time**	**Tare**	**Date**	**Time**	**Final**	**Net**
Run #:	TB	Test Date:	10/14/2005	16-Sep-05	3:35 PM	71.1825	18-Oct-05	12:24 PM	71.1829	**0.00010**
Description:	F 1/2 Acetone Rinse			8-Oct-05	1:09 PM	71.1830	19-Oct-05	3:39 PM	71.1828	
APT Sample ID:	Beaker B150-9122									
Identification:				***avg tare mass (gm):***		71.18275	***avg final mass(gm):***		71.18285	

Chain of Custody / Sample Log

T: (303) 420 5949
F: (303) 420 5920

Air Pollution Testing, Inc.
5530 Marshall Street
Arvada, Colorado 80002

Project Code	POC 5325
Client	Great western Malting
Facility Name	Kiln Outlet
Project Manager	Mike Corrigan

Page 1 of 1

Relinquished By: Mike Corrigan Date: 10/17/05 Time: 15:00

Received By: Date: Time:

Sample ID	Run #	Filter/Beaker ID	Date/Time Collected	Matrix	Analysis	Special Instructions
Kiln Outlet Filter	1 A	050235	10/14/05	Filter	Grav.	To be Analized in drawer
Kiln Outlet Acetone	1 A	9221	10/14/05	Acetone	Grav.	"
Kiln outlet Filter	1 B	050114	10/14/05	Filter	Grav.	"
Kiln outlet Acetone	1 B	9133	10/14/05	Acetone	Grav.	"
Kiln outlet Filter	1 C	050113	10/14/05	Filter	Grav.	"
Kiln outlet Acetone	1 C	9151	10/14/05	Acetone	Grav.	"
Reagent Blank Acetone	50mL	9259	10/14/05	Acetone	Grav.	"
Train Blank		9122	10/14/05	Acetone	Grav.	"
Filter Blank			10/14/05	Filter	Grav.	"

Appendix 4

Calibration Information

A P T

AIR POLLUTION TESTING, INC.
THERMOCOUPLE AND DRY GAS METER CALIBRATION DATA

GAS METER ID :	M5-20 Pre-Test
DATE :	1-Jun-05
BARO. PRESS. (MBAR) :	870

GAS METER CALIBRATION

Run #1	DH	Vmet	Tin	Tout	Vref	Tref	DP	Vac	Time
Start	0.5	9.798	81	78	923.357	76	0.11	1	4:19 PM
Stop	0.5	15.320	83	79	928.850	77	0.11	1	4:31 PM
Avg.	**0.5**	**5.522**	**82**	**79**	**5.493**	**77**	**0.11**	**1**	**12.0**

Run #2	DH	Vmet	Tin	Tout	Vref	Tref	DP	Vac	Time
Start	1.5	15.320	84	80	928.850	77	.20	2	4:33 PM
Stop	1.5	20.895	86	80	934.378	77	0.2	2	4:40 PM
Avg.	**1.5**	**5.575**	**85**	**80**	**5.528**	**77**	**0.20**	**2**	**7.0**

Run #3	DH	Vmet	Tin	Tout	Vref	Tref	DP	Vac	Time
Start	3.0	28.628	87	81	942.111	77	0.32	1	4:42 PM
Stop	3.0	34.270	88	81	947.732	77	0.32	1	4:47 PM
Avg.	**3.0**	**5.642**	**88**	**81**	**5.621**	**77**	**0.32**	**1**	**5.0**

	Run #1	Run #2	Run #3	***Average***
Yref	0.9930	0.9930	0.9930	***0.993***
Yd	0.993	0.990	0.993	***0.992***
DH@	1.61	1.62	1.59	***1.61***

THERMOCOUPLE CALIBRATION

Calibration Temperature Reading (F)	Pyrometer Reading (F)	ABS (Relative Difference) % R
0	2	0.4
250	252	0.3
500	499	0.1
Max Absolute Difference %		0.4

PITOT LEAK CHECK

0.00 @ 3" H2O Positive
0.00 @ 3" H2O Negative

Technician: ag

A P T

AIR POLLUTION TESTING, INC.
THERMOCOUPLE AND DRY GAS METER CALIBRATION DATA

GAS METER ID :	M5-15
DATE :	3-Mar-04
BARO. PRESS. (MBAR) :	836

GAS METER CALIBRATION

Run #1	DH	Vmet	Tin	Tout	Vref	Tref	DP	Vac	Time
Start	0.5	1.372	59	59	446.147	61	0.38	2	9:20 AM
Stop	0.5	8.111	61	60	452.968	62	0.38	2	9:35 AM
Avg.	**0.5**	**6.739**	**60**	**60**	**6.821**	**62**	**0.38**	**2**	**15.0**

Run #2	DH	Vmet	Tin	Tout	Vref	Tref	DP	Vac	Time
Start	1.5	8.431	61	60	453.292	62	0.83	2	9:45 AM
Stop	1.5	15.787	65	62	460.758	62	0.85	2	9:55 AM
Avg.	**1.5**	**7.356**	**63**	**61**	**7.466**	**62**	**0.84**	**2**	**10.0**

Run #3	DH	Vmet	Tin	Tout	Vref	Tref	DP	Vac	Time
Start	3.0	16.154	65	62	461.132	62	1.60	2	9:56 AM
Stop	3.0	26.742	71	63	471.940	63	1.6	2	10:06 AM
Avg.	**3.0**	**10.588**	**68**	**63**	**10.808**	**63**	**1.60**	**2**	**10.0**

	Run #1	Run #2	Run #3	***Average***
Yref	0.989	0.989	0.989	***0.989***
Yd	0.995	0.997	1.001	***0.998***
DH@	1.67	1.86	1.77	***1.77***

THERMOCOUPLE CALIBRATION

Calibration Temperature Reading (F)	Pyrometer Reading (F)	ABS Difference) (Relative % R
100	99	0.2
500	496	0.4
1000	1000	0.0
Max Absolute Difference %		0.4

PITOT LEAK CHECK

0.00 @ 6" H2O Positive
0.00 @ 6" H2O Negative

Technician: SH

AIR POLLUTION TESTING, INC.
THERMOCOUPLE AND DRY GAS METER CALIBRATION DATA

GAS METER ID :	m5-15
DATE :	17-Oct-05
BARO. PRESS. (MBAR) :	878

GAS METER CALIBRATION

Run #1	DH	Vmet	Tin	Tout	Vref	Tref	DP	Vac	Time
Start	1.3	905.309	58	57	295.874	70	0.15	8	12:25 PM
Stop	1.3	911.467	67	59	302.243	71	0.15	8	12:34 PM
Avg.	**1.3**	**6.158**	**63**	**58**	**6.369**	**71**	**0.15**	**8**	**9.0**

Run #2	DH	Vmet	Tin	Tout	Vref	Tref	DP	Vac	Time
Start	1.3	911.467	65	58	302.243	71	0.15	8	12:35 PM
Stop	1.3	926.643	74	65	317.758	71	0.15	8	12:57 PM
Avg.	**1.3**	**15.176**	**70**	**62**	**15.515**	**71**	**0.15**	**8**	**22.0**

Run #3	DH	Vmet	Tin	Tout	Vref	Tref	DP	Vac	Time
Start	1.3	926.643	72	65	317.758	71	0.15	8	12:58 PM
Stop	1.3	930.104	75	66	321.295	71	0.15	8	1:03 PM
Avg.	**1.3**	**3.461**	**74**	**66**	**3.537**	**71**	**0.15**	**8**	**5.0**

	Run #1	Run #2	Run #3	***Average***
Yref	0.9930	0.9930	0.9930	***0.993***
Yd	1.003	1.001	1.008	***1.004***
DH@	1.76	1.76	1.74	***1.75***

THERMOCOUPLE CALIBRATION

Calibration Temperature Reading (F)	Pyrometer Reading (F)	ABS (Relative Difference) % R
25	22	0.6
100	96	0.7
250	249	0.1
Max Absolute Difference %		0.7

PITOT LEAK CHECK

0.00 @ 3" H2O Positive
0.00 @ 3" H2O Negative

Technician: mc

AIR POLLUTION TESTING, INC.
THERMOCOUPLE AND DRY GAS METER CALIBRATION DATA

GAS METER ID :	m5-20
DATE :	17-Oct-05
BARO. PRESS. (MBAR) :	877

GAS METER CALIBRATION

Run #1	DH	Vmet	Tin	Tout	Vref	Tref	DP	Vac	Time
Start	1.5	477.376	65	61	327.395	72	0.17	9	1:16 PM
Stop	1.5	481.487	69	62	331.526	72	0.17	9	1:21 PM
Avg.	**1.5**	**4.111**	**67**	**62**	**4.131**	**72**	**0.17**	**9**	**5.0**

Run #2	DH	Vmet	Tin	Tout	Vref	Tref	DP	Vac	Time
Start	1.5	481.487	69	63	331.526	72	0.17	9	1:22 PM
Stop	1.5	491.994	74	66	342.270	72	0.17	9	1:35 PM
Avg.	**1.5**	**10.507**	**72**	**65**	**10.744**	**72**	**0.17**	**9**	**13.0**

Run #3	DH	Vmet	Tin	Tout	Vref	Tref	DP	Vac	Time
Start	1.5	491.994	74	66	342.270	72	0.17	9	1:36 PM
Stop	1.5	498.520	74	68	348.878	72	0.17	9	1:44 PM
Avg.	**1.5**	**6.526**	**74**	**67**	**6.608**	**72**	**0.17**	**9**	**8.0**

	Run #1	Run #2	Run #3	***Average***
Yref	0.9930	0.9930	0.9930	***0.993***
Yd	0.979	1.003	0.998	***0.993***
DH@	1.49	1.48	1.47	***1.48***

THERMOCOUPLE CALIBRATION

Calibration Temperature Reading (F)	Pyrometer Reading (F)	ABS (Relative Difference) % R
25	22	0.6
100	96	0.7
250	248	0.3
Max Absolute Difference %		0.7

PITOT LEAK CHECK

0.00 @ 3" H2O Positive
0.00 @ 3" H2O Negative

Technician: nl

AIR POLLUTION TESTING, INC.
THERMOCOUPLE AND DRY GAS METER CALIBRATION DATA

GAS METER ID :	m5-1
DATE :	17-Oct-05
BARO. PRESS. (MBAR) :	876

GAS METER CALIBRATION

Run #1	DH	Vmet	Tin	Tout	Vref	Tref	DP	Vac	Time
Start	1.3	722.095	76	72	359.279	74	0.17	9	2:10 PM
Stop	1.3	734.477	82	76	372.087	74	0.17	9	2:28 PM
Avg.	**1.3**	**12.382**	**79**	**74**	**12.808**	**74**	**0.17**	**9**	**18.0**

Run #2	DH	Vmet	Tin	Tout	Vref	Tref	DP	Vac	Time
Start	1.3	734.477	81	76	372.087	74	0.17	9	2:30 PM
Stop	1.3	753.842	87	81	391.985	75	0.17	9	2:58 PM
Avg.	**1.3**	**19.365**	**84**	**79**	**19.898**	**75**	**0.17**	**9**	**28.0**

Run #3	DH	Vmet	Tin	Tout	Vref	Tref	DP	Vac	Time
Start	1.3	753.842	85	81	391.985	75	0.17	9	3:00 PM
Stop	1.3	757.317	87	82	395.528	75	0.17	9	3:05 PM
Avg.	**1.3**	**3.475**	**86**	**82**	**3.543**	**75**	**0.17**	**9**	**5.0**

	Run #1	Run #2	Run #3	***Average***
Yref	0.9930	0.9930	0.9930	***0.993***
Yd	1.028	1.029	1.025	***1.027***
DH@	1.71	1.71	1.71	***1.71***

THERMOCOUPLE CALIBRATION

Calibration Temperature Reading (F)	Pyrometer Reading (F)	ABS (Relative Difference) % R
25	30	1.0
100	104	0.7
250	257	1.0
Max Absolute Difference %		1.0

PITOT LEAK CHECK

0.00 @ 3" H2O Positive
0.00 @ 3" H2O Negative

Technician: mc

Bulletin H-17-A

Dwyer®

Series 471 Digital Thermo Anemometer

Specifications – Installation and Operating Instructions

Introduction

The Series 471 Digital Thermo Anemometers are versatile dual function hand-held battery operated instruments that quickly and easily measure air velocity in four field selectable ranges - feet per minute (FPM) or meters per second (MPS) - plus air temperature in °F or °C. High contrast LCD display shows both range selected and present velocity.

The stainless steel probe (5/16" dia.) with comfortable hand grip is etched with insertion depth marks from 0-8 inches and 0-20 cm on the Model 471-1.

The Model 471-2 and 471-3 probes extend to 33 inches (83cm). The probe tip on the Model 471-3 is bendable up to 90 degrees in any direction for easy access in hard-to-reach locations. A 7/16" (111 mm) hole is required for full probe insertion. When extending or collapsing the tip, be sure the connecting cable moves freely through the opening at the base of the handle. For optimum accuracy, be sure to extend the tip a minimum of 2½" (6.36 cm) for all measurements.

Also note that with all models the two openings in the tip must be parallel to air flow for best accuracy. A convenient way to assure proper alignment when tip is out of view (such as inside a duct) is to note the orientation relative to the handle before insertion.

Battery Installation

To install the 9 volt alkaline battery, first remove the two screws and end cap at the bottom of unit. Attach the battery clip to the battery and place it inside the case. Be careful not to pinch wires when putting battery in place. Replace cover and sealing gasket. If wrist strap will be used, install "Z" shaped clip under one of the screw heads before securing. Do not overtighten screws. Snap wrist strap to the clip.

PHYSICAL DATA

Specified Accuracy Temperature Limits: 59 to 86°F (15-30°C). Outside this range add 0.11% per °F (0.2% per °C).
Flow Temperature Range: 32-200°F, 0-100°C.

TEMPERATURE MEASUREMENT: 0 to 200°F, -17 to 100°C
Temperature Accuracy: ±2°F, 1°C.
Resolution: 0.1°
Ambient Temperature Limits: 32 to 104°F, 0-40°C.
Storage Temperature Limits: -40 to 176°F, -40 to 80°C.
Probe: 5/16" [8.13 mm] diameter probe with integral hand grip and 6 ft. [15.2 cm] coiled cord.
Length of probe: Model 471-1=10" [25.4 cm]; Models 471-2 and 471-3= 33" [83 cm].
Power Source: 9 volt alkaline battery, included.
Housing Size: 6 9/16"H x 2 13/16"W x 29/32"D (166 x 71 x 23 mm).
Weight, Battery Included: 12 ounces (340 grams).
Carrying Case: 2⅜"H x 13½"W x 10½"D (60 x 343 x 267 mm).

Air Velocity Ranges

Range Number	Velocity, FPM	Velocity, MPS	Accuracy*
1	0-500	0-3.0	±3% F.S.
2	0-1500	0-7.0	±3% F.S.
3	0-5000	0-30	±4% F.S.
4	0-15000	0-70	±5% F.S.

*Temperature Range for velocity accuracy specified is 59 to 86°F (15 to 30°C). Outside this range add 0.11% per °F (0.2% per °C).

On-Off Operation

The on-off control is a toggle function. Press the ON/OFF key once to turn unit on and again to turn it off. If the Series 471 is left on for approximately 2½ minutes with no activity, the device will turn off automatically to conserve battery life.

Display Backlight

The Series 471 includes a standard backlight display to improve visibility under poor lighting conditions. The instrument must first be switched off before this feature can be activated. Next, press and hold the ON/OFF key down. After about 1 second, the backlight will switch on and remain lighted for approximately 2 minutes. It will then automatically shut off to conserve battery life.

Selecting Velocity or Temperature Measurement

To switch between velocity and temperature measurement, press the VELOCITY/TEMP key.

Specifications – Installation and Operating Instructions

Selecting Units of Measurement
The Series 471 will display velocity or temperature in either English or metric units. Velocity can be expressed in your choice of feet per minute (FPM) or meters per second (MPS). Temperature can be indicated in either °F or °C. Currently selected units will be indicated on the display. To change units press the UNITS key. Units selected will remain in memory even when power is shut off.

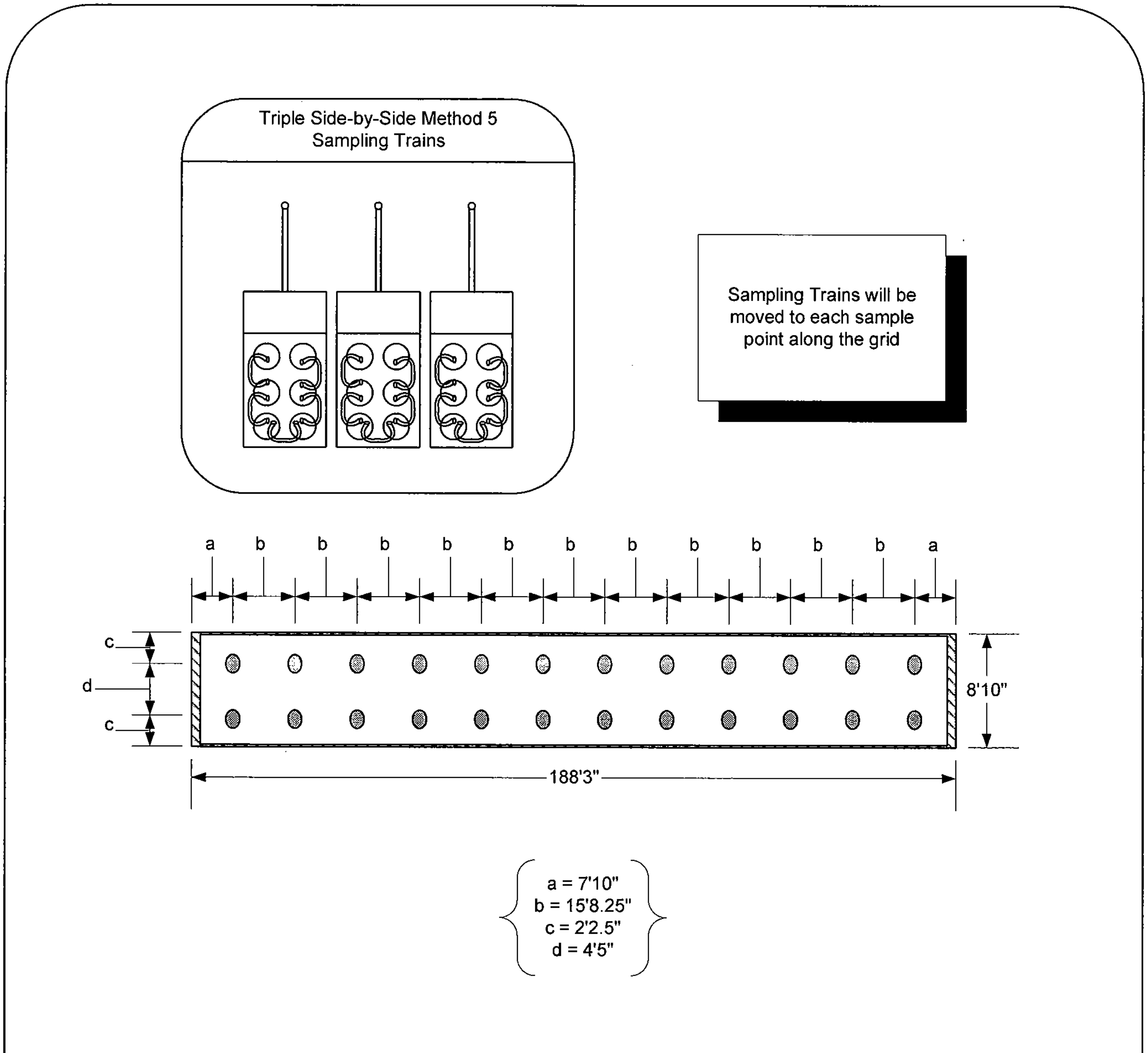
Selecting Velocity Range
Four velocity ranges can be selected in either English or metric units. Choose a range where typical readings fall within the center to upper portion of the span. The range selected will be shown in smaller characters in the lower left corner of the display. To change ranges, press the RANGE key until the required one is shown. Each time the range is changed, the display velocity will momentarily read zero until the sensor stabilizes with the new range.

Low Battery Indicator
A weak battery can cause improper operation and/or inaccurate measurements. A low battery indicator is included on the display to warn when the battery needs to be replaced. Although the unit might appear to operate and indicate properly, accuracy of readings cannot be assured when the LO BAT indicator is displayed. Replace the exhausted battery with a fresh alkaline type such as Duracell® MN1604, Eveready® 522 or equivalent. Zinc carbon types are not recommended because of their significantly shorter life and increased potential for leakage. Do not leave exhausted batteries in the unit due to possible leakage and resulting damage.

Probe Care and Cleaning
Always cover the tip when not in use by fully collapsing the telescoping sections or sliding up the cover attached to the 471-1. Use only clean, dry particulate free air. Although probe requires little maintenance, occasional cleaning may be necessary for best accuracy.
Caution: Tip is fragile and must not be touched. Do not use brushes, cotton swabs, etc. to clean. Remove battery before cleaning. Provide adequate ventilation and gently bathe the probe tip in a small container of denatured alcohol. Wash briefly, avoiding extended soaking. Remove from bath and gently shake off excess. Allow to completely air dry before replacing battery and returning to service. Do not use pressurized cleaners or compressed air, both of which could cause permanent damage.

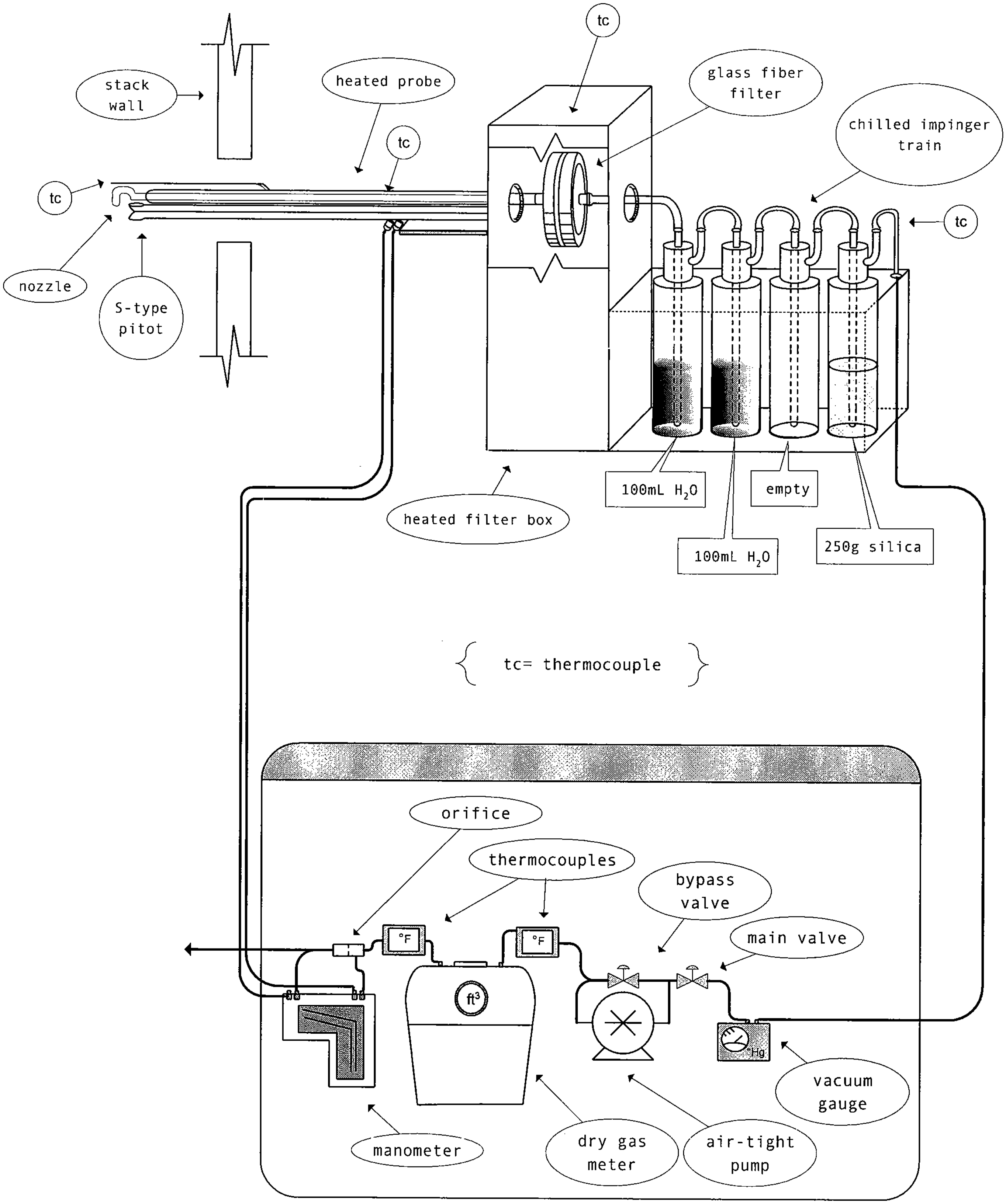
Appendix 5

Schematics



Kiln Vent Sampling Layout with Sampling Points (●)

Kiln Vent Sampling Schematic
Great Western Malting
(not to scale)



EPA Method 5
sampling train schematic

E-5 EPA AP-42 Section 1.4

1.4 Natural Gas Combustion

1.4.1 General[1-2]

Natural gas is one of the major combustion fuels used throughout the country. It is mainly used to generate industrial and utility electric power, produce industrial process steam and heat, and heat residential and commercial space. Natural gas consists of a high percentage of methane (generally above 85 percent) and varying amounts of ethane, propane, butane, and inerts (typically nitrogen, carbon dioxide, and helium). The average gross heating value of natural gas is approximately 1,020 British thermal units per standard cubic foot (Btu/scf), usually varying from 950 to 1,050 Btu/scf.

1.4.2 Firing Practices[3-5]

There are three major types of boilers used for natural gas combustion in commercial, industrial, and utility applications: watertube, firetube, and cast iron. Watertube boilers are designed to pass water through the inside of heat transfer tubes while the outside of the tubes is heated by direct contact with the hot combustion gases and through radiant heat transfer. The watertube design is the most common in utility and large industrial boilers. Watertube boilers are used for a variety of applications, ranging from providing large amounts of process steam, to providing hot water or steam for space heating, to generating high-temperature, high-pressure steam for producing electricity. Furthermore, watertube boilers can be distinguished either as field erected units or packaged units.

Field erected boilers are boilers that are constructed on site and comprise the larger sized watertube boilers. Generally, boilers with heat input levels greater than 100 MMBtu/hr, are field erected. Field erected units usually have multiple burners and, given the customized nature of their construction, also have greater operational flexibility and NO_x control options. Field erected units can also be further categorized as wall-fired or tangential-fired. Wall-fired units are characterized by multiple individual burners located on a single wall or on opposing walls of the furnace while tangential units have several rows of air and fuel nozzles located in each of the four corners of the boiler.

Package units are constructed off-site and shipped to the location where they are needed. While the heat input levels of packaged units may range up to 250 MMBtu/hr, the physical size of these units are constrained by shipping considerations and generally have heat input levels less than 100 MMBtu/hr. Packaged units are always wall-fired units with one or more individual burners. Given the size limitations imposed on packaged boilers, they have limited operational flexibility and cannot feasibly incorporate some NO_x control options.

Firetube boilers are designed such that the hot combustion gases flow through tubes, which heat the water circulating outside of the tubes. These boilers are used primarily for space heating systems, industrial process steam, and portable power boilers. Firetube boilers are almost exclusively packaged units. The two major types of firetube units are Scotch Marine boilers and the older firebox boilers. In cast iron boilers, as in firetube boilers, the hot gases are contained inside the tubes and the water being heated circulates outside the tubes. However, the units are constructed of cast iron rather than steel. Virtually all cast iron boilers are constructed as package boilers. These boilers are used to produce either low-pressure steam or hot water, and are most commonly used in small commercial applications.

Natural gas is also combusted in residential boilers and furnaces. Residential boilers and furnaces generally resemble firetube boilers with flue gas traveling through several channels or tubes with water or air circulated outside the channels or tubes.

