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December 5, 2014

ATTN: Elizabeth Nakanishi
Air Permit Program Permit Intake Clerk
Alaska Department of Environmental Conservation
Air Permit Program
619