1.4.3 Emissions[3-4]

The emissions from natural gas-fired boilers and furnaces include nitrogen oxides (NO_x), carbon monoxide (CO), and carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), volatile organic compounds (VOCs), trace amounts of sulfur dioxide (SO_2), and particulate matter (PM).

Nitrogen Oxides -

Nitrogen oxides formation occurs by three fundamentally different mechanisms. The principal mechanism of NO_x formation in natural gas combustion is thermal NO_x. The thermal NO_x mechanism occurs through the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules in the combustion air. Most NO_x formed through the thermal NO_x mechanism occurs in the high temperature flame zone near the burners. The formation of thermal NO_x is affected by three furnace-zone factors: (1) oxygen concentration, (2) peak temperature, and (3) time of exposure at peak temperature. As these three factors increase, NO_x emission levels increase. The emission trends due to changes in these factors are fairly consistent for all types of natural gas-fired boilers and furnaces. Emission levels vary considerably with the type and size of combustor and with operating conditions (e.g., combustion air temperature, volumetric heat release rate, load, and excess oxygen level).

The second mechanism of NO_x formation, called prompt NO_x, occurs through early reactions of nitrogen molecules in the combustion air and hydrocarbon radicals from the fuel. Prompt NO_x reactions occur within the flame and are usually negligible when compared to the amount of NO_x formed through the thermal NO_x mechanism. However, prompt NO_x levels may become significant with ultra-low-NO_x burners.

The third mechanism of NO_x formation, called fuel NO_x, stems from the evolution and reaction of fuel-bound nitrogen compounds with oxygen. Due to the characteristically low fuel nitrogen content of natural gas, NO_x formation through the fuel NO_x mechanism is insignificant.

Carbon Monoxide -

The rate of CO emissions from boilers depends on the efficiency of natural gas combustion. Improperly tuned boilers and boilers operating at off-design levels decrease combustion efficiency resulting in increased CO emissions. In some cases, the addition of NO_x control systems such as low NO_x burners and flue gas recirculation (FGR) may also reduce combustion efficiency, resulting in higher CO emissions relative to uncontrolled boilers.

Volatile Organic Compounds -

The rate of VOC emissions from boilers and furnaces also depends on combustion efficiency. VOC emissions are minimized by combustion practices that promote high combustion temperatures, long residence times at those temperatures, and turbulent mixing of fuel and combustion air. Trace amounts of VOC species in the natural gas fuel (e.g., formaldehyde and benzene) may also contribute to VOC emissions if they are not completely combusted in the boiler.

Sulfur Oxides -

Emissions of SO_2 from natural gas-fired boilers are low because pipeline quality natural gas typically has sulfur levels of 2,000 grains per million cubic feet. However, sulfur-containing odorants are added to natural gas for detecting leaks, leading to small amounts of SO_2 emissions. Boilers combusting unprocessed natural gas may have higher SO_2 emissions due to higher levels of sulfur in the natural gas. For these units, a sulfur mass balance should be used to determine SO_2 emissions.

Particulate Matter -

Because natural gas is a gaseous fuel, filterable PM emissions are typically low. Particulate matter from natural gas combustion has been estimated to be less than 1 micrometer in size and has filterable and condensable fractions. Particulate matter in natural gas combustion are usually larger molecular weight hydrocarbons that are not fully combusted. Increased PM emissions may result from poor air/fuel mixing or maintenance problems.

Greenhouse Gases -[6-9]

CO_2, CH_4, and N_2O emissions are all produced during natural gas combustion. In properly tuned boilers, nearly all of the fuel carbon (99.9 percent) in natural gas is converted to CO_2 during the combustion process. This conversion is relatively independent of boiler or combustor type. Fuel carbon not converted to CO_2 results in CH_4, CO, and/or VOC emissions and is due to incomplete combustion. Even in boilers operating with poor combustion efficiency, the amount of CH_4, CO, and VOC produced is insignificant compared to CO_2 levels.

Formation of N_2O during the combustion process is affected by two furnace-zone factors. N_2O emissions are minimized when combustion temperatures are kept high (above 1475°F) and excess oxygen is kept to a minimum (less than 1 percent).

Methane emissions are highest during low-temperature combustion or incomplete combustion, such as the start-up or shut-down cycle for boilers. Typically, conditions that favor formation of N_2O also favor emissions of methane.

1.4.4 Controls[4,10]

NO_x Controls -

Currently, the two most prevalent combustion control techniques used to reduce NO_x emissions from natural gas-fired boilers are flue gas recirculation (FGR) and low NO_x burners. In an FGR system, a portion of the flue gas is recycled from the stack to the burner windbox. Upon entering the windbox, the recirculated gas is mixed with combustion air prior to being fed to the burner. The recycled flue gas consists of combustion products which act as inerts during combustion of the fuel/air mixture. The FGR system reduces NO_x emissions by two mechanisms. Primarily, the recirculated gas acts as a dilutent to reduce combustion temperatures, thus suppressing the thermal NO_x mechanism. To a lesser extent, FGR also reduces NO_x formation by lowering the oxygen concentration in the primary flame zone. The amount of recirculated flue gas is a key operating parameter influencing NO_x emission rates for these systems. An FGR system is normally used in combination with specially designed low NO_x burners capable of sustaining a stable flame with the increased inert gas flow resulting from the use of FGR. When low NO_x burners and FGR are used in combination, these techniques are capable of reducing NO_x emissions by 60 to 90 percent.

Low NO_x burners reduce NO_x by accomplishing the combustion process in stages. Staging partially delays the combustion process, resulting in a cooler flame which suppresses thermal NO_x formation. The two most common types of low NO_x burners being applied to natural gas-fired boilers are staged air burners and staged fuel burners. NO_x emission reductions of 40 to 85 percent (relative to uncontrolled emission levels) have been observed with low NO_x burners.

Other combustion control techniques used to reduce NO_x emissions include staged combustion and gas reburning. In staged combustion (e.g., burners-out-of-service and overfire air), the degree of staging is a key operating parameter influencing NO_x emission rates. Gas reburning is similar to the use of overfire in the use of combustion staging. However, gas reburning injects additional amounts of natural gas in the upper furnace, just before the overfire air ports, to provide increased reduction of NO_x to NO_2.

Two postcombustion technologies that may be applied to natural gas-fired boilers to reduce NO_x emissions are selective noncatalytic reduction (SNCR) and selective catalytic reduction (SCR). The SNCR system injects ammonia (NH_3) or urea into combustion flue gases (in a specific temperature zone) to reduce NO_x emission. The Alternative Control Techniques (ACT) document for NO_x emissions from utility boilers, maximum SNCR performance was estimated to range from 25 to 40 percent for natural gas-fired boilers.[12] Performance data available from several natural gas fired utility boilers with SNCR show a 24 percent reduction in NO_x for applications on wall-fired boilers and a 13 percent reduction in NO_x for applications on tangential-fired boilers.[11] In many situations, a boiler may have an SNCR system installed to trim NO_x emissions to meet permitted levels. In these cases, the SNCR system may not be operated to achieve maximum NO_x reduction. The SCR system involves injecting NH_3 into the flue gas in the presence of a catalyst to reduce NO_x emissions. No data were available on SCR performance on natural gas fired boilers at the time of this publication. However, the ACT Document for utility boilers estimates NO_x reduction efficiencies for SCR control ranging from 80 to 90 percent.[12]

Emission factors for natural gas combustion in boilers and furnaces are presented in Tables 1.4-1, 1.4-2, 1.4-3, and 1.4-4.[11] Tables in this section present emission factors on a volume basis (lb/10^6 scf). To convert to an energy basis (lb/MMBtu), divide by a heating value of 1,020 MMBtu/10^6 scf. For the purposes of developing emission factors, natural gas combustors have been organized into three general categories: large wall-fired boilers with greater than 100 MMBtu/hr of heat input, boilers and residential furnaces with less than 100 MMBtu/hr of heat input, and tangential-fired boilers. Boilers within these categories share the same general design and operating characteristics and hence have similar emission characteristics when combusting natural gas.

Emission factors are rated from A to E to provide the user with an indication of how "good" the factor is, with "A" being excellent and "E" being poor. The criteria that are used to determine a rating for an emission factor can be found in the Emission Factor Documentation for AP-42 Section 1.4 and in the introduction to the AP-42 document.

1.4.5 Updates Since the Fifth Edition

The Fifth Edition was released in January 1995. Revisions to this section are summarized below. For further detail, consult the Emission Factor Documentation for this section. These and other documents can be found on the Emission Factor and Inventory Group (EFIG) home page (http://www.epa.gov/ttn/chief).

Supplement D, March 1998

- Text was revised concerning Firing Practices, Emissions, and Controls.
- All emission factors were updated based on 482 data points taken from 151 source tests. Many new emission factors have been added for speciated organic compounds, including hazardous air pollutants.

July 1998 - minor changes

- Footnote D was added to table 1.4-3 to explain why the sum of individual HAP may exceed VOC or TOC, the web address was updated, and the references were reordered.

Table 1.4-1. EMISSION FACTORS FOR NITROGEN OXIDES (NO_x) AND CARBON MONOXIDE (CO) FROM NATURAL GAS COMBUSTION[a]

Combustor Type (MMBtu/hr Heat Input) [SCC]	NO_x[b]		CO	
	Emission Factor (lb/10^6 scf)	Emission Factor Rating	Emission Factor (lb/10^6 scf)	Emission Factor Rating
Large Wall-Fired Boilers (>100) [1-01-006-01, 1-02-006-01, 1-03-006-01]				
Uncontrolled (Pre-NSPS)[c]	280	A	84	B
Uncontrolled (Post-NSPS)[c]	190	A	84	B
Controlled - Low NO_x burners	140	A	84	B
Controlled - Flue gas recirculation	100	D	84	B
Small Boilers (<100) [1-01-006-02, 1-02-006-02, 1-03-006-02, 1-03-006-03]				
Uncontrolled	100	B	84	B
Controlled - Low NO_x burners	50	D	84	B
Controlled - Low NO_x burners/Flue gas recirculation	32	C	84	B
Tangential-Fired Boilers (All Sizes) [1-01-006-04]				
Uncontrolled	170	A	24	C
Controlled - Flue gas recirculation	76	D	98	D
Residential Furnaces (<0.3) [No SCC]				
Uncontrolled	94	B	40	B

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. To convert from lb/10^6 scf to kg/10^6 m^3, multiply by 16. Emission factors are based on an average natural gas higher heating value of 1,020 Btu/scf. To convert from 1b/10^6 scf to lb/MMBtu, divide by 1,020. The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value. SCC = Source Classification Code. ND = no data. NA = not applicable.

[b] Expressed as NO_2. For large and small wall fired boilers with SNCR control, apply a 24 percent reduction to the appropriate NO_X emission factor. For tangential-fired boilers with SNCR control, apply a 13 percent reduction to the appropriate NO_X emission factor.

[c] NSPS=New Source Performance Standard as defined in 40 CFR 60 Subparts D and Db. Post-NSPS units are boilers with greater than 250 MMBtu/hr of heat input that commenced construction modification, or reconstruction after August 17, 1971, and units with heat input capacities between 100 and 250 MMBtu/hr that commenced construction modification, or reconstruction after June 19, 1984.

TABLE 1.4-2. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM NATURAL GAS COMBUSTION[a]

Pollutant	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
CO_2[b]	120,000	A
Lead	0.0005	D
N_2O (Uncontrolled)	2.2	E
N_2O (Controlled-low-NO_X burner)	0.64	E
PM (Total)[c]	7.6	D
PM (Condensable)[c]	5.7	D
PM (Filterable)[c]	1.9	B
SO_2[d]	0.6	A
TOC	11	B
Methane	2.3	B
VOC	5.5	C

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. Data are for all natural gas combustion sources. To convert from $lb/10^6$ scf to $kg/10^6$ m^3, multiply by 16. To convert from $lb/10^6$ scf to 1b/MMBtu, divide by 1,020. The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value. TOC = Total Organic Compounds. VOC = Volatile Organic Compounds.

[b] Based on approximately 100% conversion of fuel carbon to CO_2. $CO_2[lb/10^6$ scf$]$ = (3.67) (CON) (C)(D), where CON = fractional conversion of fuel carbon to CO_2, C = carbon content of fuel by weight (0.76), and D = density of fuel, $4.2x10^4$ $lb/10^6$ scf.

[c] All PM (total, condensible, and filterable) is assumed to be less than 1.0 micrometer in diameter. Therefore, the PM emission factors presented here may be used to estimate PM_{10}, $PM_{2.5}$ or PM_1 emissions. Total PM is the sum of the filterable PM and condensible PM. Condensible PM is the particulate matter collected using EPA Method 202 (or equivalent). Filterable PM is the particulate matter collected on, or prior to, the filter of an EPA Method 5 (or equivalent) sampling train.

[d] Based on 100% conversion of fuel sulfur to SO_2.
Assumes sulfur content is natural gas of 2,000 grains/10^6 scf. The SO_2 emission factor in this table can be converted to other natural gas sulfur contents by multiplying the SO_2 emission factor by the ratio of the site-specific sulfur content (grains/10^6 scf) to 2,000 grains/10^6 scf.

TABLE 1.4-3. EMISSION FACTORS FOR SPECIATED ORGANIC COMPOUNDS FROM NATURAL GAS COMBUSTION[a]

CAS No.	Pollutant	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
91-57-6	2-Methylnaphthalene[b, c]	2.4E-05	D
56-49-5	3-Methylchloranthrene[b, c]	<1.8E-06	E
	7,12-Dimethylbenz(a)anthracene[b,c]	<1.6E-05	E
83-32-9	Acenaphthene[b,c]	<1.8E-06	E
203-96-8	Acenaphthylene[b,c]	<1.8E-06	E
120-12-7	Anthracene[b,c]	<2.4E-06	E
56-55-3	Benz(a)anthracene[b,c]	<1.8E-06	E
71-43-2	Benzene[b]	2.1E-03	B
50-32-8	Benzo(a)pyrene[b,c]	<1.2E-06	E
205-99-2	Benzo(b)fluoranthene[b,c]	<1.8E-06	E
191-24-2	Benzo(g,h,i)perylene[b,c]	<1.2E-06	E
205-82-3	Benzo(k)fluoranthene[b,c]	<1.8E-06	E
106-97-8	Butane	2.1E+00	E
218-01-9	Chrysene[b,c]	<1.8E-06	E
53-70-3	Dibenzo(a,h)anthracene[b,c]	<1.2E-06	E
25321-22-6	Dichlorobenzene[b]	1.2E-03	E
74-84-0	Ethane	3.1E+00	E
206-44-0	Fluoranthene[b,c]	3.0E-06	E
86-73-7	Fluorene[b,c]	2.8E-06	E
50-00-0	Formaldehyde[b]	7.5E-02	B
110-54-3	Hexane[b]	1.8E+00	E
193-39-5	Indeno(1,2,3-cd)pyrene[b,c]	<1.8E-06	E
91-20-3	Naphthalene[b]	6.1E-04	E
109-66-0	Pentane	2.6E+00	E
85-01-8	Phenanathrene[b,c]	1.7E-05	D

TABLE 1.4-3. EMISSION FACTORS FOR SPECIATED ORGANIC COMPOUNDS FROM NATURAL GAS COMBUSTION (Continued)

CAS No.	Pollutant	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
74-98-6	Propane	1.6E+00	E
129-00-0	Pyrene[b, c]	5.0E-06	E
108-88-3	Toluene[b]	3.4E-03	C

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. Data are for all natural gas combustion sources. To convert from $lb/10^6$ scf to $kg/10^6$ m^3, multiply by 16. To convert from $1b/10^6$ scf to lb/MMBtu, divide by 1,020. Emission Factors preceeded with a less-than symbol are based on method detection limits.
[b] Hazardous Air Pollutant (HAP) as defined by Section 112(b) of the Clean Air Act.
[c] HAP because it is Polycyclic Organic Matter (POM). POM is a HAP as defined by Section 112(b) of the Clean Air Act.
[d] The sum of individual organic compounds may exceed the VOC and TOC emission factors due to differences in test methods and the availability of test data for each pollutant.

TABLE 1.4-4. EMISSION FACTORS FOR METALS FROM NATURAL GAS COMBUSTION[a]

CAS No.	Pollutant	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
7440-38-2	Arsenic[b]	2.0E-04	E
7440-39-3	Barium	4.4E-03	D
7440-41-7	Beryllium[b]	<1.2E-05	E
7440-43-9	Cadmium[b]	1.1E-03	D
7440-47-3	Chromium[b]	1.4E-03	D
7440-48-4	Cobalt[b]	8.4E-05	D
7440-50-8	Copper	8.5E-04	C
7439-96-5	Manganese[b]	3.8E-04	D
7439-97-6	Mercury[b]	2.6E-04	D
7439-98-7	Molybdenum	1.1E-03	D
7440-02-0	Nickel[b]	2.1E-03	C
7782-49-2	Selenium[b]	<2.4E-05	E
7440-62-2	Vanadium	2.3E-03	D
7440-66-6	Zinc	2.9E-02	E

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. Data are for all natural gas combustion sources. Emission factors preceeded by a less-than symbol are based on method detection limits. To convert from $lb/10^6$ scf to $kg/10^6\ m^3$, multiply by l6. To convert from $lb/10^6$ scf to 1b/MMBtu, divide by 1,020.

[b] Hazardous Air Pollutant as defined by Section 112(b) of the Clean Air Act.

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E-6 EPA AP-42 Section 3.3

3.3 Gasoline And Diesel Industrial Engines

3.3.1 General

The engine category addressed by this section covers a wide variety of industrial applications of both gasoline and diesel internal combustion (IC) engines such as aerial lifts, fork lifts, mobile refrigeration units, generators, pumps, industrial sweepers/scrubbers, material handling equipment (such as conveyors), and portable well-drilling equipment. The three primary fuels for reciprocating IC engines are gasoline, diesel fuel oil (No.2), and natural gas. Gasoline is used primarily for mobile and portable engines. Diesel fuel oil is the most versatile fuel and is used in IC engines of all sizes. The rated power of these engines covers a rather substantial range, up to 250 horsepower (hp) for gasoline engines and up to 600 hp for diesel engines. (Diesel engines greater than 600 hp are covered in Section 3.4, "Large Stationary Diesel And All Stationary Dual-fuel Engines".) Understandably, substantial differences in engine duty cycles exist. It was necessary, therefore, to make reasonable assumptions concerning usage in order to formulate some of the emission factors.

3.3.2 Process Description

All reciprocating IC engines operate by the same basic process. A combustible mixture is first compressed in a small volume between the head of a piston and its surrounding cylinder. The mixture is then ignited, and the resulting high-pressure products of combustion push the piston through the cylinder. This movement is converted from linear to rotary motion by a crankshaft. The piston returns, pushing out exhaust gases, and the cycle is repeated.

There are 2 methods used for stationary reciprocating IC engines: compression ignition (CI) and spark ignition (SI). This section deals with both types of reciprocating IC engines. All diesel-fueled engines are compression ignited, and all gasoline-fueled engines are spark ignited.

In CI engines, combustion air is first compression heated in the cylinder, and diesel fuel oil is then injected into the hot air. Ignition is spontaneous because the air temperature is above the autoignition temperature of the fuel. SI engines initiate combustion by the spark of an electrical discharge. Usually the fuel is mixed with the air in a carburetor (for gasoline) or at the intake valve (for natural gas), but occasionally the fuel is injected into the compressed air in the cylinder.

CI engines usually operate at a higher compression ratio (ratio of cylinder volume when the piston is at the bottom of its stroke to the volume when it is at the top) than SI engines because fuel is not present during compression; hence there is no danger of premature autoignition. Since engine thermal efficiency rises with increasing pressure ratio (and pressure ratio varies directly with compression ratio), CI engines are more efficient than SI engines. This increased efficiency is gained at the expense of poorer response to load changes and a heavier structure to withstand the higher pressures.[1]

3.3.3 Emissions

Most of the pollutants from IC engines are emitted through the exhaust. However, some total organic compounds (TOC) escape from the crankcase as a result of blowby (gases that are vented from the oil pan after they have escaped from the cylinder past the piston rings) and from the fuel tank and carburetor because of evaporation. Nearly all of the TOCs from diesel CI engines enter the atmosphere from the exhaust. Evaporative losses are insignificant in diesel engines due to the low volatility of diesel fuels.

The primary pollutants from internal combustion engines are oxides of nitrogen (NO_x), total organic compounds (TOC), carbon monoxide (CO), and particulates, which include both visible (smoke) and nonvisible emissions. Nitrogen oxide formation is directly related to high pressures and temperatures during the combustion process and to the nitrogen content, if any, of the fuel. The other pollutants, HC, CO, and smoke, are primarily the result of incomplete combustion. Ash and metallic additives in the fuel also contribute to the particulate content of the exhaust. Sulfur oxides (SO_x) also appear in the exhaust from IC engines. The sulfur compounds, mainly sulfur dioxide (SO_2), are directly related to the sulfur content of the fuel.[2]

3.3.3.1 Nitrogen Oxides -

Nitrogen oxide formation occurs by two fundamentally different mechanisms. The predominant mechanism with internal combustion engines is thermal NO_x which arises from the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules in the combustion air. Most thermal NO_x is formed in the high-temperature region of the flame from dissociated molecular nitrogen in the combustion air. Some NO_x, called prompt NO_x, is formed in the early part of the flame from reaction of nitrogen intermediary species, and HC radicals in the flame. The second mechanism, fuel NO_x, stems from the evolution and reaction of fuel-bound nitrogen compounds with oxygen. Gasoline, and most distillate oils have no chemically-bound fuel N_2 and essentially all NO_x formed is thermal NO_x.

3.3.3.2 Total Organic Compounds -

The pollutants commonly classified as hydrocarbons are composed of a wide variety of organic compounds and are discharged into the atmosphere when some of the fuel remains unburned or is only partially burned during the combustion process. Most unburned hydrocarbon emissions result from fuel droplets that were transported or injected into the quench layer during combustion. This is the region immediately adjacent to the combustion chamber surfaces, where heat transfer outward through the cylinder walls causes the mixture temperatures to be too low to support combustion.

Partially burned hydrocarbons can occur because of poor air and fuel homogeneity due to incomplete mixing, before or during combustion; incorrect air/fuel ratios in the cylinder during combustion due to maladjustment of the engine fuel system; excessively large fuel droplets (diesel engines); and low cylinder temperature due to excessive cooling (quenching) through the walls or early cooling of the gases by expansion of the combustion volume caused by piston motion before combustion is completed.[2]

3.3.3.3 Carbon Monoxide -

Carbon monoxide is a colorless, odorless, relatively inert gas formed as an intermediate combustion product that appears in the exhaust when the reaction of CO to CO_2 cannot proceed to completion. This situation occurs if there is a lack of available oxygen near the hydrocarbon (fuel) molecule during combustion, if the gas temperature is too low, or if the residence time in the cylinder is too short. The oxidation rate of CO is limited by reaction kinetics and, as a consequence, can be accelerated only to a certain extent by improvements in air and fuel mixing during the combustion process.[2-3]

3.3.3.4 Smoke and Particulate Matter -

White, blue, and black smoke may be emitted from IC engines. Liquid particulates appear as white smoke in the exhaust during an engine cold start, idling, or low load operation. These are formed in the quench layer adjacent to the cylinder walls, where the temperature is not high enough to ignite the fuel. Blue smoke is emitted when lubricating oil leaks, often past worn piston rings, into the combustion chamber and is partially burned. Proper maintenance is the most effective method of preventing blue smoke emissions from all types of IC engines. The primary constituent of black smoke is agglomerated carbon particles (soot) formed in regions of the combustion mixtures that are oxygen deficient.[2]

3.3.3.5 Sulfur Oxides -

Sulfur oxides emissions are a function of only the sulfur content in the fuel rather than any combustion variables. In fact, during the combustion process, essentially all the sulfur in the fuel is oxidized to SO_2. The oxidation of SO_2 gives sulfur trioxide (SO_3), which reacts with water to give sulfuric acid (H_2SO_4), a contributor to acid precipitation. Sulfuric acid reacts with basic substances to give sulfates, which are fine particulates that contribute to PM-10 and visibility reduction. Sulfur oxide emissions also contribute to corrosion of the engine parts.[2-3]

3.3.4 Control Technologies

Control measures to date are primarily directed at limiting NO_x and CO emissions since they are the primary pollutants from these engines. From a NO_x control viewpoint, the most important distinction between different engine models and types of reciprocating engines is whether they are rich-burn or lean-burn. Rich-burn engines have an air-to-fuel ratio operating range that is near stoichiometric or fuel-rich of stoichiometric and as a result the exhaust gas has little or no excess oxygen. A lean-burn engine has an air-to-fuel operating range that is fuel-lean of stoichiometric; therefore, the exhaust from these engines is characterized by medium to high levels of O_2. The most common NO_x control technique for diesel and dual-fuel engines focuses on modifying the combustion process. However, selective catalytic reduction (SCR) and nonselective catalytic reduction (NSCR) which are post-combustion techniques are becoming available. Controls for CO have been partly adapted from mobile sources.[4]

Combustion modifications include injection timing retard (ITR), preignition chamber combustion (PCC), air-to-fuel ratio adjustments, and derating. Injection of fuel into the cylinder of a CI engine initiates the combustion process. Retarding the timing of the diesel fuel injection causes the combustion process to occur later in the power stroke when the piston is in the downward motion and combustion chamber volume is increasing. By increasing the volume, the combustion temperature and pressure are lowered, thereby lowering NO_x formation. ITR reduces NO_x from all diesel engines; however, the effectiveness is specific to each engine model. The amount of NO_x reduction with ITR diminishes with increasing levels of retard.[4]

Improved swirl patterns promote thorough air and fuel mixing and may include a precombustion chamber (PCC). A PCC is an antechamber that ignites a fuel-rich mixture that propagates to the main combustion chamber. The high exit velocity from the PCC results in improved mixing and complete combustion of the lean air/fuel mixture which lowers combustion temperature, thereby reducing NO_x emissions.[4]

The air-to-fuel ratio for each cylinder can be adjusted by controlling the amount of fuel that enters each cylinder. At air-to-fuel ratios less than stoichiometric (fuel-rich), combustion occurs under conditions of insufficient oxygen which causes NO_x to decrease because of lower oxygen and lower temperatures. Derating involves restricting the engine operation to lower than normal levels of power production for the given application. Derating reduces cylinder pressures and temperatures, thereby lowering NO_x formation rates.[4]

SCR is an add-on NO_x control placed in the exhaust stream following the engine and involves injecting ammonia (NH_3) into the flue gas. The NH_3 reacts with NO_x in the presence of a catalyst to form water and nitrogen. The effectiveness of SCR depends on fuel quality and engine duty cycle (load fluctuations). Contaminants in the fuel may poison or mask the catalyst surface causing a reduction or termination in catalyst activity. Load fluctuations can cause variations in exhaust temperature and NO_x concentration which can create problems with the effectiveness of the SCR system.[4]

NSCR is often referred to as a three-way conversion catalyst system because the catalyst reactor simultaneously reduces NO_x, CO, and HC and involves placing a catalyst in the exhaust stream of the engine. The reaction requires that the O_2 levels be kept low and that the engine be operated at fuel-rich air-to-fuel ratios.[4]

The most accurate method for calculating such emissions is on the basis of "brake-specific" emission factors (pounds per horsepower-hour [lb/hp-hr]). Emissions are the product of the brake-specific emission factor, the usage in hours, the rated power available, and the load factor (the power actually used divided by the power available). However, for emission inventory purposes, it is often easier to assess this activity on the basis of fuel used.

Once reasonable usage and duty cycles for this category were ascertained, emission values were aggregated to arrive at the factors for criteria and organic pollutants presented. Factors in Table 3.3-1 are in pounds per million British thermal unit (lb/MMBtu). Emission data for a specific design type were weighted according to estimated material share for industrial engines. The emission factors in these tables, because of their aggregate nature, are most appropriately applied to a population of industrial engines rather than to an individual power plant. Table 3.3-2 shows unweighted speciated organic compound and air toxic emission factors based upon only 2 engines. Their inclusion in this section is intended for rough order-of-magnitude estimates only.

Table 3.3-3 summarizes whether the various diesel emission reduction technologies (some of which may be applicable to gasoline engines) will generally increase or decrease the selected parameter. These technologies are categorized into fuel modifications, engine modifications, and exhaust after-treatments. Current data are insufficient to quantify the results of the modifications. Table 3.3-3 provides general information on the trends of changes on selected parameters.

3.3.5 Updates Since the Fifth Edition

The Fifth Edition was released in January 1995. Revisions to this section since that date are summarized below. For further detail, consult the memoranda describing each supplement or the background report for this section.

Supplement A, February 1996

No changes.

Supplement B, October 1996

- Text was revised concerning emissions and controls.
- The CO_2 emission factor was adjusted to reflect 98.5 percent conversion efficiency.

Table 3.3-1. EMISSION FACTORS FOR UNCONTROLLED GASOLINE AND DIESEL INDUSTRIAL ENGINES[a]

Pollutant	Gasoline Fuel (SCC 2-02-003-01, 2-03-003-01)		Diesel Fuel (SCC 2-02-001-02, 2-03-001-01)		EMISSION FACTOR RATING
	Emission Factor (lb/hp-hr) (power output)	Emission Factor (lb/MMBtu) (fuel input)	Emission Factor (lb/hp-hr) (power output)	Emission Factor (lb/MMBtu) (fuel input)	
NO_x	0.011	1.63	0.031	4.41	D
CO	6.96 E-03[d]	0.99[d]	6.68 E-03	0.95	D
SO_x	5.91 E-04	0.084	2.05 E-03	0.29	D
PM-10[b]	7.21 E-04	0.10	2.20 E-03	0.31	D
CO_2[c]	1.08	154	1.15	164	B
Aldehydes	4.85 E-04	0.07	4.63 E-04	0.07	D
TOC					
Exhaust	0.015	2.10	2.47 E-03	0.35	D
Evaporative	6.61 E-04	0.09	0.00	0.00	E
Crankcase	4.85 E-03	0.69	4.41 E-05	0.01	E
Refueling	1.08 E-03	0.15	0.00	0.00	E

[a] References 2,5-6,9-14. When necessary, an average brake-specific fuel consumption (BSFC) of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr. To convert from lb/hp-hr to kg/kw-hr, multiply by 0.608. To convert from lb/MMBtu to ng/J, multiply by 430. SCC = Source Classification Code. TOC = total organic compounds.

[b] PM-10 = particulate matter less than or equal to 10 µm aerodynamic diameter. All particulate is assumed to be ≤ 1 µm in size.

[c] Assumes 99% conversion of carbon in fuel to CO_2 with 87 weight % carbon in diesel, 86 weight % carbon in gasoline, average BSFC of 7,000 Btu/hp-hr, diesel heating value of 19,300 Btu/lb, and gasoline heating value of 20,300 Btu/lb.

[d] Instead of 0.439 lb/hp-hr (power output) and 62.7 lb/mmBtu (fuel input), the correct emissions factors values are 6.96 E-03 lb/hp-hr (power output) and 0.99 lb/mmBtu (fuel input), respectively. This is an editorial correction. March 24, 2009

Table 3.3-2. SPECIATED ORGANIC COMPOUND EMISSION FACTORS FOR UNCONTROLLED DIESEL ENGINES[a]

EMISSION FACTOR RATING: E

Pollutant	Emission Factor (Fuel Input) (lb/MMBtu)
Benzene[b]	9.33 E-04
Toluene[b]	4.09 E-04
Xylenes[b]	2.85 E-04
Propylene	2.58 E-03
1,3-Butadiene[b,c]	<3.91 E-05
Formaldehyde[b]	1.18 E-03
Acetaldehyde[b]	7.67 E-04
Acrolein[b]	<9.25 E-05
Polycyclic aromatic hydrocarbons (PAH)	
Naphthalene[b]	8.48 E-05
Acenaphthylene	<5.06 E-06
Acenaphthene	<1.42 E-06
Fluorene	2.92 E-05
Phenanthrene	2.94 E-05
Anthracene	1.87 E-06
Fluoranthene	7.61 E-06
Pyrene	4.78 E-06
Benzo(a)anthracene	1.68 E-06
Chrysene	3.53 E-07
Benzo(b)fluoranthene	<9.91 E-08
Benzo(k)fluoranthene	<1.55 E-07
Benzo(a)pyrene	<1.88 E-07
Indeno(1,2,3-cd)pyrene	<3.75 E-07
Dibenz(a,h)anthracene	<5.83 E-07
Benzo(g,h,l)perylene	<4.89 E-07
TOTAL PAH	1.68 E-04

[a] Based on the uncontrolled levels of 2 diesel engines from References 6-7. Source Classification Codes 2-02-001-02, 2-03-001-01. To convert from lb/MMBtu to ng/J, multiply by 430.
[b] Hazardous air pollutant listed in the *Clean Air Act*.
[c] Based on data from 1 engine.

Table 3.3-3. EFFECT OF VARIOUS EMISSION CONTROL TECHNOLOGIES ON DIESEL ENGINES[a]

Technology	Affected Parameter	
	Increase	Decrease
Fuel modifications		
Sulfur content increase	PM, wear	
Aromatic content increase	PM, NO_x	
Cetane number		PM, NO_x
10% and 90% boiling point		PM
Fuel additives		PM, NO_x
Water/Fuel emulsions		NO_x
Engine modifications		
Injection timing retard	PM, BSFC	NO_x, power
Fuel injection pressure	PM, NO_x	
Injection rate control		NO_x, PM
Rapid spill nozzles		PM
Electronic timing & metering		NO_x, PM
Injector nozzle geometry		PM
Combustion chamber modifications		NO_x, PM
Turbocharging	PM, power	NO_x
Charge cooling		NO_x
Exhaust gas recirculation	PM, power, wear	NO_x
Oil consumption control		PM, wear
Exhaust after-treatment		
Particulate traps		PM
Selective catalytic reduction		NO_x
Oxidation catalysts		TOC, CO, PM

[a] Reference 8. PM = particulate matter. BSFC = brake-specific fuel consumption.

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E-7 LA Kiln SO2 Source Test- 5/20-21/1991

Sulfur Emission Factor Information
May 20, 1991 Source Test Information

Reference 4

SOUTH
COAST
ENVIRONMENTAL
COMPANY

SOURCE TEST REPORT

GREAT WESTERN MALTING
P. O. BOX 1529
VANCOUVER, WA 98668-1529

EQUIPMENT LOCATION:

5945 SOUTH MALT AVENUE
LOS ANGELES, CA 90040-3591

TEST DATE:

MAY 20 AND 21, 1991

ISSUE DATE:

JUNE 10, 1991

PARAMETERS MEASURED:

PARTICULATE AND SO_x EMISSIONS

TESTED BY:

SOUTH COAST ENVIRONMENTAL COMPANY
1915 McKINLEY AVENUE, SUITE E
LA VERNE, CA 91750

REPORT NO: T1294

TESTED BY: Kelt Shannon

REVIEWED BY: [signature]

SOUTH
COAST
ENVIRONMENTAL
COMPANY

TABLE OF CONTENTS

SOUTH
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ENVIRONMENTAL
COMPANY

I. SELECTED RESULTS

GREAT WESTERN MALTING
JOB NO. T1294
MALTING KILNS #1 AND #2

I. SELECTED RESULTS

A. MALTING KILN #1 - SO_2 EMISSIONS

RUN NO.	SULFURIC ACID MIST (LB/HR)	SO_2 (PPM)	SO_2 (LB/HR)
1 (South)	0.03	12.75	6.66
2 (Middle)	0.00	12.55	5.28
3 (North)	0.03	16.09	7.46
		TOTAL	19.40

B. MALTING KILN #2 - SO_2 EMISSIONS

RUN NO.	SULFURIC ACID MIST (LB/HR)	SO_2 (PPM)	SO_2 (LB/HR)
1 (South)	0.00	7.43	4.53
2 (Middle)	0.00	4.15	2.06
3 (North)	0.01	10.23	5.32
		TOTAL	11.91

PARTICULATE RESULTS

MALTING KILN	GRAIN LOADING (GR/DSCF)	LB/HR	SCAQMD APPLICABLE RULE
#1	0.0000	0.011	404 and 405
#2	0.0001	0.114	404 and 405

GREAT WESTERN MALTING
JOB NO. T1294
MALTING KILNS #1 AND #2

I. SELECTED RESULTS

A. MALTING KILN #1 - SO_2 EMISSIONS

RUN NO.	SULFURIC ACID MIST (LB/HR)	SO_2 (PPM)	SO_2 (LB/HR)
1 (South)	0.03	12.75	6.66
2 (Middle)	0.00	12.55	5.28
3 (North)	0.03	16.09	7.46
	use 0.03	TOTAL	19.40

$\frac{6.467}{30} = 0.2156$

$\frac{0.03}{30} = 0.001 \frac{\text{lb } H_2SO_4}{\text{lb S}}$

avg = 6.467

pg 25 - 60 lb/hr SO_2 injection rate $SO_2 = \frac{32.06}{(32.06 + 15.9994 \times 2)}$ = 0.5 sulfur fraction

30 lb S during tests

B. MALTING KILN #2 - SO_2 EMISSIONS

RUN NO.	SULFURIC ACID MIST (LB/HR)	SO_2 (PPM)	SO_2 (LB/HR)
1 (South)	0.00	7.43	4.53
2 (Middle)	0.00	4.15	2.06
3 (North)	0.01	10.23	5.32
	use 0.01	TOTAL	11.91

avg = 3.97

H_2SO_4 em. factor $= \frac{0.01 \text{ lb}}{30 \text{ lb S}} = 0.00033$ SO_2 em. fac. $\frac{3.97}{30} = 0.1323$

PARTICULATE RESULTS

MALTING KILN	GRAIN LOADING (GR/DSCF)	LB/HR	SCAQMD APPLICABLE RULE
#1	0.0000	0.011	404 and 405
#2	0.0001	0.114	404 and 405

	H_2SO_4	SO_2
kiln 1 -	0.001 lb/lb S	0.2156 lb/lb S
kiln 2 -	0.00033	0.1323

use higher of the two

or max, assuming 10 lb/hr SO_2 inject.

⇒ 0.006 lb H_2SO_4/lb S

1.492 lb SO_2/lb S

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II. INTRODUCTION

II. INTRODUCTION

On May 20 and 21, 1991, South Coast Environmental Company (SCEC) conducted a source test on two (2) malting kilns, Malt House 1 and 2. The kilns are owned and operated by Great Western Malting (GWM) located at 5945 South Malt Avenue, Los Angeles, CA.

The purpose of the test was to demonstrate compliance with SCAQMD Permits to Operate.

The malting kilns methodology for SO_2 testing was SCAQMD Method 6.1. Each kiln has three exhaust openings, due to the presence of cyclonic flow, stack extensions were constructed in order to comply with SCAQMD Method 1.1 and 2.1 testing requirements. These stack extensions effectively eliminated the presence of cyclonic flow. Three (3) simultaneous runs were performed on each kiln in order to obtain a complete composite sample. Additionally, a single particulate run, SCAQMD Method 5.2, was performed in conjunction with one of the SO_2 runs (middle stack). Particulate emissions were then multiplied by a factor three (3) to yield a representative emission rate from each kiln house. SCEC performed all sampling and analysis and adhered to all QA/QC requirements as specified by SCAQMD testing methods.

The testing personnel for SCEC included Leslie A. Johnson - Source Test Manager, Keith B. Shannon - Project Engineer, Russell P. Logan - Project Engineer, and Shannan M. Wilcox - Site Technician. On-site testing was coordinated by Irv Thompson from GWM. Testing efforts were witnessed by Fred Minassian from SCAQMD.

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III. EQUIPMENT AND PROCESS DESCRIPTION

III. EQUIPMENT AND PROCESS DESCRIPTION

The malting houses are filled with grain then injected with SO_2 in order to kill or inhibit the formation of nitrosamines and the growth of undesired bacteria in the grain.

Each kiln is operated on a 16 hour cycle on a rotating basis. This corresponds to 300 lb/day of SO_2 injection at varying rates for 5 hours, with a permit limit of 308 lb/day.

The kiln dimensions and process rates are as follows.

	House #1	House #2
Kiln Dimensions:		
Upper	99'8" Length 33' Width 36" Depth	110' Length 33' Width 36" Depth
Lower	98'8" Length 30' Width 30" Depth	108'10" Length 33' Width 32" Depth
Stack Dimensions	5'0" x 4'4"	6'6" x 4'8"
Material (Dry Product Weight):		
Upper	140,000 lbs.	180,000 lbs.
Lower	140,000 lbs.	180,000 lbs.

T12941

SOUTH COAST ENVIRONMENTAL COMPANY

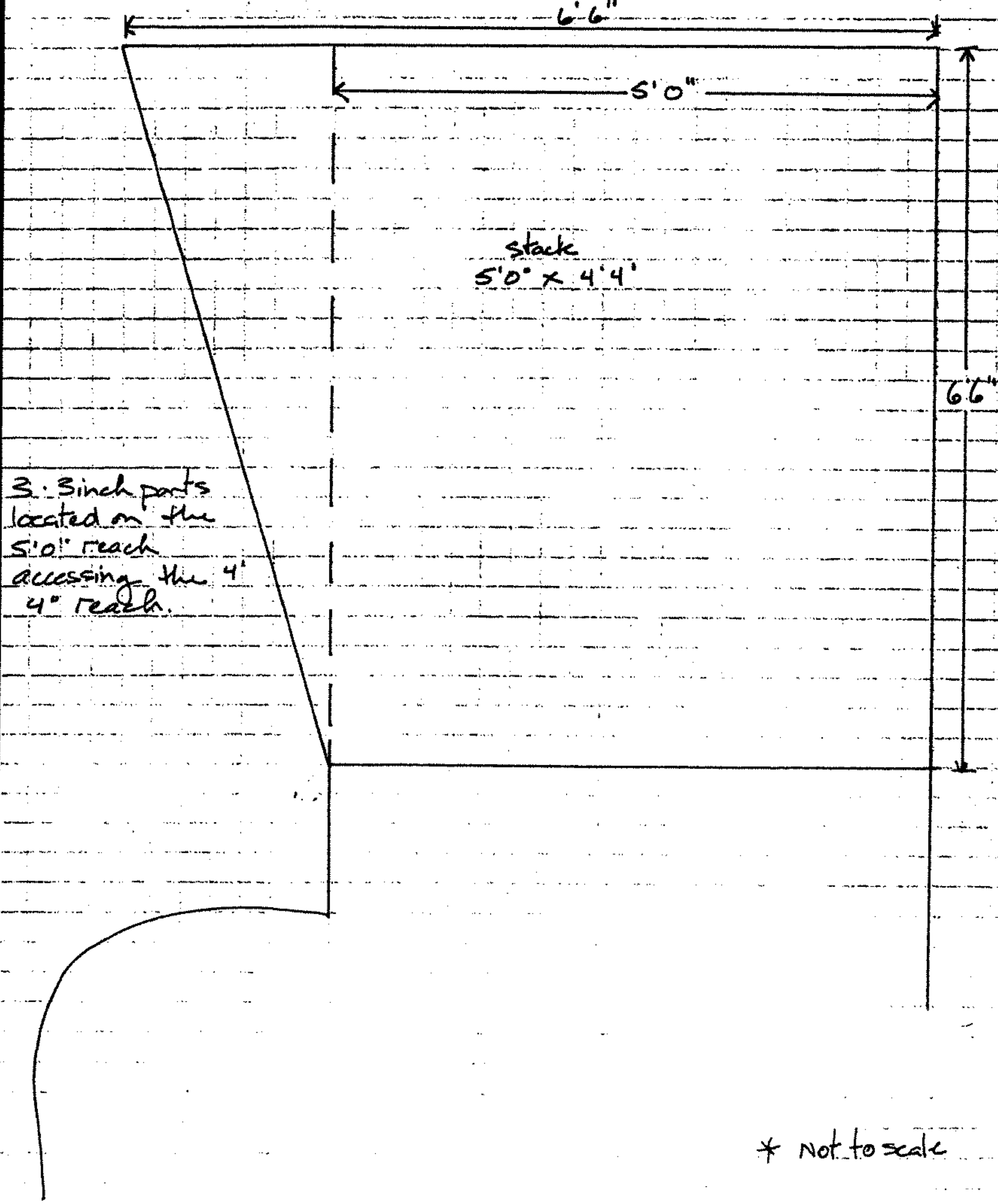
1915 McKinley Ave., Ste. E
La Verne, CA 91750
714-596-6540

PROJECT: Great Western Malting

PROJECT #: T-1294 DATE:

BY: CAJ CHECKED BY: PAGE ____ OF ____

House I



* Not to scale

SOUTH COAST ENVIRONMENTAL COMPANY

1915 McKinley Ave., Ste. E
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PROJECT: Great Western Malting

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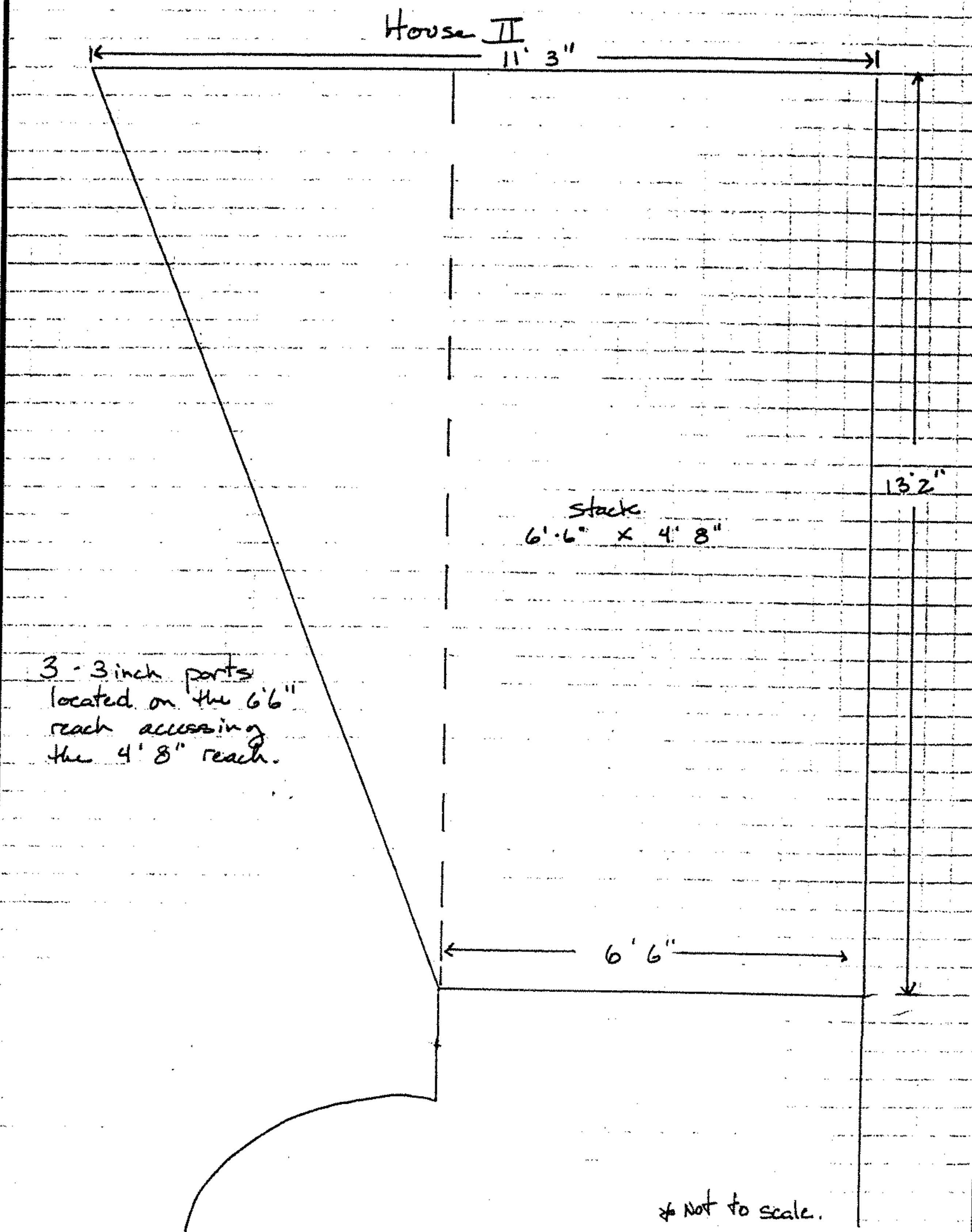

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IV. SO_2 AND PARTICULATE RESULTS

COMPANY: GREAT WESTERN MALTING
REPORT #:T-1294
DATE: MAY 21, 1991
UNIT: KILN #1

METHOD 6
SOX/SO2 RESULTS

STACKS:	SOUTH	MIDDLE	NORTH
RUN #:	#1	#2	#3
Begining time	1100	1100	1100
Ending Time	1212	1216	1212
Vm (std), dscf @ 60' F	39.94	29.61	35.62
Q std, dscfm @ 60' F	51576	41131	45751
Sulfuric acid mist, mg.............	0.18	0.00	0.16
Sulfur Trioxide in 2-Propanol, mg...	0.00	0.35	0.00
Sulfur Dioxide in H2O2, mg..........	39.02	28.46	43.89
SULFURIC ACID MIST (LB/HR)..........	0.03	0.00	0.03
EMISSIONS OF SO2 (PPM)..............	12.75	12.55	16.09
TOTAL SULFUR COMPOUNDS (PPM)........	13.06	12.94	16.46
TOTAL SULFUR COMPOUNDS (LB/HR)......	6.82	5.39	7.63
TOTAL SULFUR OXIDES AS SO2 (PPM)....	12.75	12.67	16.09
TOTAL SULFUR OXIDES AS SO2 (LB/HR)..	6.66	5.28	7.46

COMPANY: GREAT WESTERN MALTING
REPORT #:T-1294
DATE: MAY 20, 1991
UNIT: KILN #2

METHOD 6
SOX/SO2 RESULTS

STACKS:	SOUTH	MIDDLE	NORTH
RUN #:	#1	#2	#3
Begining time	1222	1225	1218
Ending Time	1322	1334	1318
Vm (std), dscf @ 60' F	34.69	44.94	30.42
Q std, dscfm @ 60' F	52867	48519	48506
Sulfuric acid mist, mg..............	0.00	0.00	0.03
Sulfur Trioxide in 2-Propanol, mg...	3.43	0.15	1.75
Sulfur Dioxide in H2O2, mg..........	19.74	14.29	23.84
SULFURIC ACID MIST (LB/HR)..........	0.00	0.00	0.01
EMISSIONS OF SO2 (PPM)..............	7.43	4.15	10.23
TOTAL SULFUR COMPOUNDS (PPM)........	8.64	4.28	11.07
TOTAL SULFUR COMPOUNDS (LB/HR)......	4.63	2.10	5.44
TOTAL SULFUR OXIDES AS SO2 (PPM)....	8.46	4.19	10.83
TOTAL SULFUR OXIDES AS SO2 (LB/HR)..	4.53	2.06	5.32

COMPANY: GREAT WESTERN MALTING
DATE: MAY 21, 1991
UNIT: KILN #1; MIDDLE STACK
REPORT #:T-1294

PARTICULATE INPUT FOR FILTER TEMP > 200 F

LAB ANALYSIS

A. FILTER CATCH	0.6000	mg
B. (1) FILTER ACID	0.0000	mg
(2) FILTER TOTAL SULFATE	0.0000	mg
C. PROBE CATCH	0.0000	mg
D. (1) PROBE ACID	0.0000	mg
(2) PROBE TOTAL SULFATE	0.0000	mg
E. IMPINGER CATCH	0.0000	mg
F. (1) IMPINGER ACID	0.0000	mg
(2) IMPINGER TOTAL SULFATE	0.0000	mg
G. ORGANIC EXTRACT	0.5800	mg
H. H2SO4.2H20 FROM SOx TRAIN THIMBLE		mg
I. PARTICULATE TRAIN CORRECTED GAS VOLUME METERED		mg
J. SOx TRAIN CORRECTED GAS VOLUME METERED	41.440	dscf
K. PRORATED H2SO4.2H20 MASS ((H*I)/J)	41.440	dscf
	0	mg

FILTER TEMPERATURE GREATER THAN 200'F

L. TOTAL PARTICULATE (A-B2+C-D2+E-F2+G+K)	0.0200	mg
M. SOLID PARTICULATE (L-G-K)	0.0200	mg
N. TOTAL PARTICULATE (CORRECTED FOR AMMONIUM SULFATE) (A-B2+C-D2+E-F(1)+G+K-[F(2)-F(1)]*132/134)	0.0197	mg
O. SOLID PARTICULATE (CORRECTED FOR AMMONIUM SULFATE) (N-G-J)	0.0197	mg

PARTICULATE RESULTS

GR/DSCF	0.0000
GR/SCF	0.0000
GR/DSCF @ 12% CO2	0.0012
LB/HR	0.0036

ADDITIONAL INFORMATION:

VM STD(DSCF)	Tstk	%CO2	%O2	%H2O	DSCFM	%ISO
29.61	544	0.1	20.9	4.3	41131	94.6

COMPANY: GREAT WESTERN MALTING
DATE: MAY 20, 1991
UNIT: KILN #2; MIDDLE STACK
REPORT #:T-1294

PARTICULATE INPUT FOR FILTER TEMP > 200 F

LAB ANALYSIS

A. FILTER CATCH		
B. (1) FILTER ACID	0.0000	mg
(2) FILTER TOTAL SULFATE	0.0000	mg
C. PROBE CATCH	0.0000	mg
D. (1) PROBE ACID	0.0000	mg
(2) PROBE TOTAL SULFATE	0.0000	mg
E. IMPINGER CATCH	0.0000	mg
F. (1) IMPINGER ACID	0.5600	mg
(2) IMPINGER TOTAL SULFATE	0.0000	mg
G. ORGANIC EXTRACT	0.2892	mg
H. H2SO4.2H20 FROM SOx TRAIN THIMBLE		mg
I. PARTICULATE TRAIN CORRECTED GAS VOLUME METERED		mg
J. SOx TRAIN CORRECTED GAS VOLUME METERED	41.440	dscf
K. PRORATED H2SO4.2H20 MASS ((H*I)/J)	41.440	dscf
	0	mg

FILTER TEMPERATURE GREATER THAN 200'F

L. TOTAL PARTICULATE (A-B2+C-D2+E-F2+G+K)	0.2708	mg
M. SOLID PARTICULATE (L-G-K)	0.2708	mg
N. TOTAL PARTICULATE (CORRECTED FOR AMMONIUM SULFATE) (A-B2+C-D2+E-F(1)+G+K-[F(2)-F(1)]*132/134)	0.2668	mg
O. SOLID PARTICULATE (CORRECTED FOR AMMONIUM SULFATE) (N-G-J)	0.2668	mg

PARTICULATE RESULTS

GR/DSCF	0.0001
GR/SCF	0.0001
GR/DSCF @ 12% CO2	0.0110
LB/HR	0.0381

ADDITIONAL INFORMATION:

VM STD(DSCF)	Tstk	%CO2	%O2	%H2O	DSCFM	%ISO
44.94	565	0.1	20.9	8	48519	97.2

V. SAMPLING AND ANALYTICAL PROCEDURES

South Coast Environmental Company
1915 McKinley Avenue, Suite E
La Verne, CA 91750

SAMPLING AND ANALYTICAL PROCEDURES

SCAQMD METHOD #1 - SAMPLING AND VELOCITY TRAVERSE FOR STATIONARY SOURCES

A preliminary source test site assessment was performed prior to the source test in order to determine applicable testing port locations and sample point traverse locations. The stack diameter, and the distance from sample ports to disturbances, i.e. bends, flanges, etc..., both upstream and downstream, were measured. This information was utilized to determine the minimum number of sampling points per traverse, and the distance from the inner stack wall to each sample point location. Additionally, this method takes into account cyclonic flow patterns and in-situ stratified pollutant concentrations.

SCAQMD METHOD #2 - VELOCITY AND VOLUMETRIC FLOW RATE

The velocity of the gas stream was determined by using an "s" type pitot tube, a magnehelic differential pressure gauge, and type "K" thermocouple with a digital temperature measuring device. The calibrated pitot tube was connected to the magnehelic gauge and leak checked. A temperature and delta P was obtained at each traverse point, and a duct static pressure was measured and recorded. The dry volumetric flow rate was determined from the gas velocity data, stack pressure, stack gas moisture content, stack gas molecular weight, and cross-sectional area of duct.

SCAQMD METHOD #3 - GAS ANALYSIS FOR DRY MOLECULAR WEIGHT AND EXCESS AIR

A gas sample was extracted from the stack using a tedlar bag, teflon line, stainless steel probe, leak free pump (if necessary), and leak free container (if necessary). Alternatively, the gas sample may be obtained at the outlet of the gas meter of a collection train, or the bypass of our SCAQMD Method 100.1 manifold. The gas sample was analyzed for CO_2 and O_2 using an orsat analyzer. Prior to analysis all orsat reagents were checked against manufacturer expiration dates, and a leak check was performed on the manifold of the orsat apparatus. The sample gas was passed through each impactor/bubbler three times before a percent reading was recorded.

SAMPLING AND ANALYTICAL PROCEDURES

SCAQMD METHOD #4 - DETERMINATION OF MOISTURE CONTENT IN STACK GASES

Moisture content was determined using a sampling train consisting of a stainless steel probe, teflon line, four impingers in an ice water bath, leak free pump, vacuum gauge, and temperature compensated dry gas meter. Prior to sampling a leak check of the sampling train was performed to insure system integrity. Additionally, tare weights of the charged individual impingers were recorded using a triple beam balance capable of weighing to the nearest 0.1 grams or less.

After sampling, the final weights of each impinger were determined and recorded. Percent moisture content was calculated from the weight of water collected and the dry gas volume sampled.

CALCULATIONS

$$\text{Moisture } (B_w) = \frac{\text{Vwstd}}{\text{Vmstd} + \text{Vwstd}} \times 100$$

Where:

$$\text{Vwstd} = \frac{0.0464 \text{ ft}^3}{\text{ml}} * \text{Vol } H_2O \text{ Collected (ml)}$$

$$\text{Vmstd} = \text{Y Meter} * \frac{520°R}{29.92 \text{ in Hg}} * \frac{\text{Vol Metered}}{\text{Temp. Meter}} * \text{Pres. Meter.}$$

ST54

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SAMPLING AND ANALYTICAL PROCEDURES

SCAQMD METHOD #5.2 - PARTICULATE EMISSIONS

A series of preliminary measurements were made prior to conducting the particulate test. SCAQMD Methods 1, 2, and 3 were performed to determine location and number of traverse points, average gas velocity, and gas molecular weight, respectively. Percent moisture content was estimated using a psychometric chart or combustion analysis of the fixed gases. The results of these measurements were used to determine the appropriate nozzle size for isokinetic sampling.

The Method #5.2 apparatus was prepared on-site in our mobile emissions laboratory. The absorption train was charged with freshly prepared chemicals (see Field Data Sheets for actual contents), weighed on a calibrated triple beam balance to the nearest 0.1 grams, and assembled. The probe was brushed out and rinsed with distilled water and acetone, and the filter placed in the filter holder. The sampling apparatus was sealed and transported to the sampling site where it was assembled and leak tested at 15 inches of mercury vacuum. The probe and filter temperatures were set at 180-200 degrees F, and the probe was positioned into the duct at the first traverse point with the nozzle out of the flow.

The nozzle was positioned into the gas flow and the vacuum pump was started immediately and adjusted to obtain an isokinetic sample rate. A complete traverse was performed while sampling at a minimum of two minutes per sample point (see Field Data Sheets for actual duration). Upon completion of the traverse the vacuum pump was turned off and the probe was transferred into the next sample port where an identical traverse was performed. Duct conditions (temperature, delta-P) and sampling conditions (meter temperature, meter volume, meter pressure, filter temperature, sample line temperature, impinger temperature, and absorption train vacuum) were monitored and recorded regularly for each sample point.

Upon completion of sampling, the apparatus was leak checked at a vacuum greater than the highest observed vacuum. Any leak was recorded and the apparatus was sealed and transported to the mobile laboratory. The filter-to-impinger line was rinsed with a known amount of distilled water into the first impinger.

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SAMPLING AND ANALYTICAL PROCEDURES

ANALYSIS

The probe, nozzle, and filter housing were washed as per Method #5 and quantitatively transferred to a clean labeled bottle.

The filter and any loose particulate was carefully removed from the filter holder with tweezers. The filter was then placed into a labeled petri dish and transported to the SCEC laboratory. The nozzle, probe, and filter top housing were rinsed and brushed three times with distilled water and acetone. The sample fractions were combined, bottled, labeled, and fluid levels marked for transportation to SCEC laboratory for analysis. Aliquots of the acetone and distilled water were similarly treated for blank analysis.

The absorption train was inspected for abnormalities and disassembled. The impingers were weighed on a triple beam balance for a percent moisture determination. The contents of the impingers were quantitatively transferred into separate bottles, sealed, labeled, and fluid level marked for transportation to the SCEC laboratory for analysis, if required. Aliquots of the reagent grade impinger contents were saved for blank analysis.

The filter was transferred to an oven and heated at 105 degrees C for 2-3 hours and then placed in a desiccator for 24 hours. The filter was then weighed on a Mettler digital balance to the nearest 0.01 mg or one percent of the total filtrate weight (weighed to a constant weight).

The nozzle, probe, and filter top wash was examined for any leakage during transportation and transferred to a tared evaporation dish. The wash was then evaporated at an elevated temperature - below the boiling point of the wash - with occasional stirring. The dish and wash residue were then desiccated and weighed to a constant weight.

If required by the regulatory agency, the contents of the first impinger were recovered and diluted volumetrically to a known volume. An aliquot of this sample was then evaporated, desiccated, and weighed to a constant weight.

The net weight of particulate was calculated from the two fractions (three fractions including the impinger contents if required). Concentrations (gr/dscf) and emissions (lb/hr) or other applicable units were then calculated and reported.

ST55a

SAMPLING AND ANALYTICAL PROCEDURES

SCAQMD METHOD #6.1 - SO_2

A series of preliminary measurements were made prior to conducting the test. SCAQMD Methods 1, 2, and 3 were performed to determine location and number of traverse points, average gas velocity, and gas molecular weight. Percent moisture content was estimated using a psychometric chart. The results of these measurements were used to determine lb/hr of SO_2 emissions.

The Method #6.1 apparatus was prepared on-site in our mobile emissions laboratory. The absorption train was charged with freshly prepared chemicals weighed on a calibrated triple beam balance to the nearest 0.1 grams, and assembled. The first impinger was filled with 100 ml of IPA, the second impinger was left empty, the third and fourth impingers were filled with H_2O_2, and the fifth impinger was filled with approximately 400 grams of silica gel. The probe was brushed out and rinsed with distilled water and acetone. The sampling apparatus was sealed and transported to the sampling site where it was assembled and leak tested at 15 inches of mercury vacuum. Sampling was conducted until 20 liters of sample gas was collected.

Upon completion of sampling, the apparatus was leak checked at a vacuum greater than the highest observed vacuum. The leak was recorded and the apparatus was sealed and transported to the mobile laboratory. The probe-to-impinger line was rinsed with a known amount of IPA into the first impinger.

ANALYSIS

The absorption train was inspected for abnormalities and disassembled. The impingers were weighed on a triple beam balance for a percent moisture determination. The contents of the impingers were quantitatively transferred into separate bottles, sealed, labeled, and fluid level marked for transportation to the SCEC laboratory for analysis, if required.

The sample containers were examined for any leakage during transportation.

Aliquots of the samples were then prepared and titrated with 0.01N $Ba(ClO_4)_2$ to a pink end point using Thorin indicator. Replicate titrations were performed until they agreed within 1 percent or 0.05 ml, whichever is greater.

CALCULATIONS

Acid,

as So_3, mg = A $= (V_a - V_b) \times N_n \times 80.07/2 \times AF$

Sulfate,

as SO_3, mg = B $= (V_a - V_b) \times N_b \times 80.07/2 \times AF$

Sulfur Dioxide,

as SO_2, mg = C $= (V_a - V_b) \times N_6 \times 64.06/2 \times AF$

Sulfuric Acid Mist,

Emission of $H_2SO_4 \cdot 2H_2O$, lb/hr

$$= \frac{(1.32 \times 10^{-4})(A)(Q)}{(V_M)}$$

Sulfur Dioxide Concentration,

$$\text{Emission of } SO_2\text{, ppm} = \frac{(835.54)(C)}{(V_M)(64)}$$

Total Sulfur Compounds expressed as SO_2

$$\text{Concentration, ppm} = \frac{[(A)(0.4776)+(B)(0.8)+C](835.54)}{(V_M)(64)}$$

Total Sulfur Oxides expressed as SO_2

$$\text{Concentration, ppm} = \frac{[(B)(0.8)+C](835.54)}{(V_M)(64)}$$

NOMENCLATURE

V_M	=	Corrected gas volume metered, dscf
Q	=	Flow rate, dscfm
A	=	Sulfuric acid mist in the probe and thimble, expressed as $H_2SO_4 \cdot 2H_2O$, mg (if reported as SO_3, multiply by 1.675)
B	=	Sulfur trioxide in 2-propanol expressed as SO_3, mg
C	=	Sulfur dioxide in H_2O_2, mg
V_a	=	Average sample titration volume, ml
V_b	=	Average blank titration volume, ml
N_n	=	Normality of NaOH, mg/ml
N_b	=	Normality of $Ba(ClO_4)_2$, mg/ml
80.07/2	=	Equivalent weight of SO_3
AF	=	Aliquot factor (sample volume/analytical aliquot volume)

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APPENDICES

SOUTH COAST ENVIRONMENTAL COMPANY

APPENDIX A

KILN OPERATION CONDITIONS/SO_2 INJECTION RATES

GREAT WESTERN MALTING

SCEC JOB NO. T1294

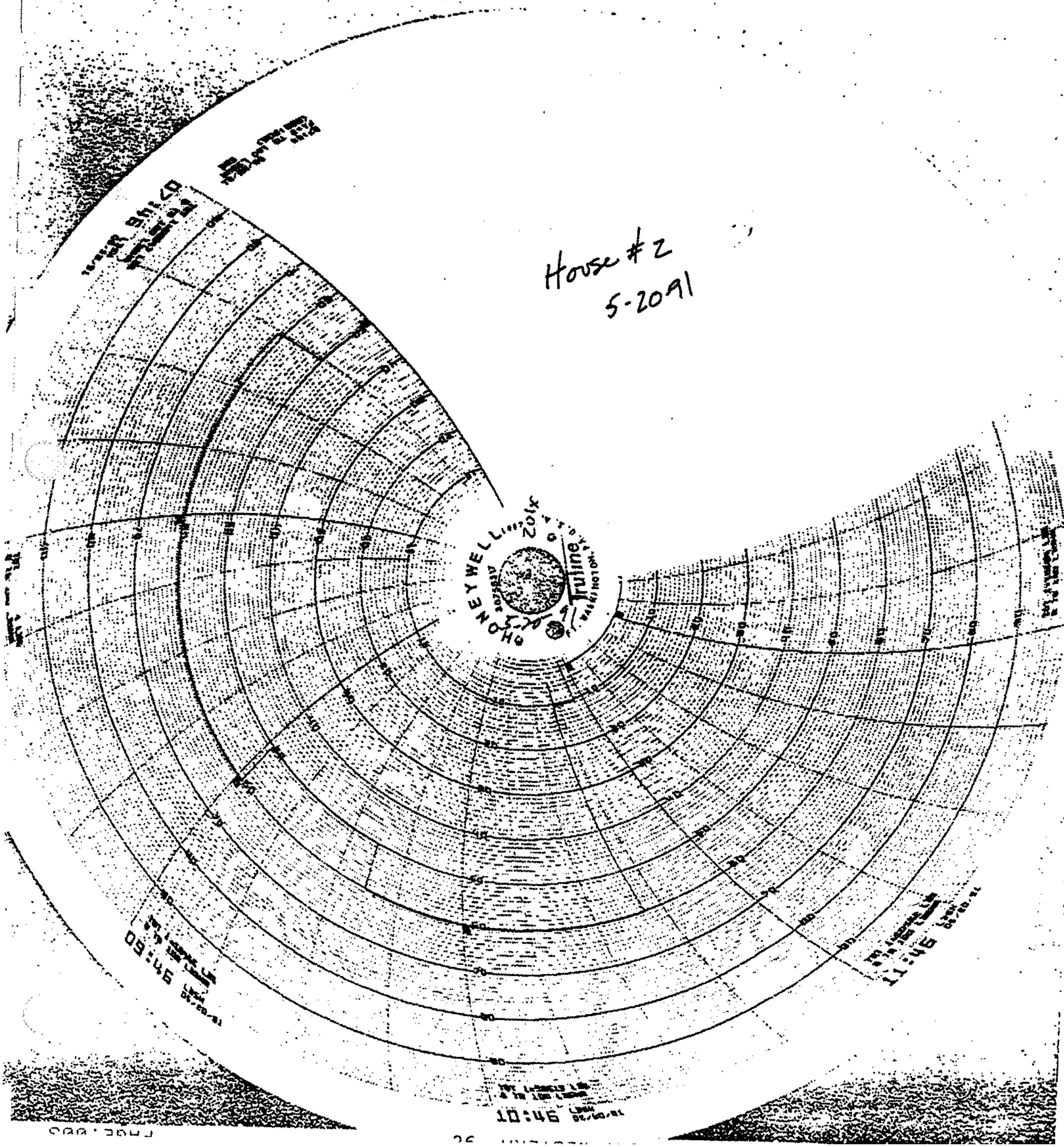
TEST DATES: MAY 20 and 21, 1991

UNITS TESTED: Malt House #1 and #2

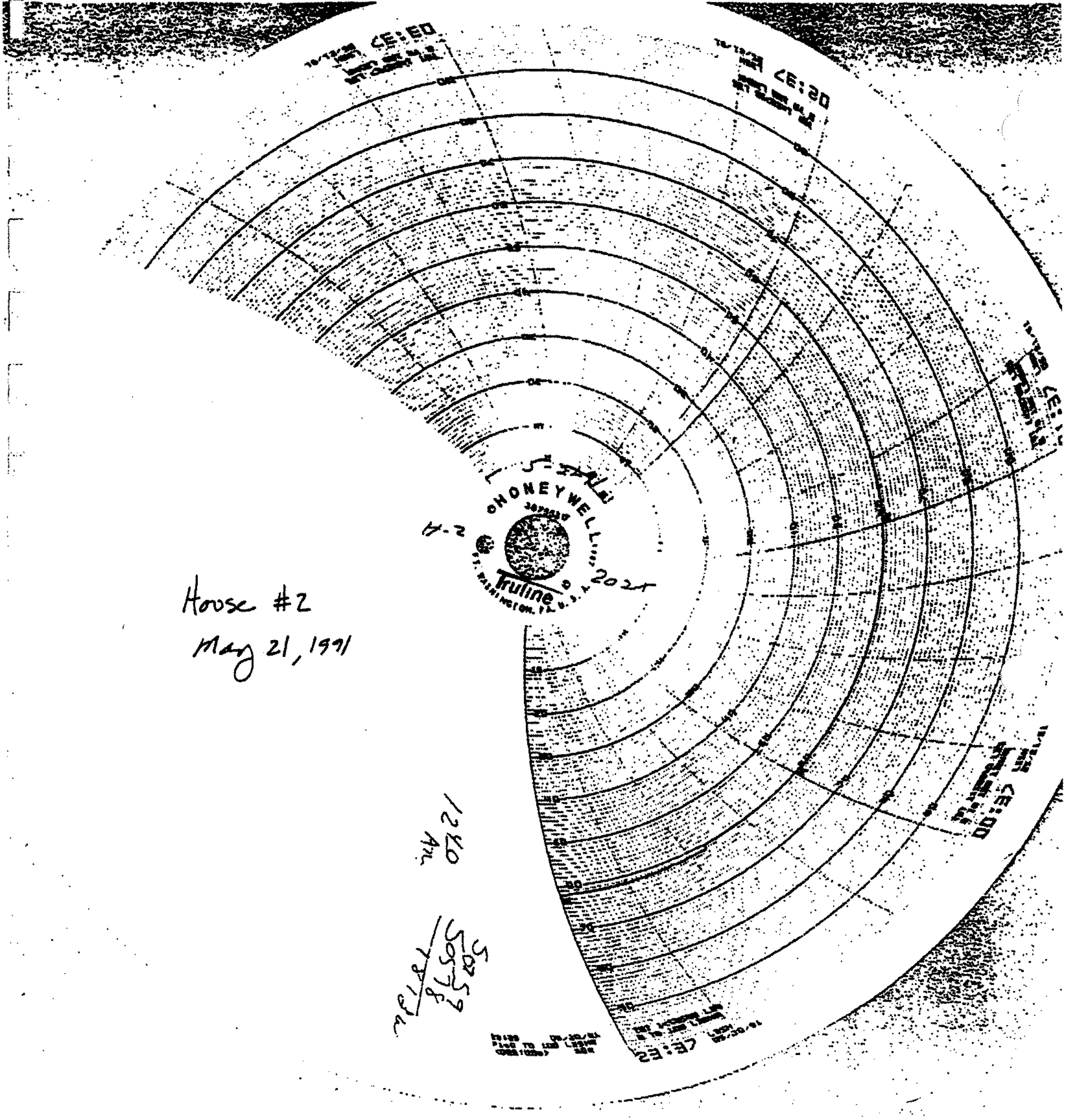
SO_2 INJECTION SCHEDULE

5 lbs/hr

DATE	MALT HOUSE	START TIME	SO_2 INJECTION RATE	DURATION OF INJECTION
May 20	#1	5p	60 lb/hr 10 lb/hr	3.0 hours 2.0 hours
May 20	#2	9a	60 lb/hr 10 lb/hr	3.0 hours 2.0 hours
May 21	#1	9a	60 lb/hr 10 lb/hr	3.0 hours 2.0 hours
May 21	#2	5p and 1a	60 lb/hr 10 lb/hr	3.0 hours 2.0 hours

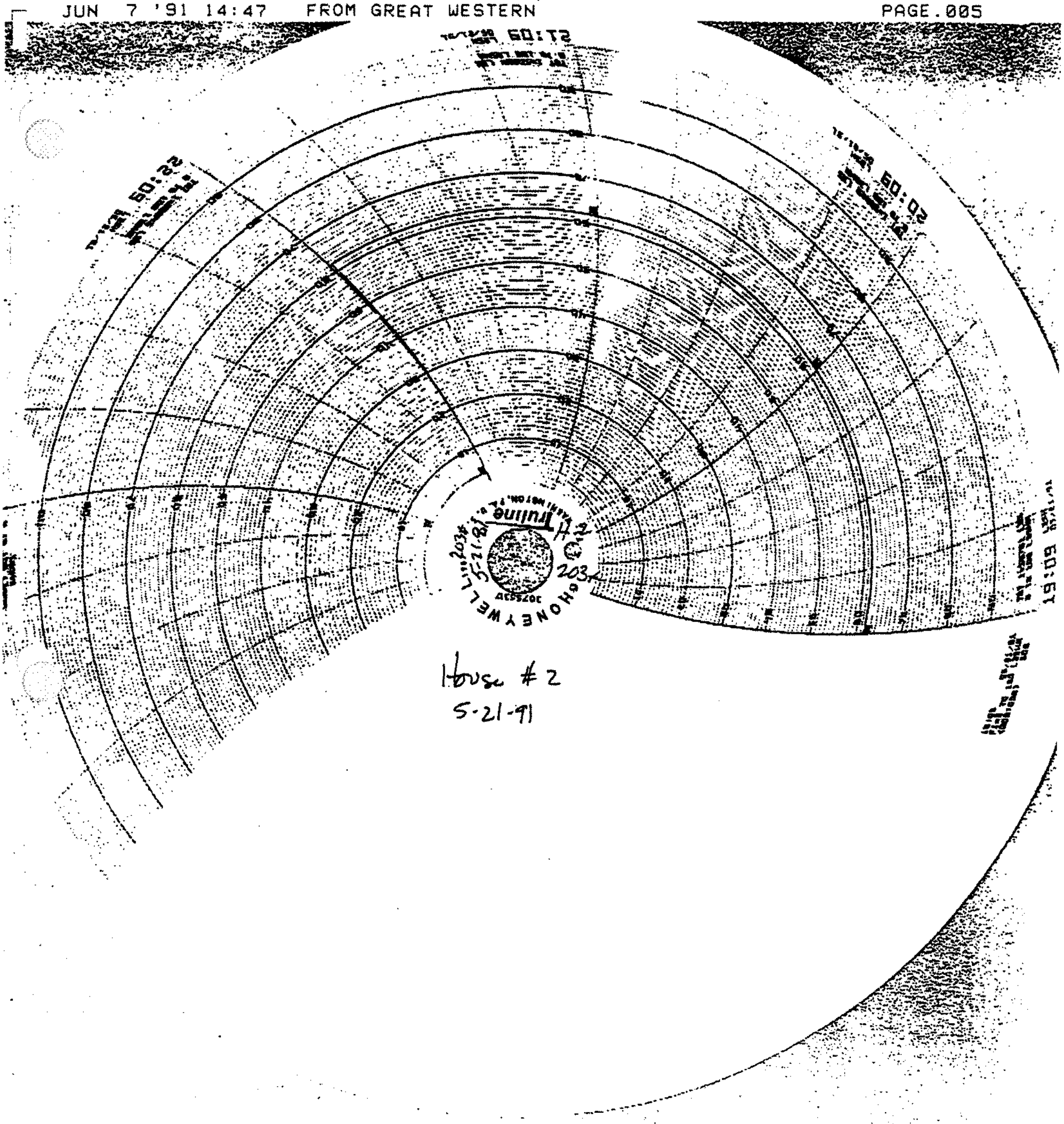


House #2
5-20-91



House #2
May 21, 1991

1240 Am


House #2
5-21-91

SOUTH
COAST
ENVIRONMENTAL
COMPANY

APPENDIX B

ANALYTICAL LAB RESULTS

Client: GWM

Report #: T-1294

Test Date: 5-21-91

Analyst: HPG

Kiln #1 South stack

TITRIMETRIC ANALYSIS

Sample I.D./Run #	Total Sample (mls)	Aliquot mls	Normality	Titrant mls	mg
P/N #1	213	25	0.008557	~~0.15~~	
"	"	"	"	0.11	0.00
"	"	"	"	0.12	
IPA	248	25	"	0.09	0.00
"	"	"	"	0.09	
H_2O_2	274	"	"	~~13.22~~	
"	"	"	"	13.04	39.020
"	"	"	"	13.02	
filter	100	"	"	0.31	
"	"	"	"	0.30	0.1781

COMMENTS:

ST18

Client: GWM

Analyst: AFG

Report #: T1294

Test Date: 5-21-91

Kiln #1 middle stack

TITRIMETRIC ANALYSIS

Sample I.D./Run #	Total Sample (mls)	Aliquot mls	Normality	Titrant mls	mg
IPA	266	25	0.008557	0.28	
"	"	"	"	0.26	
			Blanked =	0.095	a 34
H_2O_2	308	"	"	~~8.63~~	
"	"	"	"	8.46	
"	"	"	"	8.47	~~28~~
			Blanked	8.435	2846
IPA Filter Extract	100	"	"	0.15	
"	"	"	"	0.16	
			Blanked	0.00	
~~P/N~~ P/N	50	"	"	0.06	
	"	"	"	0.04	
				0.00	

COMMENTS:

ST18

Client: Gwm

Report #: T 1294

Analyst: AFG

Test Date: 5-21-91

Kiln #1

GRAVIMETRIC ANALYSIS

1 Fraction: Probes and Nozzle Washings

#1	#2	#3	
Date: 5-24-91 Time: 17^{30}	Date: 5-31-91 Time: 9^{00}	Date: 5-31-91 Time: 12^{00}	
Final: ~~75.5570~~ Tare:	75.5532	75.5534	AVERAGE 75.5533 grms. 75.5535 grms.
		NET:	0.0000 mg.

Fraction: Filter

Filter No:

#1	#2	#3	
Date: ~~1800~~ 5-24-91 Time: 10^{00}	Date: 5-24-91 Time: 17^{30}	Date: Time:	
Final: 0.4958 Tare:	0.4960		AVERAGE 0.4959 grms. 0.4953 grms.
		NET:	0.0006 mg.

9 Fraction: Condensables

Aliquot: 100 Total Sample: 266

#1	#2	#3	
Date: 5-24-91 Time: 17 30	Date: 5-31-91 Time: 9^{00}	Date: 5-31-91 Time: 12^{00}	
Final: 75.6389 Tare:	75.6382	75.6385	AVERAGE grms. 75.6390 grms.
		NET:	0.0000 mg.

3 Fraction: ~~Condensable Organics~~ # H_2O Blank 50mL

#1	#2	#3	
Date: 5-24-91 Time: 17^{30}	Date: 5-31-91 Time: 9^{00}	Date: 5-31-91 Time: 12^{00}	
Final: ~~75.2059~~ Tare:	75.2025	75.2027	AVERAGE .2026 grms. 75.2040 grms.
		NET:	0.0000 mg.

Client: GWM

Analyst:

Report #: T-1294

Test Date: 5-21-91

Kiln #1

TITRIMETRIC ANALYSIS

Norm Stack

Sample I.D./Run #	Total Sample (mls)	Aliquot mls	Normality	Titrant mls	mg
PdN	259	25	0.008557	0.105	0.00
	"	"	"	0.00	
IPA	261	"	"	~~0.9~~ 0.09	0.00
	"	"	"	~~0.8~~ 0.08	
H_2O_2	255	"	"	15.79	
"	"	"	"	15.72	43.89
"	"	"	"	15.72	
Filter	100	"	"	~~1.42~~ → Cation Exch Resin	
"	"	"	"	0.29	
"	"	"	"	0.30	0.164

COMMENTS:

ST18

Client: Gwm

Analyst:

Report #: T-1294

Test Date: 5-20-91

Filt #2 South Stack

TITRIMETRIC ANALYSIS

Sample I.D./Run #	Total Sample (mls)	Aliquot mls	Normality	Titrant mls	mg
P/N	290	25	0.008557	0.00	0.0
"	"	"	"	0.00	
IPA	242	"	"	~~1.18~~	
"	"	"	"	~~1.15~~	
"	"	"	"	1.22	
"	"	"	"	1.20	3.432
H_2O_2	364	"	"	4.97	
"	"	"	"	~~5.00~~	19.732
"	"	"	"	4.99	
Filter	100	"	"	0.18	
Filter	"	"	"	~~0.~~ 0.16	0.00

COMMENTS:

ST18

Client: GWM

Analyst: AFG

Report #: T 1294

Test Date: 5-30-91

kiLN #2

middle Stack

TITRIMETRIC ANALYSIS

Sample I.D./Run #	Total Sample (mls)	Aliquot mls	Normality	Titrant mls	m
IPA	280	25	0.008557	0.21	
"	"	"	"	~~0.24~~	
"	"	"	"	0.22	
			Blanked	0.040	0.1.
H_2O_2	355	"	"	3.70	
"	"	"	"	3.71	
			Blanked	3.675	14.
Filter extract IPA	100	"	"	0.10	
"	"	"	"	0.08	
			Blanked	0.00	
P/N	50	"	"	0.03	
"	"	"	"	0.04	
			Blanked	0.00	

COMMENTS:

ST18

Client: Gwm

Report #: T1294

Test Date: 5-29-91

Analyst: AFC

Kiln #2

GRAVIMETRIC ANALYSIS

6

Fraction: Probes and Nozzle Washings

#1	#2	#3	
Date: 5-24-91 Time: 17[30]	Date: 5-31-91 Time: 9[00]	Date: 5-31-91 Time: 12[00]	
Final: ~~75.7318~~ Tare:	75.7283	75.2287	AVERAGE 75.2285 grms. 75.7311 grms.

NET: 0.0000 mg.

Fraction: Filter Filter No:

#1	#2	#3	
Date: 5-24-91 Time: 10[00]	Date: 5-24-91 Time: 17[30]	Date: Time:	
Final: 0.5091 Tare:	0.5086		AVERAGE 0.4988 grms. 0.4988 grms.

NET: 0.0000 mg.

12

Fraction: Condensables Aliquot: 100 Total Sample: 280

#1	#2	#3	
Date: 5-24-91 Time: 17[30]	Date: 5-31-91 Time: 9[00]	Date: 5-31-91 Time: 1200	
Final: 76.9017 Tare:	76.9022	76.9023	AVERAGE 76.9022 grms. 76.9020 grms.

NET: 0.20 ~~0.0000~~ mg.

5

Fraction: ~~Condensable Organics~~ IPA BL 50 mL

#1	#2	#3	
Date: 5-24-91 Time: 17[30]	Date: 5-31-91 Time: 9[00]	Date: 5-31-91 Time: 12[00]	
Final: 76.9007 Tare:	76.8983	76.8978	AVERAGE 76.8981 grms. 76.8989 grms.

NET: 0.0000 mg.

Client: GWM   Analyst: ____________

Report #: T-1294

Test Date: 5-20-91

Kiln #2

North Stack

TITRIMETRIC ANALYSIS

Sample I.D./Run #	Total Sample (mls)	Aliquot mls	Normality	Titrant mls	m
P/N	420	25	0.008557	0.00	0.
"	"	"	"	0.00	
IPA	278	25	0.008557	0.63	1.75
"	"	"	"	0.64	
H_2O_2	320	25	"	~~7.01~~	
"	"	"	"	6.82	23.8
"	"	"	"	6.84	
Filter	100	25	"	0.20	0.02
"	"	"	"	0.19	

COMMENTS:

ST18

Client: Gum

Analyst:

Report #: T-1294

Test Date: 5-20 - 5-21-91

TITRIMETRIC ANALYSIS

Sample I.D./Run #	Total Sample (mls)	Aliquot mls	Normality	Titrant mls
IPA Blank	100 ml	25 uL	0.008557	0.17
"	"	"	"	0.18
H_2O_2 Blank	"	"	"	0.03
"	"	"	"	0.03

COMMENTS:

ST18

APPENDIX C

VOLUME FLOW DATA

SOUTH COAST ENVIRONMENTAL COMPANY
1915 MCKINLEY AVENUE, SUITE E
LA VERNE, CA 91750
(714) 596-6540

PARTICULATE SOURCE TEST CALCULATION SPREADSHEET

COMPANY: GREAT WESTERN MALTING
UNIT: KILN #1; SOUTH STACK
DATE: 5-21-91
PROJECT #: T-1294

AVERAGE STACK TEMP (Ts)......	81.9 dF		WATER VAPOR CONDENSED (Vl).	29.6
STACK AREA..................	21.67 FT^2		GAS VOLUME (Vm)...........	40.76
BAROMETRIC PRESSURE (Pb).....	29.8 "Hg		METER TEMP (Tm)...........	70.6
STACK PRESSURE (Ps)..........	29.77 "Hg		ORIFACE PRESSURE (dH)......	1.19
PITOT CORRECTION FACTOR......	0.84		DRY GAS METER COEF (Y).....	1.0009
SAMPLING TIME................	72 MIN		% CO2.....................	0.1
NOZZLE DIA (INCHES).	0.35	0.000667 FT^2	% O2......................	20.9
SQUARE ROOT dP...............	0.7487 "H20		STANDARD TEMP (Tstd).......	60

1. CORRECTED GAS VOLUME METERED (Vm,STD)
[(Tstd+460)/29.92]*Vm*Y*(Pb+(dH/13.6))/(Tm+460)...... 39.94 DSCF

2. VOLUME OF WATER CONDENSED (Vw,STD)
(.0464)*(Vl).. 1.37 SCF

3. MOISTURE CONTENT IN GAS STREAM (Bws)
(Vw,STD)/(Vw,STD+Vm,STD)............................ 0.033

4. DRY MOLECULAR WIEGHT OF STACK GAS (MWd)
[0.44(%CO2)+0.32(%O2)+.28(100-%CO2-%O2)]............ 28.85

5. WET MOLECULAR WIEGHT OF STACK GAS (MWs)
MWd*(1-BWs)+(18*BWs)................................ 28.49

6. STACK GAS VELOCITY (Vs)
85.49*Cp*SQRT dP*SQRT[(Ts+460)/(Ps*MWs)]............ 42.98 FPS

7. STACK GAS FLOW RATE (ACFM)
Vs*STACK AREA*60...................................55876.25 ACFM

8. STACK GAS FLOW RATE AT STANDARD CONDITIONS (DSCFM)
60*(1-BWs)*Vs*As*((Tstd+460)/Ts+460))*(Ps/29.92).....51575.66 DSCFM

SOUTH COAST ENVIRONMENTAL COMPANY
1915 MCKINLEY AVENUE, SUITE E
LA VERNE, CA 91750
(714) 596-6540

PARTICULATE SOURCE TEST CALCULATION SPREADSHEET

COMPANY: GREAT WESTERN MALTING
UNIT: KILN #1; MIDDLE STACK
DATE: 5-21-91
PROJECT #: T-1294

AVERAGE STACK TEMP (Ts)......	84	dF	WATER VAPOR CONDENSED (Vl).	28.8
STACK AREA..................	21.67	FT^2	GAS VOLUME (Vm)...........	30.86
BAROMETRIC PRESSURE (Pb).....	29.8	"Hg	METER TEMP (Tm)...........	82.6
STACK PRESSURE (Ps)..........	29.79	"Hg	ORIFACE PRESSURE (dH)......	1.076
PITOT CORRECTION FACTOR......	0.84		DRY GAS METER COEF (Y).....	1.00243
SAMPLING TIME................	72	MIN	% CO2......................	0.1
NOZZLE DIA (INCHES). 0.205	0.000229	FT^2	% O2.......................	20.9
SQUARE ROOT dP...............	0.6031	"H20	STANDARD TEMP (Tstd).......	60

1. CORRECTED GAS VOLUME METERED (Vm,STD)
[(Tstd+460)/29.92]*Vm*Y*(Pb+(dH/13.6))/(Tm+460)...... 29.61 DSCF

2. VOLUME OF WATER CONDENSED (Vw,STD)
(.0464)*(Vl).. 1.34 SCF

3. MOISTURE CONTENT IN GAS STREAM (Bws)
(Vw,STD)/(Vw,STD+Vm,STD)............................ 0.043

4. DRY MOLECULAR WIEGHT OF STACK GAS (MWd)
[0.44(%CO2)+0.32(%O2)+.28(100-%CO2-%O2)]............ 28.85

5. WET MOLECULAR WIEGHT OF STACK GAS (MWs)
MWd*(1-BWs)+(18*BWs)................................ 28.38

6. STACK GAS VELOCITY (Vs)
85.49*Cp*SQRT dP*SQRT[(Ts+460)/(Ps*MWs)]............ 34.74 FPS

7. STACK GAS FLOW RATE (ACFM)
Vs*STACK AREA*60....................................45167.56 ACFM

8. STACK GAS FLOW RATE AT STANDARD CONDITIONS (DSCFM)
60*(1-BWs)*Vs*As*((Tstd+460)/Ts+460))*(Ps/29.92).....41130.77 DSCFM

9. PERCENT ISOKINETIC SAMPLING RATE
[(Ts+460)*Vm,STD*29.92*100]/
[((Tstd+460)*Vs*TIME*An*Ps*60*(1-BWs)]............... 94.56 %

SOUTH COAST ENVIRONMENTAL COMPANY
1915 MCKINLEY AVENUE, SUITE E
LA VERNE, CA 91750
(714) 596-6540

PARTICULATE SOURCE TEST CALCULATION SPREADSHEET

COMPANY: GREAT WESTERN MALTING
UNIT: KILN #1; NORTH STACK
DATE: 5-21-91
PROJECT #: T-1294

AVERAGE STACK TEMP (Ts)......	81.6 dF	WATER VAPOR CONDENSED (Vl).	25.6
STACK AREA..................	21.67 FT^2	GAS VOLUME (Vm)............	37.08
BAROMETRIC PRESSURE (Pb).....	29.8 "Hg	METER TEMP (Tm)............	81.6
STACK PRESSURE (Ps)..........	29.78 "Hg	ORIFACE PRESSURE (dH)......	0.85
PITOT CORRECTION FACTOR......	0.84	DRY GAS METER COEF (Y).....	1.00243
SAMPLING TIME................	72 MIN	% CO2......................	0.1
NOZZLE DIA (INCHES). 0.4	0.000872 FT^2	% O2.......................	20.9
SQUARE ROOT dP...............	0.6633 "H20	STANDARD TEMP (Tstd).......	60

1. CORRECTED GAS VOLUME METERED (Vm,STD)
[(Tstd+460)/29.92]*Vm*Y*(Pb+(dH/13.6))/(Tm+460)...... 35.62 DSCF

2. VOLUME OF WATER CONDENSED (Vw,STD)
(.0464)*(Vl).. 1.19 SCF

3. MOISTURE CONTENT IN GAS STREAM (Bws)
(Vw,STD)/(Vw,STD+Vm,STD)............................ 0.032

4. DRY MOLECULAR WIEGHT OF STACK GAS (MWd)
[0.44(%CO2)+0.32(%O2)+.28(100-%CO2-%O2)]............ 28.85

5. WET MOLECULAR WIEGHT OF STACK GAS (MWs)
MWd*(1-BWs)+(18*BWs)................................ 28.50

6. STACK GAS VELOCITY (Vs)
85.49*Cp*SQRT dP*SQRT[(Ts+460)/(Ps*MWs)]............. 38.05 FPS

7. STACK GAS FLOW RATE (ACFM)
Vs*STACK AREA*60.....................................49471.57 ACFM

8. STACK GAS FLOW RATE AT STANDARD CONDITIONS (DSCFM)
60*(1-BWs)*Vs*As*((Tstd+460)/Ts+460))*(Ps/29.92).....45750.60 DSCFM

SOUTH COAST ENVIRONMENTAL COMPANY
1915 MCKINLEY AVENUE, SUITE E
LA VERNE, CA 91750
(714) 596-6540

PARTICULATE SOURCE TEST CALCULATION SPREADSHEET

COMPANY: GREAT WESTERN MALTING
UNIT: KILN #2; SOUTH STACK
DATE: 5-20-91
PROJECT #: T-1294

AVERAGE STACK TEMP (Ts)......	87.5	dF	WATER VAPOR CONDENSED (V1).	54.9
STACK AREA..................	30.875	FT^2	GAS VOLUME (Vm)............	36.89
BAROMETRIC PRESSURE (Pb).....	29.82	"Hg	METER TEMP (Tm)............	93
STACK PRESSURE (Ps)..........	29.81	"Hg	ORIFACE PRESSURE (dH)......	1.4
PITOT CORRECTION FACTOR......	0.84		DRY GAS METER COEF (Y).....	1
SAMPLING TIME................	60	MIN	% CO2......................	0.1
NOZZLE DIA (INCHES). 0.35	0.000667	FT^2	% O2.......................	20.9
SQUARE ROOT dP...............	0.5577	"H20	STANDARD TEMP (Tstd).......	60

1. CORRECTED GAS VOLUME METERED (Vm,STD)
[(Tstd+460)/29.92]*Vm*Y*(Pb+(dH/13.6))/(Tm+460)...... 34.69 DSCF

2. VOLUME OF WATER CONDENSED (Vw,STD)
(.0464)*(V1).. 2.55 SCF

3. MOISTURE CONTENT IN GAS STREAM (Bws)
(Vw,STD)/(Vw,STD+Vm,STD)............................ 0.068

4. DRY MOLECULAR WIEGHT OF STACK GAS (MWd)
[0.44(%CO2)+0.32(%O2)+.28(100-%CO2-%O2)]............ 28.85

5. WET MOLECULAR WIEGHT OF STACK GAS (MWs)
MWd*(1-BWs)+(18*BWs)................................ 28.11

6. STACK GAS VELOCITY (Vs)
85.49*Cp*SQRT dP*SQRT[(Ts+460)/(Ps*MWs)]............ 32.37 FPS

7. STACK GAS FLOW RATE (ACFM)
Vs*STACK AREA*60....................................59970.36 ACFM

8. STACK GAS FLOW RATE AT STANDARD CONDITIONS (DSCFM)
60*(1-BWs)*Vs*As*((Tstd+460)/Ts+460))*(Ps/29.92).....52866.85 DSCFM

SOUTH COAST ENVIRONMENTAL COMPANY
1915 MCKINLEY AVENUE, SUITE E
LA VERNE, CA 91750
(714) 596-6540

PARTICULATE SOURCE TEST CALCULATION SPREADSHEET

COMPANY: GREAT WESTERN MALTING
UNIT: KILN #2; MIDDLE STACK
DATE: 5-20-91
PROJECT #: T-1294

AVERAGE STACK TEMP (Ts)......	105 dF		WATER VAPOR CONDENSED (Vl).	84.4
STACK AREA..................	30.875 FT^2		GAS VOLUME (Vm)............	47.92
BAROMETRIC PRESSURE (Pb).....	29.82 "Hg		METER TEMP (Tm)............	96
STACK PRESSURE (Ps)..........	29.81 "Hg		ORIFACE PRESSURE (dH)......	2.12
PITOT CORRECTION FACTOR......	0.84		DRY GAS METER COEF (Y).....	1.0009
SAMPLING TIME................	60 MIN		% CO2......................	0.1
NOZZLE DIA (INCHES).	0.3	0.000490 FT^2	% O2.......................	20.9
SQUARE ROOT dP...............	0.5254 "H20		STANDARD TEMP (Tstd).......	60

1. CORRECTED GAS VOLUME METERED (Vm,STD)
[(Tstd+460)/29.92]*Vm*Y*(Pb+(dH/13.6))/(Tm+460)...... 44.94 DSCF

2. VOLUME OF WATER CONDENSED (Vw,STD)
(.0464)*(Vl).. 3.92 SCF

3. MOISTURE CONTENT IN GAS STREAM (Bws)
(Vw,STD)/(Vw,STD+Vm,STD)............................ 0.080

4. DRY MOLECULAR WIEGHT OF STACK GAS (MWd)
[0.44(%CO2)+0.32(%O2)+.28(100-%CO2-%O2)]............. 28.85

5. WET MOLECULAR WIEGHT OF STACK GAS (MWs)
MWd*(1-BWs)+(18*BWs)................................ 27.98

6. STACK GAS VELOCITY (Vs)
85.49*Cp*SQRT dP*SQRT[(Ts+460)/(Ps*MWs)]............. 31.05 FPS

7. STACK GAS FLOW RATE (ACFM)
Vs*STACK AREA*60.....................................57523.53 ACFM

8. STACK GAS FLOW RATE AT STANDARD CONDITIONS (DSCFM)
60*(1-BWs)*Vs*As*((Tstd+460)/Ts+460))*(Ps/29.92).....48519.42 DSCFM

9. PERCENT ISOKINETIC SAMPLING RATE
[(Ts+460)*Vm,STD*29.92*100]/
[((Tstd+460)*Vs*TIME*An*Ps*60*(1-BWs)]............... 97.15 %

SOUTH COAST ENVIRONMENTAL COMPANY
1915 MCKINLEY AVENUE, SUITE E
LA VERNE, CA 91750
(714) 596-6540

PARTICULATE SOURCE TEST CALCULATION SPREADSHEET

COMPANY: GREAT WESTERN MALTING
UNIT: KILN #2; NORTH STACK
DATE: 5-20-91
PROJECT #: T-1294

AVERAGE STACK TEMP (Ts)......	85	dF	WATER VAPOR CONDENSED (Vl).	45.4
STACK AREA...................	30.875	FT^2	GAS VOLUME (Vm)...........	31.9
BAROMETRIC PRESSURE (Pb).....	29.82	"Hg	METER TEMP (Tm)...........	86
STACK PRESSURE (Ps)..........	29.81	"Hg	ORIFACE PRESSURE (dH)......	0.85
PITOT CORRECTION FACTOR......	0.84		DRY GAS METER COEF (Y).....	1.00243
SAMPLING TIME................	60	MIN	% CO2.....................	0.1
NOZZLE DIA (INCHES). 0.4	0.000872	FT^2	% O2......................	20.9
SQUARE ROOT dP...............	0.5089	"H2O	STANDARD TEMP (Tstd).......	60

1. CORRECTED GAS VOLUME METERED (Vm,STD)
[(Tstd+460)/29.92]*Vm*Y*(Pb+(dH/13.6))/(Tm+460)...... 30.42 DSCF

2. VOLUME OF WATER CONDENSED (Vw,STD)
(.0464)*(Vl).. 2.11 SCF

3. MOISTURE CONTENT IN GAS STREAM (Bws)
(Vw,STD)/(Vw,STD+Vm,STD)............................ 0.065

4. DRY MOLECULAR WIEGHT OF STACK GAS (MWd)
[0.44(%CO2)+0.32(%O2)+.28(100-%CO2-%O2)]............ 28.85

5. WET MOLECULAR WIEGHT OF STACK GAS (MWs)
MWd*(1-BWs)+(18*BWs)................................ 28.15

6. STACK GAS VELOCITY (Vs)
85.49*Cp*SQRT dP*SQRT[(Ts+460)/(Ps*MWs)]............. 29.45 FPS

7. STACK GAS FLOW RATE (ACFM)
Vs*STACK AREA*60....................................54559.48 ACFM

8. STACK GAS FLOW RATE AT STANDARD CONDITIONS (DSCFM)
60*(1-BWs)*Vs*As*((Tstd+460)/Ts+460))*(Ps/29.92).....48505.99 DSCFM

SOUTH
COAST
ENVIRONMENTAL
COMPANY

APPENDIX D

FIELD DATA SHEETS

PAGE 1OF2

SOUTH COAST ENVIRONMENTAL COMPANY

PLANT GWM TEST TYPE SCAQMD 6.1 FIELD TEST DATA SHEET

metal Basket

KILN #1

Date 5/21/91
Test Location South Stack
Run Number 1
Stack Diameter 60X52
Operator Shannon Wilcox
Filter No.

Barometric Pressure 29.80
Static in. wg. -0.38
Probe Type/Length 3S-1
Pitot Coefficient 0.84
Meter Box No. NuTech
Nozzle No./Size 0.35

Impinger Volumes/Weights			
Contents	Final	Initial	Net
80% IPA		546.8	
H_2O		476.1	
3% H_2O_2		566.7	
3% H_2O_2		566.5	
Silica gel		717.2	
Line Wash			(63.8)
		Total	

Gas Composition			
Time	CO_2	O_2	CO
	0.1	20.902	

Leak Rate	cfm	"Hg
Initial	.005	10
Final		

Sample Point	Time	ΔP in wg	ΔH in wg	Gas Meter Volume Ft^3	Temperature °F Stack	Probe	Oven	Imp.	Gas Meter In	Gas Meter Out	Pump Vacuum in. Hg	$\sqrt{\Delta P}$	Comments
A4	11:00		1.40	273.100					63	62	4.5		Rate ~.055 cfm
A4	11:05		1.20	276.82					65	63	4.0		~12 ppm SO_2
A4	11:10		1.20	279.60					68	63	4		
A4	11:15		1.20	282.35					70	64	4		
A4	11:20		1.10	285.10					72	65	4		V_m = 40.76
A4	11:25		1.10	287.85					74	67	4		ΔP = 0.5606
A4	11:30		1.10	290.58					74	66	4		T_s = 81.9
A4	11:35		1.20	292.64					72	66	4		ΔH ~ 1.19
A4	11:40		1.20	295.55					74	67	4		T_m ~ 70.6
4	11:45		1.20	298.46					75	68	4		
4	11:50		1.20	301.33					77	69	4		
4	11:55		1.20	304.19					78	70	4		

...GE _ OF _

SOUTH COAST ENVIRONMENTAL COMPANY

PLANT GWM TEST TY... SCAQMD 6.1 FIELD TEST DATA SHEET

KILN #1

Total Bucket

(D)ate 5/21/91
(T)est Location South Stack
(R)un Number 1
(S)tack Diameter 60X52
(O)perator Shannan Wilcox
(F)ilter No.

Barometric Pressure 29.80
Static in. wg.
Probe Type/Length 3S-1
Pitot Coefficient 0.84
Meter Box No. NuTech
Nozzle No./Size 0.35

Impinger Volumes/Weights			
Contents	Final	Initial	Net
80% IPA	586.6	546.8	39.8
KO	477.1	476.1	1.0
3% H_2O_2	583.9	566.7	17.2
3% H_2O_2	576.2	566.5	9.7
Silica Gel	732.9	717.2	15.7
Line Wash			(83.8)
		Total	79.6

Gas Composition			
Time	CO_2	O_2	CO
	0.1	20.902	

Leak Rate	cfm	"Hg
Initial	.005	10
Final	.014	5

(S)ample Point	Time	ΔP in wg	ΔH in wg	Gas Meter Volume Ft^3	Temperature °F Stack	Probe	Oven	Imp.	Gas Meter In	Gas Meter Out	Pump Vacuum in. Hg	$\sqrt{\Delta P}$	Comments
B4	12:00		1.20	307.05					79	71	4		
B4	12:05		1.20	309.89					80	72	4		
B4	12:10		1.20	312.73					80	72	4		
B4	12:12		1.20	313.860					80	72	4		
									80	72	4		

SOUTH COAST ENVIRONMENTAL COMPANY

SOUTH COAST ENVIRONMENTAL COMPANY
1915 MCKINLEY AVENUE
SUITE E
LA VERNE, CA 91750
(714) 596-6540

FILE REF: ST12

Kiln #1 - South Stack

SAMPLE POINT LOCATION DATA SHEET

FACILITY: GWM
PROJECT #: T-1294
DATE: 5-21-91
STACK DIMENSIONS: L= 60
W= 52
H=
UPSTREAM DIST./
EQUIVALENT DIAMETERS 3
DOWNSTREAM DIST./
EQUIVALENT DIAMETERS 2
NO. OF SAMPLING POINTS
SAMPLING PORT DIMENSIONS:
DIA.=
PROTRUSION DIST.= 2

Static -.38

SAMPLE POINT	% OF STACK DIAMETER A Td/ΔP	B Td/ΔP	C Td/ΔP	DISTANCE FROM STACK WALL (IN.)	DISTANCE FROM SAMPLE PORT (IN.)
1	81.5/.86	81.8/.92	80.7/.88	3.3	
2	81.8/.76	81.8/.65	80.7/.50	9.8	
3	81.6/.70	82.2/.22	81.8/.30	16.3	
4	82.7/.77	82.0/.35	81.6/.20	22.8	
5	82.5/.84	81.8/.36	81.6/.25	29.3	
6	82.7/.90	82.0/.40	81.6/.31	35.8	
7	82.7/.95	82.4/.49	81.8/.37	42.3	
8	82.5/.96	82.4/.83	81.5/.32	48.8	
		ΔP=0.5606	Td =	81.9	

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Suite E
La Verne, CA 91750
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SOUTH COAST ENVIRONMENTAL COMPANY

PLANT 6.W.M. TEST TYPE METH. 5.2/6.1 FIELD TEST DATA SHEET

Impinger TRAIN #2

Kiln #1

Date 5/21/91

Test Location MIDDLE STK.

Run Number #1 'A'

Stack Diameter

Operator RPL

Filter No. —

Barometric Pressure 29.80

Static In. wg. -0.28

Probe Type/Length 6' Quartz

Pitot Coefficient 0.84

Meter Box No. ANDY

Nozzle No./Size 0.205

Impinger Volumes/Weights

Contents	Final	Initial	Net
80% IPA	617.6	552.3	65.3
KO	489.6	486.0	3.6
3% H2O2	572.8	557.0	15.8
3% H2O2	563.3	554.5	8.8
Silica Gel	~~802.4~~ 815.9	802.9	13.0
Line wash			(77.7)
		Total	28.8

Gas Composition

Time	CO_2	O_2	CO

Leak Rate	cfm	"Hg
Initial	0.00	15"
Final	0.00	15"

Sample Point	Time	ΔP In wg	ΔH In wg	Gas Meter Volume Ft^3	Temperature °F Stack	Probe	Oven	Imp.	Gas Meter In	Gas Meter Out	Pump Vacuum In. Hg	$\sqrt{\Delta P}$	Comments
8	11:00	1.0	2.37	705.83	86	192	186		73	64	5"		DRAEGER = 11 ppm SO_2
7	03	0.83	1.99	708.20	85	194	187		80	65	5"		
6	11:06	0.76	1.83	710.45	85	195	188		84	66	4"		
5	09	0.72	1.74	712.61	85	197	194		87	68	4"		Vm = 30.86
4	11:12	0.75	1.81		85	196	202		84	70	4"		T's = .84
3	15	0.74	1.80	716.82	86	198	196		91	71	4"		ΔP = 0.3637 0.6031
2	11:18	0.85	2.07	718.94	85	195	198		92	72	4"		Tm = 82.6
1	21	0.85	2.07		85	194	200		92	72	4"		ΔH = 1.076
	11:24			723.28									

SOUTH COAST ENVIRONMENTAL COMPANY

PLANT 6.W.M. TEST TYPE 5.2/6.1 FIELD TEST DATA SHEET

ate 5/21/91
est Location MIDDLE STK
un Number 1'B'
tack Diameter
erator RPL
lter No.

Barometric Pressure
Static in. wg.
Probe Type/Length 6' Quartz
Pitot Coefficient 0.84
Meter Box No. ANDY
Nozzle No./Size 0.205

Impinger Volumes/Weights			
Contents	Final	Initial	Net
		Total	

Gas Composition			
Time	CO_2	O_2	CO

Leak Rate	cfm	"Hg
Initial		
Final		

Sample Point	Time	ΔP in wg	ΔH in wg	Gas Meter Volume Ft^3	Temperature °F Stack	Probe	Oven	Imp.	Gas Meter In	Gas Meter Out	Pump Vacuum in. Hg	$\sqrt{\Delta P}$	Comments
8	11:26	0.35	0.85	723.28	84	197	202		89	74	3"		
7	:29	0.45	1.10	724.55	82	198	201		92	74	3"		
6	11:32	0.55	1.36	725.82	79	196	199		93	75	3"		
5	35	0.60	1.48	727.36	80	199	203		94	76	3"		
4	11:38	0.52	1.28	729.09	81	200	203		95	72	3"		
3	:41	0.45	1.11	730.82	82	197	200		97	77	3"		
2	11:44	0.35	0.86	732.25	84	198	204		97	78	3"		
1	:47	0.35	0.86	733.10	85	195	200		97	77	3"		
	11:50			733.87									

SOUTH COAST ENVIRONMENTAL COMPANY

PLANT 6.W.M TEST TY 5-2/6.1 FIELD TEST DATA SHEET

ate 5/21/91
est Location Middle stk
un Number #1 C
tack Diameter
perator RPL
lter No.

Barometric Pressure
Static in. wg.
Probe Type/Length 6' Quartz
Pitot Coefficient 0.84
Meter Box No. Andy
Nozzle No./Size 0.205

Impinger Volumes/Weights			
Contents	Final	Initial	Net
		Total	

Gas Composition			
Time	CO_2	O_2	CO

Leak Rate	cfm	"Hg
Initial		
Final	0.00	15"

Sample Point	Time	ΔP in wg	ΔH in wg	Gas Meter Volume Ft^3	Temperature °F Stack	Probe	Oven	Imp.	Gas Meter In	Gas Meter Out	Pump Vacuum in. Hg	$\sqrt{\Delta P}$	Comments
8		0.00	0.00	733.87									
7		0.00	0.00								0		
6		0.00	0.00								0		
5		0.00	0.00								0		
4		0.00	0.00								0		
3	12:07	0.12	0.30	733.87	85						0		
2	12:10	0.18	0.44	734.88	84				99	81	1"		
1	12:13	0.20	0.50	735.8	84				100	83	1"		
	12:16			736.69					100	83	1"		

SOUTH COAST ENVIRONMENTAL COMPANY

PLANT *GWM* TEST TYPE *SOx - 6.1* FIELD TEST DATA SHEET

Date *6/21/91*
Test Location *Malt house #1 - North Stack*
Run Number *1A*
Stack Diameter
Operator *KOJ*
Filter No. *N/A*

Barometric Pressure *29.80*
Static in. wg. *-0.26*
Probe Type/Length *6' Quartz*
Pitot Coefficient *0.84*
Meter Box No. [redacted] *Andy*
Nozzle No./Size *N/A*

Start = 1100 *End = 1212*

#1

Impinger Volumes/Weights			
Contents	Final	Initial	Net
80% IPA	646.7	595.2	51.5
KO	487.2	486.3	2.9
3% H_2O_2	575.7	558.1	17.6
3% H_2O_2	560.6	553.4	7.2
KO	486.1	485.5	0.6
Silica gel	816.2	804.7	11.5
[illegible]wash (65.7)		Total	25.6

Gas Composition			
Time	CO_2	O_2	CO

Leak Rate	cfm	"Hg
Initial	0.00	10
Final	0.00	6

Sample Point	Time	ΔP in wg	ΔH in wg	Gas Meter Volume Ft^3	Temperature °F Stack	Probe	Oven	Imp.	Gas Meter In	Gas Meter Out	Pump Vacuum in. Hg	$\sqrt{\Delta P}$	Comments
1	0000		0.85	976.308					65	65	4		
2	0005		0.85	979.26					65	65	4		Rate ≈ 0.55 cfm
3	0010		0.85	981.69					65	67	4		SOx Dräger ≈ 17 ppm
4	0015		0.85	984.37					66	68	4		
5	0020		0.85	986.91					67	70	4		V_m = 37.08
6	0025		0.85	989.01					67	71	4		T_s = 81.6
7	0030		0.85	991.93					68	70	4		ΔP = 0.44
8	0035		0.85	994.50					68	71	4		T_m ≈ 69.3
9	0040		0.85	997.05					68	72	4		ΔH ≈ 0.85
10	0045		0.85	999.08					69	73	4		
11	0050		0.85	001.52					69	73	4		
12	0055		0.85	003.99					69	73	4		

SOUTH COAST ENVIRONMENTAL COMPANY

PLANT GWM TEST TYPE SOx -6.1 FIELD TEST DATA SHEET

ate 5/21/91
est Location Malt house #1-North Stack
un Number 1B
ack Diameter
erator KBS
lter No. N/A

Barometric Pressure 29.80
Static In. wg. -0.35
Probe Type/Length 6' Quartz
Pitot Coefficient 0.84
Meter Box No. Andy
Nozzle No./Size N/A

Impinger Volumes/Weights			
Contents	Final	Initial	Net
		Total	

Gas Composition			
Time	CO_2	O_2	CO

Leak Rate	cfm	"Hg
Initial		
Final		

ample Point	Time	ΔP In wg	ΔH In wg	Gas Meter Volume Ft^3	Temperature °F Stack	Probe	Oven	Imp.	Gas Meter In	Gas Meter Out	Pump Vacuum In. Hg	$\sqrt{\Delta P}$	Comments
13	0060		0.85	006.55									
4	0065		0.85	009.13					70	74	4		
	0072		0.85	013,388					71	75	4		
									71	75	4		

SOUTH COAST ENVIRONMENTAL COMPANY

SOUTH COAST ENVIRONMENTAL COMPANY
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SUITE E
LA VERNE, CA 91750
(714) 596-6540

FILE REF: ST12

Kiln #1 - North Stack

SAMPLE POINT LOCATION DATA SHEET

FACILITY: GWM
PROJECT #: T-1294
DATE: 5-21-91
STACK DIMENSIONS: L= 60
W= 52
H=
UPSTREAM DIST./
EQUIVALENT DIAMETERS 3.0
DOWNSTREAM DIST./
EQUIVALENT DIAMETERS 2.0
NO. OF SAMPLING POINTS
SAMPLING PORT DIMENSIONS:
DIA.=
PROTRUSION DIST.= 8

SAMPLE POINT	% OF STACK DIAMETER A Td/ΔP	B Td/ΔP	C Td/ΔP	DISTANCE FROM STACK WALL (IN.)	DISTANCE FROM SAMPLE PORT (I
1	80.6/0.61	81.6/0.67	80.6/0.59	3.3	
2	81.1/0.57	82.0/0.57	81.5/0.33	9.8	
3	81.5/0.50	81.6/0.45	81.6/0.28	16.3	
4	81.6/0.50	81.5/0.37	82.2/0.22	22.8	
5	82.0/0.47	81.6/0.45	81.6/0.39	29.3	
6	82.2/0.56	81.6/0.55	81.8/0.22	35.8	
7	82.2/0.57	81.8/0.54	81.8/0.24	42.3	
8	82.2/0.51	81.8/0.52	81.8/0.22	48.8	
	Static = -0.26			ΔP Avg 0.44	
				Tduct = 81.6	

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Suite E
La Verne, CA 91750
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SOUTH COAST ENVIRONMENTAL COMPANY

SOUTH COAST ENVIRONMENTAL COMPANY
1915 MCKINLEY AVENUE
SUITE E
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(714) 596-6540

FILE REF: ST12

Kiln #1 middle stack

SAMPLE POINT LOCATION DATA SHEET

FACILITY: Greatwestern
PROJECT #: T-1294
DATE: 5-21-91
STACK DIMENSIONS: L= 60"
W= 52"
~~H=~~ Area 21.67
UPSTREAM DIST./
EQUIVALENT DIAMETERS 3.0
DOWNSTREAM DIST./
EQUIVALENT DIAMETERS 1.0
NO. OF SAMPLING POINTS 3 ports
SAMPLING PORT DIMENSIONS:
DIA.=
PROTRUSION DIST.= 8.0

No2 0.226

SAMPLE POINT	% OF STACK DIAMETER	DISTANCE FROM STACK WALL (IN.)	DISTANCE FROM SAMPLE PORT (IN.)
1		~~9.75~~ 3.25	11.25
2		9.75	17.75
3		16.3	24.3
4		~~8~~ 22.8	30.8
5		29.3	37.3
6		35.8	43.8
7		42.3	50.3
8		48.8	56.8

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SOUTH COAST ENVIRONMENTAL COMPANY

PLANT GWM TEST TYPE SCAQMD FIELD TEST DATA SHEET

Kiln #2

...te 5-20-91
...st Location Stack #S
... Number 1
...ck Diameter 57 x 78
...rator Shawna
...ter No. Dmistr

Barometric Pressure 29.82
Static in. wg. -0.150
Probe Type/Length 3
Pitot Coefficient 0.84
Meter Box No. AirTech AV
Nozzle No./Size 0.35

Impinger Volumes/Weights			
Contents	Final	Initial	Net
80% IPA	608.2	559.1	49.1
KO	482.0	477.9	4.1
3% H_2O_2	608.7	590.9	17.8
5% H_2O_2	577.7	566.1	11.6
KO	483.3	482.8	0.5
Silica Gel	846.4	828.8	17.6
Line wash - 45.8 (#1)		Total	54.9

Gas Composition			
Time	CO_2	O_2	CO
	0.1	20.9	

Leak Rate	cfm	"Hg
Initial	0.006	10
Final	0.014	5

Sample Point	Time	ΔP in wg	ΔH in wg	Gas Meter Volume Ft^3	Stack °F	Probe °F	Oven °F	Imp. °F	Gas Meter In °F	Gas Meter Out °F	Pump Vacuum in. Hg	$\sqrt{\Delta P}$	Comments
4	1222	–	1.40	219.00	–	–	–	–	86	87	5		
	1227		1.40	221.85	–	–			87	87	5		
	1232		1.40	224.97					89	87	5		
	1237		1.40	228.06					91	87	5		V_m = 36.89
	12:42		1.40	231.16					93	88	5		T_d = 87.5
	12:47		~~1.35~~ 1.40	234.26					94	89	5		ΔP = 0.311
	12:52		1.40	237.33					96	90	5		T_m = 93
	12:57		1.40	240.41					97	90	5		ΔH = 1.40
	1:02		1.40	243.50					98	92	5		
	1:07		1.40	246.57					100	93	5		
	1:12		1.40	249.65					101	94	5		
	1:17		1.40	252.74					103	95	5		
	1:22		1.40	[illegible]							5		[illegible] 50

SOUTH COAST ENVIRONMENTAL COMPANY
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SUITE E
LA VERNE, CA 91750
(714) 596-6540

SOUTH COAST ENVIRONMENTAL COMPANY

FILE REF: ST12

SAMPLE POINT LOCATION DATA SHEET

FACILITY: GWM

PROJECT #: T-1294

DATE: 5-20-91

STACK DIMENSIONS: L=

W=

H=

UPSTREAM DIST./
EQUIVALENT DIAMETERS

DOWNSTREAM DIST./
EQUIVALENT DIAMETERS

NO. OF SAMPLING POINTS

SAMPLING PORT DIMENSIONS:

DIA.=

PROTRUSION DIST.=

South Stack Kiln #2

static -.15

SAMPLE POINT	% OF STACK DIAMETER A Td/ΔP	B Td/ΔP	C Td/ΔP	DISTANCE FROM STACK WALL (IN.)		DISTANCE FROM SAMPLE PORT (IN.)	
1	85.8/.33	88.5/.26	88.5/.35	4.9	3.6	12.9	11.6
2	85.6/.30	87.8/.30	88.8/.40	14.6	10.7	22.6	18.7
3	85.4/.30	87.8/.26	89.2/.35	24.4	17.8	32.4	25.8
4	85.4/.30	87.8/.23	89.4/.34	34.1	24.9	42.1	32.9
5	84.7/.33	87.8/.23	89.6/.28	43.9	32.1	51.9	40.1
6	85.4/.39	87.9/.25	89.6/.29	53.6	39.2	61.6	47.2
7	85.4/.45	87.9/.26	89.6/.29	63.4	46.3	71.4	53.3
8	85.6/.45	87.9/.30	89.4/.28	73.1	53.4	81.4	60.4

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Suite E
La Verne, CA 91750
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SOUTH COAST ENVIRONMENTAL COMPANY

PLANT G.W.M. TEST TYPE 5.2/6.1 FIELD TEST DATA SHEET

RUN #2

Date 5-20-91
Test Location middle stack
Run Number #2 A'
Stack Diameter
Operator RAL
Filter No. VI

Barometric Pressure 29.82
Static in. wg. -0.172
Probe Type/Length 6 Quartz
Pitot Coefficient 0.84
Meter Box No. Andy
Nozzle No./Size 0.30

Contents	Final	Initial	Net
1 DDW	653.4	574.55	78.85
2 KO	489.3	480.93	8.37
3 H_2O_2	619.1	578.94	40.16
4 H_2O_2	591.4	577.28	14.12
5 KO	463.2	463.13	0.1
6 Silica	802.9	766.52	36.38
Line Wash	93.6 (#2)	Total	84.4

Gas Composition Time	CO_2	O_2	CO

Leak Rate	cfm	"Hg
Initial	0.00	27"
Final	0.000	15

North Port

Sample Point	Time	ΔP in wg	ΔH in wg	Gas Meter Volume Ft^3	Stack °F	Probe °F	Oven °F	Imp. °F	Gas Meter In °F	Gas Meter Out °F	Pump Vacuum in. Hg	$\sqrt{\Delta P}$	Comments
8	12:25	0.30	2.32	628.73	86	190	200		92	79	5"		
7		0.25	1.92	630.70	87	195	202		93	81	5"		
6	30	0.26	2.01	632.68	89	196	203		96	83	5"		V_m = 47.92
5		0.25	1.93	634.75	92	197	205		96	84	5"		T_s = ~~100~~ 105
4	35	0.25	1.93	636.95	95	194	203		99	87	5"		T_m = 76
3		0.27	2.09	639.40	96	190	201		103	89	5"		ΔP = 0.276
2	40	0.28	2.14	640.50	102	188	200		103	85	5"		ΔH = 2.12
1		0.29	2.21	642.57	103	191	205		103	85	5"		
	45			644.61									

SOUTH COAST ENVIRONMENTAL COMPANY

PLANT 6.U.M. TEST TYPE 5.2/6.1 Kiln #2

FIELD TEST DATA SHEET

Date 5-20-91
Test Location MIDDLE STK
Run Number #1 'B'
Stack Diameter
Operator RPL
Filter No.

Barometric Pressure 29.82
Static in. wg.
Probe Type/Length 6' Quartz
Pitot Coefficient 0.84
Meter Box No. Ams9
Nozzle No./Size 0.30

Impinger Volumes/Weights			
Contents	Final	Initial	Net
		Total	

Gas Composition			
Time	CO_2	O_2	CO
			/

Leak Rate	cfm	"Hg
Initial		
Final		

Sample Point	Time	ΔP in wg	ΔH in wg	Gas Meter Volume Ft^3	Temperature °F Stack	Probe	Oven	Imp.	Gas Meter In	Gas Meter Out	Pump Vacuum in. Hg	$\sqrt{\Delta P}$	Comments
8	12:50	0.20	1.51	644.61	109	195	205		98	86	5"		
7		0.20	1.53	646.9	~~110~~ 105	197	202		109	87	5"		
6	12:55	0.24	1.84	648.45	105	199	205		109	87	5"		
5		0.24	1.84	650.25	105	201	206		109	87	5"		
4	13:00	0.23	1.75	652.20	105	204	207		105	84	5"		
3		0.23	1.76	653.95	106	205	206		107	89	5"		
2	13:05	0.255	1.95	655.75	106	203	207		108	90	5"		
1		0.255	1.95	657.81	106	200	204		108	90	5"		
	13:10			659.55									

SOUTH COAST ENVIRONMENTAL COMPANY

PLANT 6.W.M TEST TYPE 5.2/6.1 FIELD TEST DATA SHEET

Kiln #2

te 5/20/91

st Location Middle stk

n Number #1S

ack Diameter

erator RPL

ter No.

Barometric Pressure 29.82

Static in. wg.

Probe Type/Length 6' Quartz

Pitot Coefficient 0.84

Meter Box No. Andy

Nozzle No./Size 0.30

Impinger Volumes/Weights			
Contents	Final	Initial	Net
		Total	

Gas Composition			
Time	CO_2	O_2	CO

Leak Rate	cfm	"Hg
Initial		
Final		

Sample Point	Time	ΔP in wg	ΔH in wg	Gas Meter Volume Ft^3	Temperature °F Stack	Probe	Oven	Imp.	Gas Meter In	Gas Meter Out	Pump Vacuum in. Hg	$\sqrt{\Delta P}$	Comments
8	13:14	0.245	1.84	659.55	112		200		101	91	7"		
7		0.26	1.96	662.21	114				105	92	7"		
6	13:19	0.305	2.30	664.22	115		205		106	92	7"		
5		0.31	2.33	664.88	115				106	92	7"		
4	13:24	0.35	2.63	667.55	115		204		104	93	7"		
3		0.41	3.08	670.40	115				104	93	7"		
2	13:29	0.40	3.01	672.74	115		202		103	93	7"		
1		0.40	3.01	674.91	114				103	93	7"		
	13:34			676.65			200						

SOUTH COAST ENVIRONMENTAL COMPANY

PLANT GWM TEST TYPE 6.1 - SOx FIELD TEST DATA SHEET

NORTH STACK Bucket #1

Impinger Volumes/Weights			
Contents	Final	Initial	Net
1 IPA	678.7	603.70	75.0
2 H2O	489.0	483.52	5.48
3 H2O2	601.6	580.43	20.77
4 H2O2	575.2	567.85	7.35
5 [illegible]	483.2	460.88	2.32
6 Silica	804.7	784.86	19.84
Line Wash 1 - 85.6 (#3)		Total	45.2

Gas Composition			
Time	CO_2	O_2	CO
	0.1	20.9	

Leak Rate	cfm	"Hg
Initial	0.00	10
Final	0.01	5

Date 5/20/91

Test Location Malt house #1

Run Number 1

Stack Diameter D_e = 68"

Operator KJS

Filter No.

Barometric Pressure 29.82

Static in. wg. -0.185

Probe Type/Length 6' Quartz

Pitot Coefficient 0.84

Meter Box No. Andy

Nozzle No./Size 0.40

Start = 1208 End = 1308

Sample Point	Time	ΔP in wg	ΔH in wg	Gas Meter Volume Ft^3	Temperature °F Stack	Probe	Oven	Imp.	Gas Meter In	Gas Meter Out	Pump Vacuum in. Hg	$\sqrt{\Delta P}$	Comments
1	0000		0.85	930.085					82	82	4		Rate ≈ 0.55 cfm
2	0005		0.85	932.80					82	83	4		SOx Dragger = 11 ppm
3	0010		0.85	935.42					83	84	4		
4	0015		0.85	938.23					83	85	4		V_m = 31.90
5	0020		0.85	940.73					84	86	4		T_s = 85
6	0025		0.85	943.35					84	86	4		ΔP = 0.259
7	0030		0.85	945.90					85	87	4		T_m = 86
8	0035		0.85	948.31					86	89	4		ΔH = 0.85
9	0040		0.85	951.08					86	89	4		
10	0045		0.85	953.44					87	90	4		
11	0050		0.85	956.26					87	90	4		
12	0055		0.85	958.91					87	90	4		
	0060			961.985									

SOUTH COAST ENVIRONMENTAL COMPANY

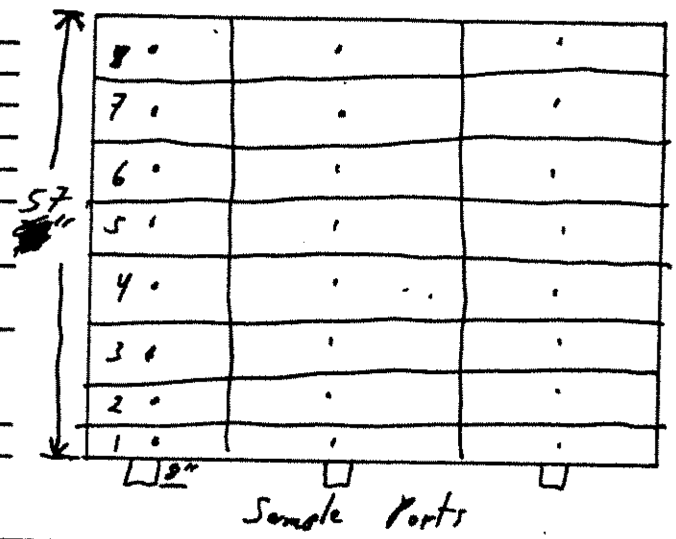
SOUTH COAST ENVIRONMENTAL COMPANY
1915 MCKINLEY AVENUE
SUITE E
LA VERNE, CA 91750
(714) 596-6540

FILE REF: ST12

Kiln #2 - North stack

SAMPLE POINT LOCATION DATA SHEET

FACILITY: GWM
PROJECT #: T1294
DATE: 5/20/91
STACK DIMENSIONS: L= 78"
W= 57"
H=
UPSTREAM DIST./
EQUIVALENT DIAMETERS 3
DOWNSTREAM DIST./
EQUIVALENT DIAMETERS 1
NO. OF SAMPLING POINTS
SAMPLING PORT DIMENSIONS:
DIA.=
PROTRUSION DIST.= 8"



SAMPLE POINT	% OF STACK DIAMETER ① T		ΔP/② T		③ T		DISTANCE FROM STACK WALL (IN.)	+8"	DISTANCE FROM SAMPLE PORT (IN	
1	84.7	0.20	85.2	0.16	85.2	0.38	4.9	3.6	12.9	11.6
2	84.5	0.20	85.2	0.15	84.9	0.42	14.6	10.7	22.6	18.7
3	84.7	0.23	85.4	0.13	84.7	0.41	24.4	17.8	32.4	25.8
4	85.4	0.24	85.4	0.14	84.2	0.38	34.1	24.9	42.1	32.9
5	85.2	0.30	85.1	0.12	84.5	0.35	43.9	32.1	51.9	40.1
6	85.6	0.35	85.2	0.16	84.7	0.32	53.6	39.2	61.6	47.2
7	85.4	0.41	84.9	0.18	84.7	~~0.2~~ 29	63.4	46.3	71.4	53.3
8	84.9	0.38	85.2	0.23	84.9	0.30	73.1	53.4	81.4	60.4

Static = ⊖0.185

1915 McKinley Ave.
Suite E
La Verne, CA 91750
714-596-6540
714-596-5619 (FAX)

SOUTH COAST ENVIRONMENTAL COMPANY
1915 MCKINLEY AVENUE
SUITE E
LA VERNE, CA 91750
(714) 596-6540

SOUTH COAST ENVIRONMENTAL COMPANY

FILE REF: ST12

SAMPLE POINT LOCATION DATA SHEET

Kiln #2

FACILITY: BWM - Kiln #2
PROJECT #: T-1294
DATE: 5-20-91
STACK DIMENSIONS: L=
W=
H=
UPSTREAM DIST./
EQUIVALENT DIAMETERS 3
DOWNSTREAM DIST./
EQUIVALENT DIAMETERS 1
NO. OF SAMPLING POINTS
SAMPLING PORT DIMENSIONS:
DIA.=
PROTRUSION DIST.=

SAMPLE POINT	% OF STACK DIAMETER	DISTANCE FROM STACK WALL (IN.)	DISTANCE FROM SAMPLE PORT (IN.)
1		~~4.9~~ 3.6	~~12.9~~ 11.6
2		~~14.6~~ 10.7	~~22.6~~ 18.7
3		~~24.4~~ 17.8	~~32.4~~ 22.8
4		~~34.1~~ 24.9	~~42.1~~ 32.9
5		~~43.9~~ 32.1	~~51.9~~ 40.1
6		~~53.6~~ 39.2	~~61.6~~ 47.2
7		~~63.4~~ 46.3	~~71.4~~ 53.3
8		~~73.1~~ 53.4	~~81.4~~ 60.4

1915 McKinley Ave.
Suite E
La Verne, CA 91750
714-596-6540
714-596-5619 (FAX)

E-8 Maxon Burner Emission Certification

September 29, 2015

Ron Heintskill
George T Hall Co.
PO Box 25269
Anaheim, CA 92825-5269
USA

SUBJECT: MAXON **KINEDIZER LE** ® BURNER EMISSIONS

REFERENCE: MAXON SALES ORDER NO. 976894

We have received your request for an emissions guarantee and a completed Emissions Survey form. Maxon Corporation's **KINEDIZER LE** ® Burner represents the finest in top quality combustion equipment. As such we can offer an amendment to our standard terms and conditions, which are attached for your reference.

For our Sales Order No. 976894, Maxon will guarantee:

NOx emissions of 30 ppm corrected to 3% O2 (0.036 lb/MMBtu).
CO emissions of 300 ppm corrected to 3% O2 (0.221 lb/MMBtu).
The Guaranteed Emissions Turndown Ratio is <u>high fire only</u>

This is not a general guarantee for all products and installations. This guarantee is made only for the equipment, operating conditions and firing rates as stated on the Emissions Survey form and the following supplemental conditions below:

- Compliance testing must be completed within six (6) months from installation, or no later than twelve (12) months from shipment of the equipment from Seller (Maxon Corporation). Failure to test within this time frame constitutes full acceptance of the equipment.
- Maxon Corporation will guarantee, following a thorough engineering analysis of the application and process, and after acceptance by the customer of the total system being supplied by Maxon Corporation, that the stated equipment will meet or exceed the emissions requirement stated on the "Emissions Survey" form. Maxon Corporation will not be responsible for product or environmental influences on system emissions. The testing agency will be required to sample at a location in the process that accurately reflects specific burner performance.

September 29, 2015

The guarantee will be substantiated, at customer's expense, by an approved independent testing agency which has the required equipment capable of measuring emissions in the customers specific application. The EPA methods found in 40CFR, Part 60, Appendix A shall be used for emissions measurement.

- NOx USEPA Method 7E
- CO USEPA Method 10
- O_2 USEPA Method 3A
- CO_2 USEPA Method 3A
- VOC USEPA Method 25A

If independent testing indicates the emissions guarantee is not being met, Maxon Corporation reserves the right, at its expense, to modify, add or delete components of the system provided.

- Maxon Corporation personnel or their sub-contractor shall have adequate access to the combustion equipment sold for the purpose of adjustment.
- Maxon Corporation retains the right to secure the services of an independent firm specializing in emission measurement.
- After Maxon system modifications are approved, and adjustments completed, the customer again will contract the independent testing agency to verify emissions.
- If the equipment fails to meet the emission guarantee and is returned with prior authorization to Maxon within this specified period, Maxon Corporation will issue a credit to your account. This credit is limited to the value of the **KINEDIZER LE** ® Burner(s), and bill of material as listed on Sales Order No.976894.
- Included in the credit will be the two emissions tests performed to substantiate this guarantee. Not included in the credit:
  1. Removal of or cost of prior equipment
  2. Installation of the equipment
  3. Re-installing or replacement equipment
  4. Loss of production
  5. Repairs to process equipment that may have been modified to suit this installation.

- This guarantee is restricted to the original installation only. Any unauthorized alterations to the system or relocation of the equipment shall void this commitment.
- Once the guaranteed emission level has been attained, Maxon Corporation is no longer held by these supplemental conditions. The transaction reverts to Maxon standard terms and conditions – 73SA (enclosed).
- Maxon equipment must be installed and operated in accordance with Maxon catalog literature.
- This emissions performance guarantee requires the use of an “air/fuel” ratio control system as supplied by Maxon Corporation. Use of other air/fuel ratio control systems, limits this guarantee to one steady-state burner condition with the process in equilibrium.

We appreciate your continued interest in Maxon combustion equipment.

Sincerely,
Maxon Corporation

Doug M Perry

Doug Perry
Burner Engineering Manager

Enclosures (73SA) – Maxon Terms & Conditions

E-9 GV Boiler Emissions Information

South Coast
Air Quality Management District
21865 Copley Drive, Diamond Bar, CA 91765-4178
(909) 396-2000 · www.aqmd.gov

August 11, 2005

Thermal Solutions
1175 Manheim Pike
Lancaster, PA 17601

Thank you for your participation in the Rule 1146.2 Administrative Certification Program. Per your request, the following models are approved under this program:

Model Nos.: EVA-250, EVA-500, EVA-750, EVA-1000, EVA-1500, EVA-2000
EVO-250, EVO-500, EVO-750, EVO-1000, EVO-1500, EVO-2000

This certification is based on the information you provided on August 2, 2005 in completing the "Rule 1146.2 Equipment Certification Request Form" and the associated source test reports as follows:

Submittal ID#:	Thermal/4
Source Test Conducted By:	BR Laboratories
Source Test Report Number(s):	R00207

Please note that the District does not endorse or warrant any specific product or manufacturer. Modification of the products listed above will void this certification. If you have any questions or require further assistance, please contact Moustafa Elsherif at (909) 396-3113 or by e-mail at melsherif@aqmd.gov.

Sincerely,

Moustafa Elsherif
Program Supervisor
Area Sources

ME:rr

cc: Laki Tisopulos
Lee Lockie

(Adopted January 9, 1998) (Amended January 7, 2005) (Amended May 5, 2006)

RULE 1146.2. EMISSIONS OF OXIDES OF NITROGEN FROM LARGE WATER HEATERS AND SMALL BOILERS AND PROCESS HEATERS

(a) Purpose and Applicability

The purpose of this rule is to reduce NOx emissions from natural gas-fired water heaters, boilers, and process heaters as defined in this rule. This rule applies to units that have a rated heat input capacity less than or equal to 2,000,000 Btu per hour. Type 1 Units as defined in this rule are typically, but not exclusively, large water heaters or smaller-sized process heaters in the above range. Type 2 Units as defined in this rule are typically, but not exclusively, small boilers or larger-sized process heaters in this range. Beginning, January 1, 2000, the provisions of this rule are applicable to manufacturers, distributors, retailers, refurbishers, installers and operators of new units. Beginning, July 1, 2002, the provisions of this rule are also applicable to operators of existing Type 2 Units.

(b) Definitions

(1) BOILER OR STEAM GENERATOR means any equipment that is fired with or is designed to be fired with natural gas, used to produce steam or to heat water, and that is not used exclusively to produce electricity for sale. Boiler or Steam Generator does not include any waste heat recovery boiler that is used to recover sensible heat from the exhaust of a combustion turbine or any unfired waste heat recovery boiler that is used to recover sensible heat from the exhaust of any combustion equipment.

(2) BTU means British thermal unit or units.

(3) CERTIFIED RETROFIT KIT means any burner and ancillary controls or blowers that have been demonstrated to comply with the provisions of this rule, on a retrofit basis, on a particular model of unit.

(4) FIRE TUBE BOILER means a BOILER in which hot gases from the combustion chamber pass through one or more tubes within the boiler.

(5) HEAT INPUT means the higher heating value of the fuel to the unit measured as BTU per hour.

(6) HEAT OUTPUT means the enthalpy of the working fluid output of the unit.

(7) INDEPENDENT TESTING LABORATORY means a testing laboratory that meets the requirements of District Rule 304, subdivision (k) and is approved by the District to conduct certification testing under the Protocol.

(8) INSTANTANEOUS WATER HEATER means a WATER HEATER with a rated heat input capacity less than or equal to 2,000,000 Btu per hour that heats water only when it flows through a heat exchanger.

(9) NOx EMISSIONS means the sum of nitrogen oxide and nitrogen dioxide in the flue gas, collectively expressed as nitrogen dioxide.

(10) POOL HEATER means a WATER HEATER designed to heat a pool, hot tub or spa.

(11) PROCESS HEATER means any equipment that is fired with or is designed to be fired with natural gas and which transfers heat from combustion gases to water or process streams. Process Heater does not include any kiln or oven used for annealing, drying, curing, baking, cooking, calcining, or vitrifying; or any unfired waste heat recovery heater that is used to recover sensible heat from the exhaust of any combustion equipment.

(12) PROTOCOL means South Coast Air Quality Management District Protocol: Nitrogen Oxides Emissions Compliance Testing for Natural Gas-Fired Water Heaters and Small Boilers.

(13) RATED HEAT INPUT CAPACITY means the gross heat input of the combustion device, as supported by required documentation and which shall be specified on a permanent rating plate.

(14) RECREATIONAL VEHICLE means any vehicle used for recreational purposes designed to include a water heater and licensed to be driven or moved on the highways of California.

(15) REFURBISHER means anyone who reconditions a Type 1 Unit or Type 2 Unit and offers the unit for resale, for use in the District.

(16) RESELLER means anyone who sells either retail, wholesale or on an individual basis Type 1 Units or Type 2 Units.

(17) RESIDENTIAL means any structure which is designed for and used exclusively as a dwelling for not more than four families, and where such equipment is used by the owner or occupant of such a dwelling.

(18) TANK TYPE WATER HEATER means a WATER HEATER with a rated heat input capacity from 75,000 Btu per hour to 2,000,000 Btu per hour

and with an integral closed vessel in which water is heated and stored for use external to the vessel.

(19) THERM means 100,000 BTU.

(20) THERMAL FLUID HEATER means a PROCESS HEATER in which a process is heated indirectly by a heated fluid other than water.

(21) TYPE 1 UNIT means any water heater, boiler or process heater with a RATED HEAT INPUT CAPACITY less than or equal to 400,000 BTU per hour excluding TANK TYPE WATER HEATERS subject to the limits of District Rule 1121.

(22) TYPE 2 UNIT means any water heater, boiler or process heater with a RATED HEAT INPUT CAPACITY greater than 400,000 BTU per hour up to and including 2,000,000 BTU per hour.

(23) UNIT means any boiler, steam generator, water heater or process heater as defined in paragraph (b)(1), (b)(3), (b)(4), (b)(8), (b)(10), (b)(11), (b)(18), (b)(20), (b)(21), (b)(22) or (b)(24).

(24) WATER HEATER means any equipment that is fired with or designed to be fired with natural gas and that is used solely to heat water for use external to the equipment.

(c) Requirements

(1) On or after January 1, 2000, no person shall manufacture for use, or offer for sale for use, in the District any new Type 2 Unit, unless the NOx emissions level is less than or equal to 30 ppm of NOx emissions (at 3% O_2, dry) or 0.037 pound NOx per million Btu of heat input and no more than 400 ppm of carbon monoxide (at 3% O_2, dry), as certified by the District according to subdivision (d).

(2) On or after January 1, 2001, no person shall manufacture for use, or offer for sale for use, in the District any new Type 1 Unit, unless the NOx emissions level is less than or equal to 40 nanograms of NOx (calculated as NO_2) per joule (93 lb per billion Btu) of heat output or 55 ppm NOx emissions (at 3% O_2, dry), as certified by the District according to subdivision (d).

(3) On or after July 1, 2002, no person shall operate in the District any unit with a rated heat input capacity greater than 1,000,000 Btu per hour but less than or equal to 2,000,000 Btu per hour manufactured prior to January 1, 1992, which does not meet the emissions limits required by paragraph

(c)(1). Alternatively, a unit may be modified or demonstrated to meet the emission limits of paragraph (c)(1) pursuant to the provisions of subdivision (e).

(4) On or after January 1, 2006, no person shall operate in the District any unit more than 15 years old, based on the original date of manufacture as specified in paragraph (c)(6), with a rated heat input capacity greater than 1,000,000 Btu per hour but less than or equal to 2,000,000 Btu per hour and manufactured on or after January 1, 1992, which does not meet the emissions limits required by paragraph (c)(1). Alternatively, a unit may be modified or demonstrated to meet the emission limits of paragraph (c)(1) pursuant to the provisions of subdivision (e).

(5) On or after January 1, 2006, no person shall operate in the District any unit more than 15 years old, based on the original date of manufacture as specified in paragraph (c)(6), with a rated heat input capacity greater than 400,000 Btu per hour but less than or equal to 1,000,000 Btu per hour manufactured prior to January 1, 2000, which does not meet the emissions limits required by paragraph (c)(1). Alternatively, a unit may be modified or demonstrated to meet the emission limits of paragraph (c)(1) pursuant to the provisions of subdivision (e).

(6) The original date of manufacture shall be determined by:

  (A) Original manufacturer's identification or rating plate permanently fixed to the equipment. If not available, then;

  (B) Invoice from manufacturer for purchase of equipment. If not available, then:

  (C) Unit is deemed to be more than 15 years old.

(7) On or after January 1, 2010, no person shall manufacture for use or offer for sale for use within the District any Type 2 unit unless the unit is certified pursuant to subdivision (d) to a NOx emission level of less than 14 nanograms of NOx (calculated as NO_2) per joule of heat output or less than or equal to 20 ppm of NOx emissions (at 3% O_2, dry).

(8) On or after January 1, 2012, no person shall manufacture for use or offer for sale for use within the District any Type 1 unit (excluding pool heaters), unless the unit is certified pursuant to subdivision (d) to a NOx emission level of less than 14 nanograms of NOx (calculated as NO_2) per joule of heat output or less than or equal to 20 ppm of NOx emissions (at 3% O_2, dry).

(9) On or after May 5, 2006, the owner or operator of any Type 2 unit shall perform maintenance in accordance with the manufacturer's schedule and specifications as identified in a manual and other written materials supplied by the manufacturer or distributor. The owner or operator shall maintain on site a copy of the manufacturer’s and/or distributor's written instructions and retain a record of the maintenance activity for a period of not less than three years.

(10) The owner or operator shall maintain on site a copy of all documents identifying the unit’s rated heat input capacity. The rated heat input capacity shall be identified by a manufacturer’s or distributor’s manual or invoice. If a unit is modified, the rated heat input capacity shall be calculated pursuant to paragraph (f)(3). The documentation of rated heat input capacity for modified units shall include a description of all modifications, the dates the unit was modified and calculation of rated heat input capacity. All documentation shall be signed by the licensed person modifying the unit.

(11) Notwithstanding the requirements in paragraph (c)(7), until December 31, 2010, any person may sell, offer for sale, or install any Type 2 units that are manufactured and purchased prior to January 1, 2010 and in compliance with paragraph (c)(1).

(12) Notwithstanding the requirements in paragraph (c)(8), until December 31, 2012, any person may sell, offer for sale, or install any Type 1 units that are manufactured and purchased prior to January 1, 2012 and in compliance with paragraph (c)(2).

(d) Certification

(1) The manufacturer shall obtain confirmation from an independent testing laboratory prior to applying for certification that, each unit model or retrofit kit complies with the applicable requirements of subdivision (c). This confirmation shall be based upon emission tests of a randomly selected unit of each model, and the Protocol shall be adhered to during the confirmation testing of all units subject to this rule.

(2) When applying for unit(s) certification, the manufacturer shall submit to the Executive Officer the following:

(A) A statement that the model is in compliance with subdivision (c). The statement shall be signed and dated, and shall attest to the accuracy of all statements;

(B) General Information

(i) Name and address of manufacturer,

(ii) Brand name, and

(iii) Model number, as it appears on the unit rating plate;

(C) A description of each model being certified; and

(D) A source test report verifying compliance with the emission limits in subdivision (c) for each model to be certified. The source test report shall be prepared by the confirming independent testing laboratory and shall contain all of the elements identified in Section 10 of the Protocol for each unit tested. The source test shall have been conducted no more than ninety (90) days prior to the date of submittal to the Executive Officer.

(3) When applying for unit certification, the manufacturer shall submit the items identified in paragraph (d)(2) no more than ninety (90) days after the date of the source test identified in subparagraph (d)(2)(D) and at least 120 days prior to the date of the proposed sale of the units.

(4) The Executive Officer shall certify a unit model which complies with the provisions of subdivision (c) and of paragraphs (d)(1), (d)(2), and (d)(3).

(5) Certification status shall be valid for three years from the date of approval by the Executive Officer. After the third year, recertification may be required according to the requirements of paragraphs (d)(1) and (d)(2).

(e) Modification (Retrofit) Provisions and Demonstration of Compliance With Emission Limits.

Any unit, may be modified or demonstrated to meet the requirements of paragraph (c)(1), (c)(2), (c)(3), (c)(4), or (c)(5) provided:

(1) The unit is certified pursuant to subdivision (d); or

(2) A certified retrofit kit has been installed; or

(3) A copy of a source test report conducted by an independent third party, demonstrating the specific unit complies with the emission limits at low and high fire, shall be maintained on-site; and

(4) The source test report clearly specifies the emissions limit of the unit in parts per million or pounds of NOx per million Btu of heat input. The

source test report must identify that the source test was conducted pursuant to a District approved protocol; and

(5) The source test report shall be maintained on-site at the facility where the unit is being operated and made available to the Executive Officer, at all times, upon request, as long as the unit is being operated. The model and serial numbers of the specified unit shall clearly be indicated on the source test report.

(f) Identification of Compliant Units

(1) Newly Manufactured Units

The manufacturer shall display the model number of the unit complying with subdivision (c) on the shipping carton and permanent rating plate. The manufacturer shall also display the certification status on the shipping carton and on the unit.

(2) Certified Retrofit Kits

The manufacturer shall display the model number of the retrofit kit and manufacturer and model of applicable units on the shipping carton and in a plainly visible portion of the retrofit kit.

(3) Modified Units

A unit with a new or modified burner shall display the new rated heat input capacity and certification status on a new permanent rating plate. The gross heat input shall be based on the maximum fuel input corrected for fuel heat content, temperature and pressure.

(g) Enforcement

The Executive Officer may periodically inspect distributors, retailers, and installers of units located in the District, and conduct such tests as are deemed necessary to ensure compliance with subdivision (c).

(h) Exemptions

(1) The provisions of this rule shall not apply to:

(A) Units used in recreational vehicles.

(B) Units subject to the limits in District Rule 1121 – Control of Nitrogen Oxides From Residential Type, Natural Gas-fired Water Heaters.

(2) The provisions of paragraphs (c)(3), (c)(4), and (c)(5) shall not apply to:

(A) Any residential unit.

(B) Units with a rated heat input capacity greater than 400,000 Btu per hour, but less than or equal to 2,000,000 Btu per hour that are demonstrated to use less than 9,000 therms during every calendar year. Compliance with the exemption limit shall be demonstrated by a calculation based on the annual fuel consumption recorded by an in line fuel meter or the annual operating hours recorded by a timer and using one of the following methods.

(i) Annual therm usage recorded by fuel meter and corrected to standard pressure; or

(ii) Amount of fuel (i.e., in thousand cubic feet of gas corrected to standard pressure) converted to therms using the higher heating value of the fuel; or

(iii) Annual therm usage calculated by multiplying the number of hours fuel is burned by the rated heat input capacity of the unit converted to therms.

(3) The NOx emission limits of paragraphs (c)(1), (c)(2), (c)(3), (c)(4) and (c)(5) of this rule shall not apply to units located at RECLAIM facilities.

(i) Progress Reports

Any person that manufacturers Type 1 units or Type 2 fire tube boilers, steam boilers producing steam pressure greater than 100 pounds per square inch or thermal fluid heaters subject to this rule shall submit to the District a report on progress towards compliance with the emission limits of paragraphs (c)(7) and (c)(8). Progress reports shall include detailed information on all burner and control technologies evaluated and emission tests. The progress reports shall be submitted to the District for the following categories of equipment by the specified date:

(1) Type 2 fire tube boilers, steam boilers producing steam pressure greater than 100 pounds per square inch and thermal fluid heaters shall be submitted to the District by January 31, 2008.

(2) Type 1 units shall be submitted to the District by January 31, 2010.

E-10 Washington Kiln VOC Source Test- 8/25/1994

VOC Emission Factor Information
August 24, 1994 Source Test Information

Introduction

Source tests for particulate emissions and volatile organic compounds (VOCs) were completed August 25, 1994 on the Great Western Malting Company barley kilning process located in Vancouver, Washington. Although compliance with emission regulations has never been in question for this process, the tests were done as part of the inventory necessary for determining the Title 5 status of facility. Great Western is working with Steve Van Ootegham of CH2M Hill to make this determination. Southwest Washington Air Pollution Control Authority (SWAPCA) was notified of the testing and a test plan was agreed on and filed with Steve Mrazek of that organization. No one from the Authority was present during the work.

Jay Hamachek, of Great Western, arranged for the tests; Herb Howell and John Durrell were the system operators. Emission testing was done over two shifts by Horizon Engineering personnel William Kroll, David Rossman, Kurt Torgerson, and Mike Wallace.

Summary of Results

Over the 16 hour process cycle, about 357,000 lb of green malt was processed. During that time, particulate emissions from the kiln totaled 72.6 pounds including the "back half" of the particulate train. Without the "back half" catch (EPA Method 5) emissions totaled 45.2 pounds of particulate. VOC, as carbon, was 23.5 pounds for the cycle.

Table 1 lists the results for the entire cycle. Table 2 is the results of the individual tests made during the cycle. Figure 1 is a plot showing particulate emissions (front half only, per EPA Method 5) from the entire process over the cycle on the test day and Figure 2 is similar, but includes the condensable material in the "back half" of the particulate sampling train. Figure 3 shows the VOC emissions over the cycle.

Table 1
Combined Test Results

August 25, 1994

Particulate (front and back halves)	
Total Emissions, pounds	72.6
Average Concentration, gr/scfd	0.00398
Particulate (front half only)	
Total Emissions, pounds	45.2
Average Concentration, gr/scfd	0.00327
VOC as Carbon Emissions	
Total Emissions, pounds	23.5
Average Concentration, ppmv	3.4
Process Information	
Cycle Time (normal) hours	16
Green Malt Processed, pounds	357,000

Great Western Malting Emissions
Fans K 1-4 VOC/TGOC as Carbon

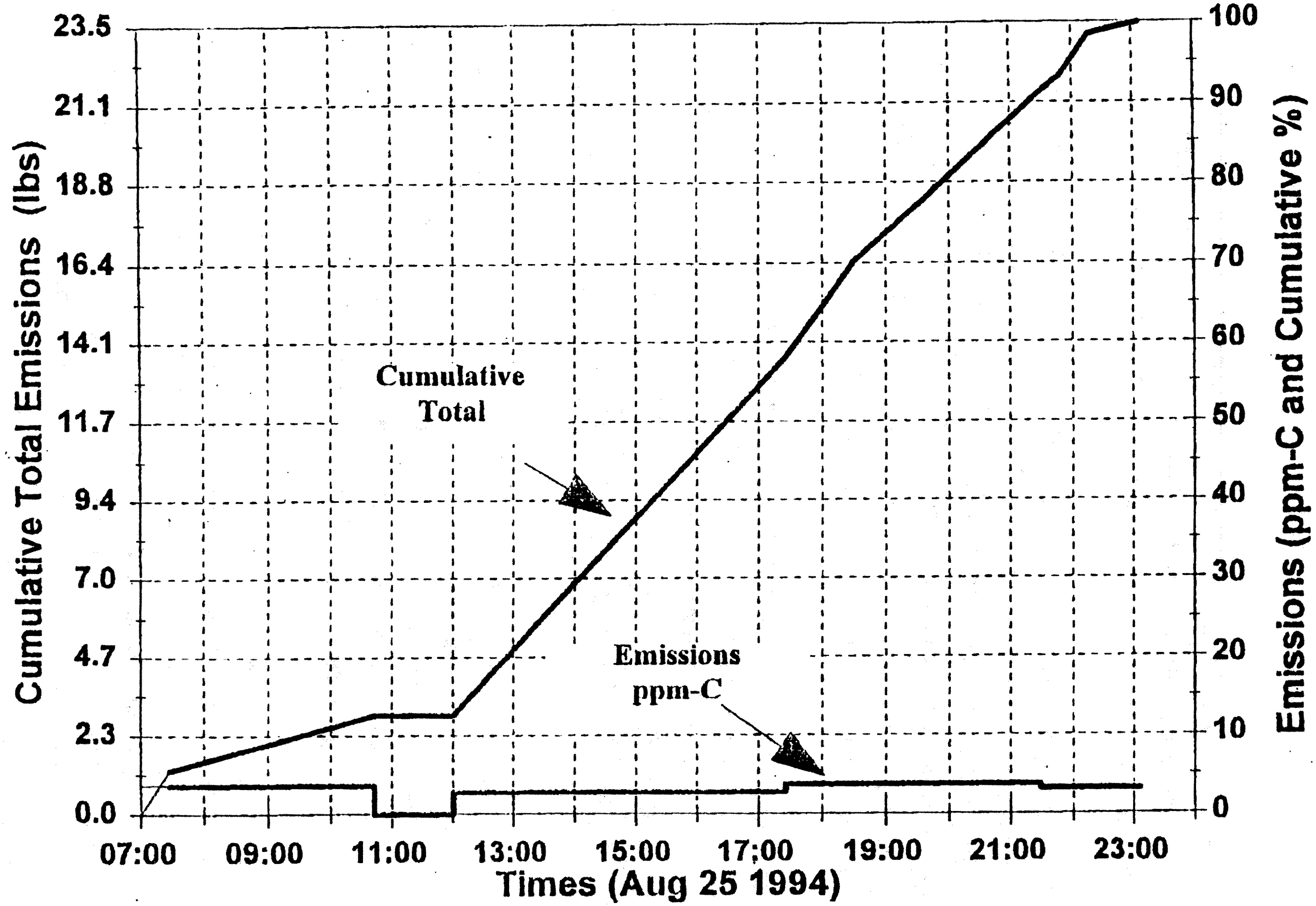


Figure 3

GREAT WESTERN MALTING, AUGUST 1994

Description of the Source

Literature on the malting process is included in the Appendix. The kiln tested uses a Saladin type compartment house, completed in 1978. Figure 4 shows the compartment house in the center. Figure 5 is a diagram of the system.

Green malt is dried in two stages on the upper and lower drying beds. Each bed is similar to a giant perforated venetian blind that supports the malt. After the specified drying period, the bed supports rotate, dropping the malt to a lower level. Every 16 hours, both beds are changed. The lower bed is unloaded to the dry malt hoppers and then closed. The upper bed then dumps its load to the lower bed and the upper bed is reloaded with green malt.

Hot air from a hot water heated coil system at ground level passes through the lower bed (or can be controlled to bypass it) then through the upper bed. Air flow through the system is induced by four variable speed exhaust fans on the roof of the building. Figure 5 shows the fans on the roof. During loading and dumping, only one fan operates; dampers on all the other fans are closed. Otherwise, all four fans are normally on, but in a programmed speed sequence.

Total drying time is about 32 hours, with the total moisture content being reduced from 48% to 4% in the two stages of 16 hours each. Temperatures reach 185 °F during the process. Normal instrumentation on the process makes chart records of the static pressure above the upper bed and a strip chart record of temperatures throughout the building. Copies of these records are in the Appendix.

On the day of the testing, sometime near the end of the loading of the upper bed before the heating was started, a part broke on one of the screw augers used to distribute the green malt. Although it delayed the process for about 1 1/4 hours (workers don't like to work in the unit when the heat is on), testing was affected very little because the delay was during the changeover between the first and second particulate tests. The delay time was treated as a zero emission period for calculation purposes.

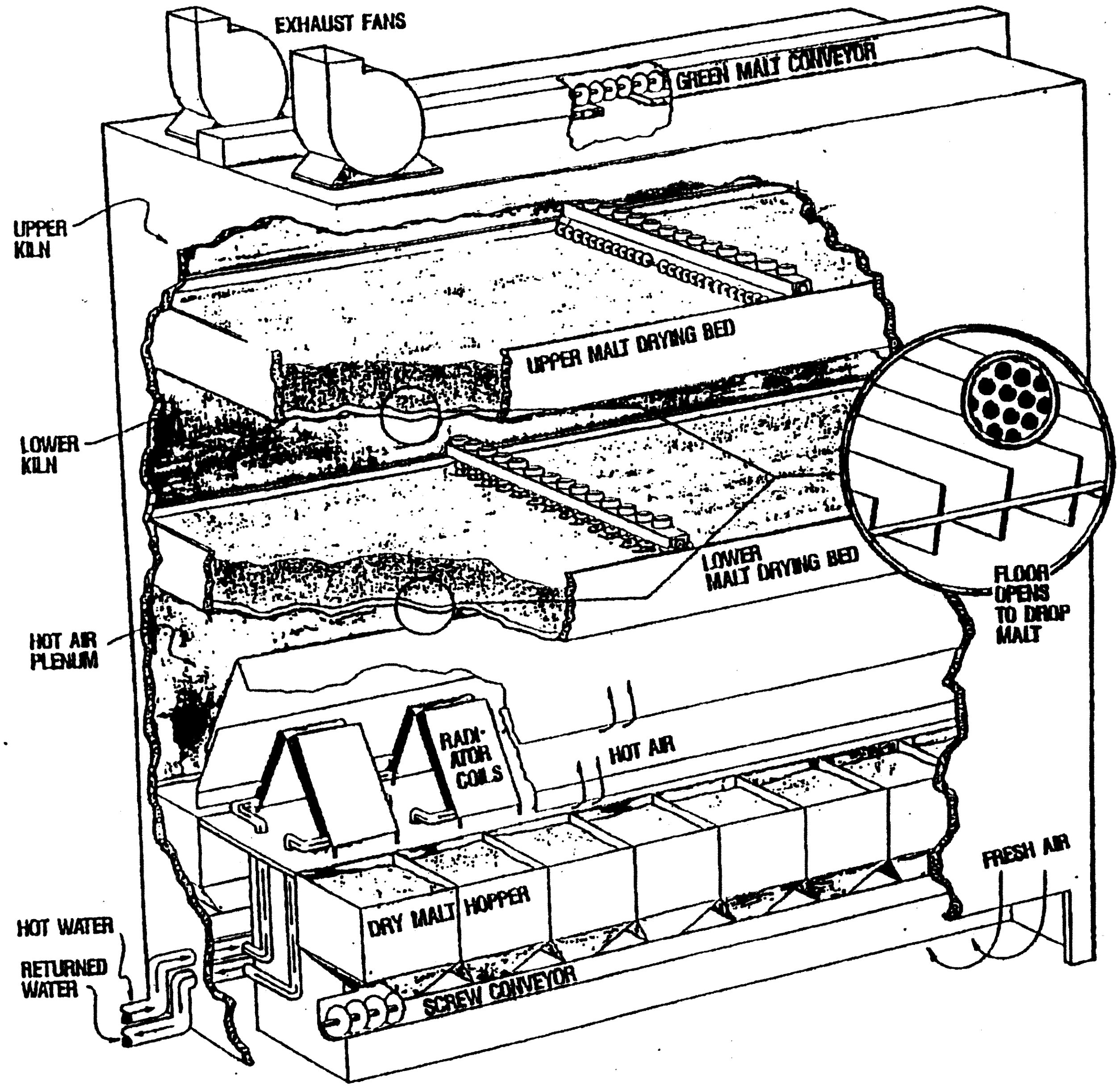


Figure 5

KILNS

- Temperatures reach 185° F.
- Moisture content is lowered from 48.0% to 4.0%
- Total drying time is 36 hours

GREAT WESTERN MALTING, AUGUST 1994

E-11 Ventura County APCD Natural Gas Emission Factors

Name	Natural Gas-Fired External Combustion		
Applicability	Use this spreadsheet for Natural Gas-Fired External Combustion (Boilers, heaters, flares). Entries required in yellow areas, output in grey areas.		
Author or updater	Matthew Cegielski	*Last Update*	March 10, 2015
Facility:			
ID#:			
Project #:			

Inputs	Rate MMscf /hr	Rate MMscf /yr	Formula
<10 MMBTU/hr	1.00E+00	100	Choose one of the MMBtu ratings and supply the necessary rate. Emissions are calculated by the multiplication of the Fuel Rates and Emission Factors.
10-100 MMBTU/hr	1.00E+00	100	
> 100 MMBTU/hr	1.00E+00	100	
Flare	1.00E+00	100	

Substances	CAS#	<10 MMBTU/hr Emission Factor lbs/ MMscf	LB/HR	LB/YR	10-100 MMBTU/hr Emission Factor lbs/ MMscf	LB/HR	LB/YR	>100 MMBTU/hr Emission Factor lbs/ MMscf	LB/HR	LB/YR	Flare Emission Factor lbs/ MMscf	LB/HR	LB/YR
Acetaldehyde	**75070**	4.30E-03	4.30E-03	4.30E-01	3.10E-03	3.10E-03	3.10E-01	9.00E-04	9.00E-04	9.00E-02	4.30E-02	4.30E-02	4.30E+00
Acrolein	**107028**	2.70E-03	2.70E-03	2.70E-01	2.70E-03	2.70E-03	2.70E-01	8.00E-04	8.00E-04	8.00E-02	1.00E-02	1.00E-02	1.00E+00
Benzene	**71432**	8.00E-03	8.00E-03	8.00E-01	5.80E-03	5.80E-03	5.80E-01	1.70E-03	1.70E-03	1.70E-01	1.59E-01	1.59E-01	1.59E+01
Ethyl Benzene	**100414**	9.50E-03	9.50E-03	9.50E-01	6.90E-03	6.90E-03	6.90E-01	2.00E-03	2.00E-03	2.00E-01	1.44E+00	1.44E+00	1.44E+02
Formaldehyde	**50000**	1.70E-02	1.70E-02	1.70E+00	1.23E-02	1.23E-02	1.23E+00	3.60E-03	3.60E-03	3.60E-01	1.17E+00	1.17E+00	1.17E+02
Hexane	**110543**	6.30E-03	6.30E-03	6.30E-01	4.60E-03	4.60E-03	4.60E-01	1.30E-03	1.30E-03	1.30E-01	2.90E-02	2.90E-02	2.90E+00
Naphthalene	**91203**	3.00E-04	3.00E-04	3.00E-02	3.00E-04	3.00E-04	3.00E-02	3.00E-04	3.00E-04	3.00E-02	1.10E-02	1.10E-02	1.10E+00
PAH's	**1151**	1.00E-04	1.00E-04	1.00E-02	1.00E-04	1.00E-04	1.00E-02	1.00E-04	1.00E-04	1.00E-02	3.00E-03	3.00E-03	3.00E-01
Propylene	**115071**	7.31E-01	7.31E-01	7.31E+01	5.30E-01	5.30E-01	5.30E+01	1.55E-02	1.55E-02	1.55E+00	2.44E+00	2.44E+00	2.44E+02
Toluene	**108883**	3.66E-02	3.66E-02	3.66E+00	2.65E-02	2.65E-02	2.65E+00	7.80E-03	7.80E-03	7.80E-01	5.80E-02	5.80E-02	5.80E+00
Xylenes	**1330207**	2.72E-02	2.72E-02	2.72E+00	1.97E-02	1.97E-02	1.97E+00	5.80E-03	5.80E-03	5.80E-01	2.90E-02	2.90E-02	2.90E+00

References:

* The emission factors are from the table, "Natural Gas Fired External Combustion Equipment" in the May 2001 update of VCAPCD AB 2588 Combustion Emission Factors. PAHs emission factor adjusted from table values to subtract Naphthalene portion.

VENTURA COUNTY AIR POLLUTION CONTROL DISTRICT
669 County Square Drive, Ventura CA 93003 805/ 645-1401 FAX 805/ 645-1444 www.vcapcd.org

AB 2588 COMBUSTION EMISSION FACTORS

Emission factors for combustion of natural gas and diesel fuel were developed for use in AB 2588 emission inventory reports in 1990 and updated in 1991, 1992 and 1995. These factors have been updated again based on new data available from the USEPA (1) (10).

These emission factors are to be used where source testing or fuel analysis are not required by the AB 2588 Criteria and Guidelines Regulations, Appendix D. The factors are divided into external combustion sources (boilers, heaters, flares) and internal combustion sources (engines, turbines). Natural gas combustion factors are further divided into a number of sub-categories, based on equipment size and type.

If better source specific data such as manufacturer's data, source tests, or fuel analysis is available, it should be used rather than these emission factors.

Natural Gas Combustion Factors

Natural gas combustion factors were developed for listed substances identified by the California Air Resources Board (CARB) as significant components of natural gas combustion emissions (2) and for some federal HAPs.

In the past, the VCAPCD has included emission factors for natural gas fired internal combustion equipment in this document. In 2000, the USEPA published air toxics emission factors for natural gas fired turbines and engines. For natural gas fired internal combustion equipment, the emission factors from the USEPA publication AP-42 (1) should be used.

For natural gas fired turbines, emission factors from Table 3.1-3 of AP-42, dated April 2000 should be used. For natural gas fired internal combustion engines, emission factors from Tables 3.2-1, 3.2-2, and 3.2-3 of AP-42, dated August 2000, as applicable, should be used.

Natural Gas Fired External Combustion Equipment

	<10 MMBTUh	10-100 MMBTUh	>100 MMBTUh	flare
Pollutant	Emissions (lb/MMcf)			
benzene	0.0080	0.0058	0.0017	0.159
formaldehyde	0.0170	0.0123	0.0036	1.169
PAH's (including naphthalene)	0.0004	0.0004	0.0004	0.014
naphthalene	0.0003	0.0003	0.0003	0.011
acetaldehyde	0.0043	0.0031	0.0009	0.043
acrolein	0.0027	0.0027	0.0008	0.010
propylene	0.7310	0.5300	0.01553	2.440
toluene	0.0366	0.0265	0.0078	0.058
xylenes	0.0272	0.0197	0.0058	0.029
ethyl benzene	0.0095	0.0069	0.0020	1.444
hexane	0.0063	0.0046	0.0013	0.029

External combustion equipment includes boilers, heaters, and steam generators.

Derivation of Factors

The emission factors for boilers, heaters, and steam generators were based on the results of source tests performed mostly on units rated at between 10 and 100 million BTU per hour. The following test data was used: benzene (3) (6) (16) (19); formaldehyde (3) (6) (19); PAH, naphthalene, toluene, xylenes, ethyl benzene (16) (19); acetaldehyde, acrolein, and propylene (19); and hexane (20).

The test results listed above were used directly to determine the emission factors for boilers, heaters, and steam generators with heat input ratings of 10-100 MMBTU/hr. For units <10 MMBTU/hr and >100 MMBTU/hr, were calculated by scaling the factors for 10-100 MMBTU/hr equipment by the ratios of their TOC emission factors (7).

For flares, the factors were developed by applying the CARB species profiles (8) to the USEPA TOC emission factor for flares (1). The internal combustion species profile was used as CARB stated that they had very little confidence in the external combustion profile, and they use only the internal combustion profile (9). Information on acrolein was not contained in the species profile used. It was therefore assumed that the ratio of acrolein to formaldehyde is the same for flares as for turbines. The PAH emission factor is from EPA (10)

Diesel Combustion Factors

Diesel (#1, #2 fuel oil) combustion factors were developed for listed substances identified by the CARB as significant components of diesel fuel combustion emissions (2) and for federal HAPs for which data was available.

Diesel Combustion Factors

	external combustion	internal combustion
Pollutant	Emissions (lb/1000 gal)	
benzene	0.0044	0.1863
formaldehyde	0.3506	1.7261
PAH's (including naphthalene)	0.0498	0.0559
naphthalene	0.0053	0.0197
acetaldehyde	0.3506	0.7833
acrolein	0.3506	0.0339
1,3-butadiene	0.0148	0.2174
chlorobenzene	0.0002	0.0002
dioxins	ND	ND
furans	ND	ND
propylene	0.0100	0.4670
hexane	0.0035	0.0269
toluene	0.0044	0.1054
xylenes	0.0016	0.0424
ethyl benzene	0.0002	0.0109
hydrogen chloride	0.1863	0.1863
arsenic	0.0016	0.0016
beryllium	ND	ND
cadmium	0.0015	0.0015
total chromium	0.0006	0.0006
hexavalent chromium	0.0001	0.0001
copper	0.0041	0.0041
lead	0.0083	0.0083
manganese	0.0031	0.0031
mercury	0.0020	0.0020
nickel	0.0039	0.0039
selenium	0.0022	0.0022
zinc	0.0224	0.0224

ND - not detected

Derivation of Factors

For external combustion equipment, formaldehyde, PAH, and naphthalene emission factors for were developed using source test data (17). Based on information from CARB it was assumed that acetaldehyde and acrolein emissions would be the same as formaldehyde (14). Emission factors for toluene, xylenes, propylene, ethyl benzene, and hexane were based on USEPA emission factors for total organic compounds and CARB species profile (8) for substances identified by CARB as significant.

For internal combustion engines, emission factors for formaldehyde, PAH's, naphthalene, and metals were based on source testing (4), (5), (6), (18). Benzene, acetaldehyde, acrolein, toluene and xylenes emission factors were based on sources (4), (5), and (18). Propylene factors were based on source tests (4) and (5). 1,3-butadiene was based on (4). Ethyl benzene and hexane emission factors were based on (18).

For all oil combustion equipment, emission factors for chlorobenzene, hydrogen chloride, and metals were based on stack testing and fuel analyses (4), (5), (6), (12), (13), (18). It was assumed that 99.9% of the chlorine contained in the fuel was converted to hydrogen chloride (15), with the remainder converted to chlorobenzene. 5% of the chromium in the fuel samples was assumed to be emitted as hexavalent chromium (15).

Dioxins (PCDD's), furans (PCDF's), and beryllium were identified as potentially significant components of diesel combustion exhaust (2). However, the only test results for diesel combustion found (11) reported "not detected" for dioxins and furans. Beryllium has not been detected in any of the diesel fuel analyses reviewed (4), (5), (6), (12), (13), (18). For emission inventory reporting purposes, facilities should report these compounds on for PRO using an emission estimation code of "99" and writing "ND" for the emissions.

References

(1) USEPA, Compilation of Air Pollutant Emission Factors, Volume I, Fifth Edition, AP-42, January 1995, and Supplement F, 2000

(2) Gary Agid, California Air Resources Board, Letter to Air Pollution Control District, September 12, 1989

(3) CARNOT, Emission Inventory Testing at Southern California Edison Company Long Beach Auxiliary Boiler, May 1990

(4) CARNOT, Emissions of Air Toxic Species: Test Conducted Under AB 2588 for the Western States Petroleum Association, May 1990

(5) South Coast Environmental, Compliance Report: Hydraulic Dredge "Ollie Riedel", Report Number T1238C, March 8, 1991

(6) ENSR Consulting and Engineering, Western States Petroleum Association, Pooled Source Report: Oil and Gas Production Combustion Sources, Fresno and Ventura Counties, California, Document Number 7230-007-700, January 1991

(7) Ventura County Air Pollution Control District, Emission Factors and Calculation Procedures, July 1985

(8) State of California Air Resources Board, Identification of Volatile Organic Compound Species Profiles, August 1991, as updated November 29, 2000, profiles 504 and 719

(9) Paul Allen, California Air Resources Board, Telephone conversation, February 1, 1990

(10) United States Environmental Protection Agency, Locating and Estimating Air Emissions From Sources of Polycyclic Organic Matter, EPA-454/R-98-014, July 1998

(11) United States Environmental Protection Agency, Toxic Air Pollutant Emission Factors-A Compilation for Selected Air Toxic Compounds and Sources, EPA-450/2-88-006a, October 1988

(12) BTC Environmental, Inc., Ventura Port District Dredge: Air Toxics Emissions Retesting, January 29, 1991

(13) Shell Western E & P, Emission Inventory Report for Ventura Avenue Field, June 11, 1990

(14) Muriel Strand, California Air Resources Board, Telephone conversation, February 6, 1990

(15) State of California Air Resources Board, Technical Guidance Document to the Criteria and Guidelines Regulation for AB 2588, August 1989

(16) Shell Western E&P, Emission Measurements for Speciated PAH's and BTXE Compounds on a Gas fired Turbine and Steam Generator, June 24-27, 1991

(17) Marine Corps Base Camp Pendleton, California: Draft Final Air Toxics Emissions Inventory Report, May 1, 1991

(18) Entropy Environmentalists, Inc., Pooled Source Testing of a Rig Diesel-Fired Internal Combustion Engine, conducted for Western States Petroleum Association, July 29-31, 1992

(19) Radian Corporation, Source Test Report for the Texaco Heater Treater, the Mobil Steam Generator, and the SWEPI Gas Turbine in the San Joaquin Valley Unified Air Pollution Control District, September 1992

(20) AIRx Testing, Emissions Testing OLS Energu Natural Gas Fired Turbine, and Two Auxiliary Boilers, Job Number 22030, April 21, 1994

Policy: Emission Factors for Toxic Air Contaminants from Miscellaneous Natural Gas Combustion Sources

Policy

When site specific or source category specific emission factors are not available, the emission factors provided in the table below shall be used to calculate Toxic Air Contaminant (TAC) emissions from miscellaneous natural gas combustion source.

TAC	Emission Factor, lb/Mscf	Emission Factor, lb/therm*
Benzene	2.1 E-6	2.06 E-7
Formaldehyde	7.5 E-5	7.35 E-6
Toluene	3.4 E-6	3.33 E-7

- Based on 1020 BTU/scf

Do not use Compilation of Air Pollutant Emission Factors (AP-42) emission factors or California Air Toxics Emission Factor (CATEF) database values for any other TAC, for the reasons discussed below.

Effective date

September 7, 2005

Background

The above emission factors are from:
- AP-42 Table 1.4-3, Emission Factors for Speciated Organic Compounds from Natural Gas Combustion; and
- only include TAC for which a reasonable number of sources have been tested using sound methodology.

AP-42 emission factors for Polycyclic Aromatic Hydrocarbons (PAHs) are not used, because:
- they are based on single tests in which the speciated PAH emissions were found to be below detection levels; and
- Ventura and San Diego Air Pollution Control Districts (APCD) do not use these factors.

AP-42 emission factors for metals are not used because:
- they are based on a small number of tests;
- they have poor EPA data quality ratings; and
- Ventura and San Diego APCD do not use these factors.

Continued on next page

Policy: Emission Factors for Toxic Air Contaminants from Miscellaneous Natural Gas Combustion Sources,
Continued

Background (continued)

CATEF database values are not used because:

- there was inadequate data; or
- the data quality was poor.

Helpful Definitions

The following is a list of associated definitions.

- ***TAC*** - Toxic Air Contaminant is an air pollutant that may cause or contribute to an increase in mortality or in serious illness or that may pose a present or potential hazard to human health.
- ***AP-42*** – Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources, developed by the U.S. Environmental Protection Agency.
- ***PAHs*** – Polycyclic aromatic hydrocarbons are chemical compounds that consist of fused aromatic rings.
- ***CATEF*** – California Air Toxics Emission Factor database contains approximately 2000 air toxics emission factors calculated from source test data collected by the California Air Resources Board.

Contact

Jane Lundquist, x4675

Document Control

Version	Revised By	Description	Date
1.1	JHL	New Policy	9/7/05
1.2	MCL	Mapping Policy	3/13/08

Approval

Name & Title	Signature	Date
Brian Bateman, Director of Engineering	**Signed by Brian Bateman**	2/28/2008

Appendix F- Malt Cleaning Aspirator and Scalper Information

KICE Industries
5500 N. Mill Heights Dr.   Wichita, KS 67219-2358
Email: sales@kice.com   Phone: 316-744-7151

Skilled Air Products and Services
to Help your Business Grow

Multi-Aspirators

Available for your industry today

Bill Kice Sr. originally developed the concept of the Kice Multi-Aspirator® in the late 1920's. The Multi-Aspirator® uses air to classify materials by size and density. By taking advantage of the differences in terminal velocities of specific products. For example, the Multi-Aspirator® is used to remove fines from plastic pellets. Today the Kice Multi-aspirator® is used extensively in grain, plastics, chemicals, pharmaceuticals and mining industries just to name a few.

Application
Testing
Sizing
Standard Features
Transitions
Custom Specs

PDF Dimension Sheets

- 4E Series
- 4F Series
- 6E Series
- 6F Series
- Air Outlet Transitions
- Return Air Plenums

Application

Lifted by the air stream

What is terminal velocity? A product’s size, density and shape affect its specific terminal velocity. In theory, a specific product will start falling at a slow rate and accelerate until it reaches its maximum speed or terminal velocity. If airflow is upward, it will oppose the gravitational force on the product, thus reducing the rate of fall. If the air velocity reaches the product’s terminal velocity, the product will “float”, and if the air velocity exceeds the product’s terminal velocity, it will lift the product. When particles within a common product stream have differing terminal velocities, some will fall and others will be lifted by the air stream. The Kice Multi-Aspirator® efficiently and accurately removes products with low terminal velocities from products with higher terminal velocities.

Back To Top

Testing

So it works right the first time

Kice performs tests on hundreds of different products each year. The Kice Testing Lab is able to simulate an actual system and accurately predict the viability of each product. Through testing, Kice is able to determine the proper loading and the proper air volume required for each product. Kice performs most of these tests free of charge. If you have a product that could possibly benefit from the use of a Kice Multi-Aspirator®, please contact Kice to set up a free test.

Back To Top

Sizing

In general, the higher the capacity the wider the Multi-Aspirator®. As the required width increases, space sometimes requires the use of Double Multi-Aspirators®. This arrangement actually uses two units placed back-to-back with a common air outlet fitting.

The other consideration is the number of passes. 4-pass and 6-pass units are standard, however 2-pass and 3-pass units are available when headroom is a major concern.

E Series Multi-Aspirators® use the standard slide angle that has been engineered and proved most efficient for over fifty years. The E Series is the most commonly used model.

F Series Multi-Aspirators® use the same, standard slide angle but have a shorter overall height than the E Series. The F Series can be used on products that have higher bulk densities and flow well.

Custom designed units, typically with steeper slide angles, are available for products with very low bulk densities that do not flow well. These are designed based on our lab tests.

Back To Top

Standard Features

Materials of Construction include mild steel painted Kice white, 304 stainless steel, polished 304 stainless steel with welds ground smooth and polished, as well as many other materials for unique applications.

Removable Front Slides allow access into the entire interior of the unit.

Support Feet secure the unit to a floor or support structure.

Stainless Steel

Magnehelic Gauges provide a reference point for air settings.

Mild Steel

Stock Inlets are flush with the top of the unit and have threaded holes for bolting inlet transitions on to the unit.

Bolt-On Access Doors on the end of each unit allow for access to the inside of the units for blow down cleaning.

Support Feet

Magnetic Gauges

Back To Top

Air Outlet Transitions

Different air outlet styles are available to fit virtually any field requirements. Turning vanes in the air outlet fittings ensure even air flow across the Multi-Aspirator®. Among these three styles there is also a Style D and Style A:A.

Style A

Style B

Style C

Back To Top

Custom Features for Every Application

Air Inlet Filters provide clean air to the Multi-Aspirator®. Commonly used in the plastics and pharmaceutical industries.

Drop Front Slides provide easy access to the interior for cleaning.

Lexan Doors with quick release clamps on the ends of the units allow visual inspection of the process.

Anti-Static packages reduce the influence of static electricity on certain products. Commonly used in the plastics industry.

Inspection Ports below the bottom slide allow the operator to retrieve samples and monitor performance.

Plexiglas windows on the air outlet manifold allow for visual inspection during operation.

Return Air Plenums allow for a ‘closed looped’ system. Typically fines are removed by a cyclone and the air is returned to the Multi-Aspirator®. This negates the need for a baghouse filter but is not highly recommend for maximum performance.

Feed Gates above the top pass help to spread product evenly across the width of the unit.

Hinged Front Units provide quick and easy access to the interior of the unit. Commonly used on products that require regular cleaning of the machine.

AR Steel or Ceramic-Lined slides increase the life of a unit that handles abrasive materials.

Back To Top

Dockage Tester

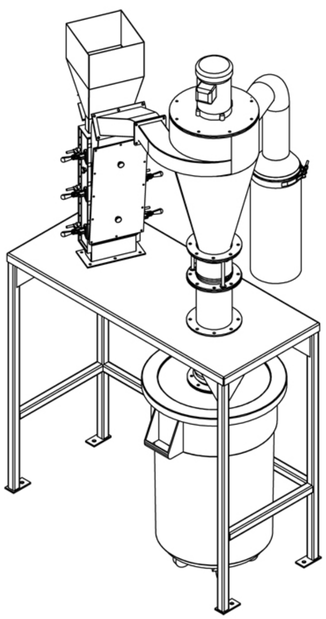
Dockage Tester
A small table top unit that is used for testing samples of products. The unit is

Portable Multi-Aspirator® System

Portable Multi-Aspirator® Systems
It is not uncommon for

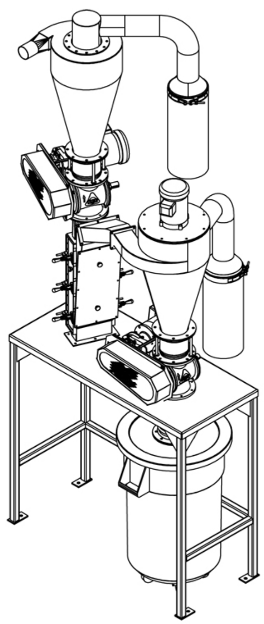
pre-wired and operated from a common 110V wall outlet. The unit weighs less than 150 pounds with a 9ft2 footprint.

customers to require a portable Multi-Aspiration® System for use in several locations. Kice can assemble many different sizes of units on to a trailer. These are commonly used by owners of multiple grain storage facilities. They are also available as rental units for a weekly charge.



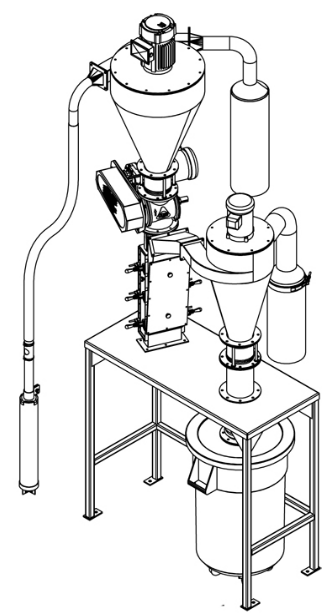
6DT8-2

This table top unit can be fed from a screw conveyor, overhead surge bin or by hand. Ideal for



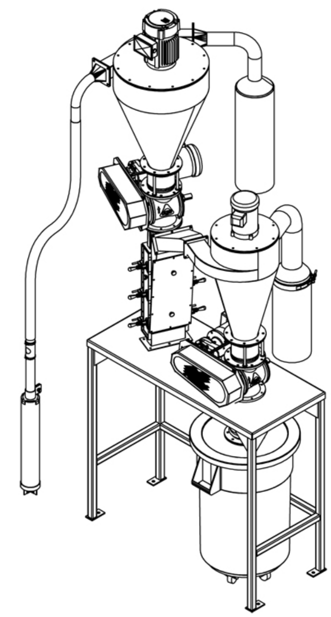
6DT8-3

Similar to the 6DT8-2, the 6DT8-3 comes with a cyclone and airlock added to the stock inlet



6DT8-4

A cyclone with an internal suction fan is mounted on the stock inlet of the Multi-Aspirator®. This



6DT8-5

Similar to the 6DT8-4, the 6DT8-5 includes an additional airlock below the receiving cyclone/fan.

small cleaning jobs or batch type operations. The suction fan is located in the top of the receiving cyclone. A cyclone discharges liftings into an air tight container below the support table.

of the Multi-Aspirator®. This arrangement allows for the system to be fed by a small pneumatic conveying line.

allows product to be conveyed by negative pressure to the system from a gaylord or other open container sitting next to the system.

This allows for an open top container below.

Back To Top

PDF Dimension Sheets

- 4E Series
- 4F Series
- 6E Series
- 6F Series
- Air Outlet Transitions
- Return Air Plenums

Online Store

Quick Ship
SPARE PARTS

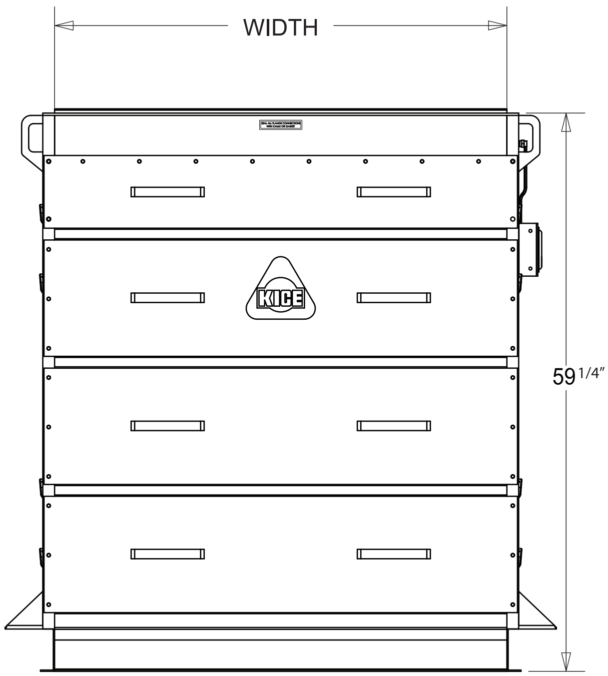
Operations
MANUALS

Trade Show
SCHEDULE

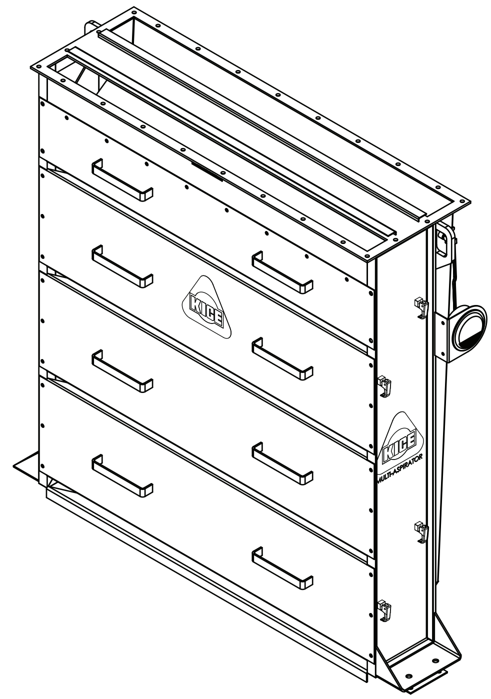
The Kice
CULTURE

4E SERIES MULTI-ASPIRATOR

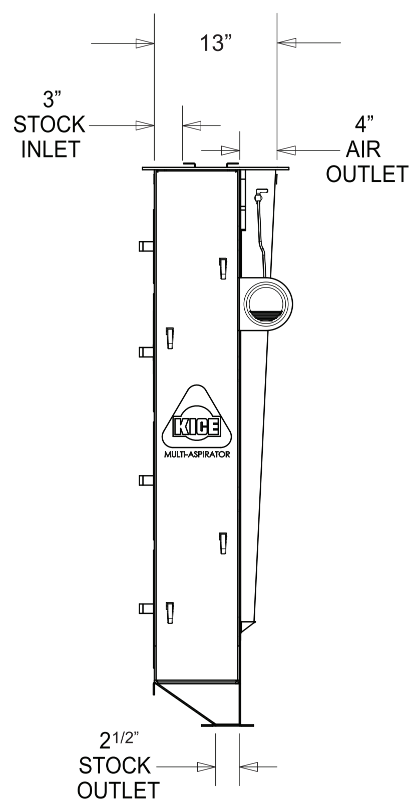
KICE INDUSTRIES, INC. / 5500 Mill Heights Drive / Wichita, KS 67219 www.kice.com / sales@kice.com



FRONT VIEW



MODEL #	WIDTH	EST. WEIGHT
4E6	6	143
4E12	12	183
4E18	18	222
4E24	24	262
4E30	30	302
4E36	36	342
4E42	42	382
4E48	48	407
4E60	60	499
4E72	72	579
4E84	84	659
4E96	96	739
4E108	108	819
4E120	120	899
4E132	132	979
4E138	138	1,014



SIDE VIEW

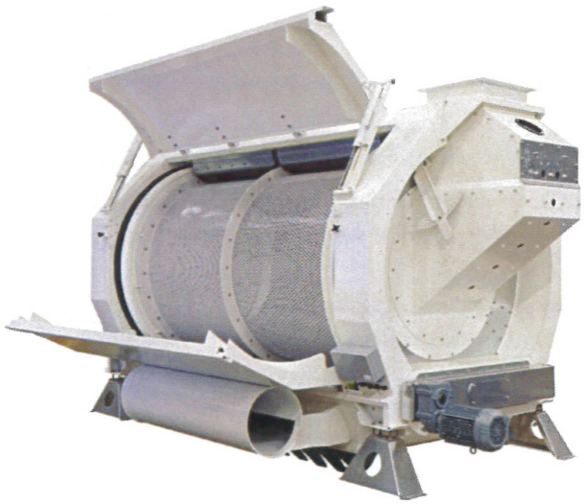
4E MULTI-ASPIRATOR

DWG. NO. ASP-1001

Data Sheet 150

Cimbria Drum Scalper Type DS-1250

The Cimbria Drum Scalper has been developed for heavy duty rough cleaning of Oil seed and other products as grain and maize.



The 7,8 m² of screen area is separating coarse impurities and foreign materials like stones, large straw, maize cobs etc.

The efficiency of the screen is supported by the horizontal airflow below the drum, which collect dust and fines from the product.

High wear areas are covered with replaceable PEHD wear liners.

Rough cleaning based on following: Incoming product up to 10 % impurities (with moisture content as given below)	
Wheat, 15 % mc.	500 t/h
Wheat, Barley, Maize 20 % mc.	400 t/h
Sorghum, Rape seed 20 % mc.	400 t/h
Sunflower seed, 14% mc.	150 t/h
Soya Beans, Peas 20 % mc.	350 t/h
Paddy rice, Green coffee 20 % mc.	150 t/h
Maize, 35 % mc.	250 t/h
Oates 20% mc.	200 t/h
Dimensions:	
Machine height	2100 mm
Machine length	3500 mm
Machine width	2070 mm
Diameter screen	1250 mm
Screen area	7,8 m²
Inlet connection Q40	400 x 400 mm
Outlet connections Q40	400 x 400 mm
Motor:	
Drive for Drum	2,2 kW
Drum rotation	12 rpm
Required Air volume to aspiration system:	
External suction (60 mm WG)	5.000 m³/h
Total weight of the cleaner:	1750 kg
Freight volume	15 m³

The technical data can vary sometimes because of redevelopment of the machine or another combination of the machine.

04.12
sma/hvb

Cimbria Bratney Companies . 3400-109th Street Des Moines, IA 50322. Tel. 800-247-6755 . Fax 515-270-2390
Web: www.bratney.com . E-mail: cim@bratney.com . Member of the Cimbria Group of Companies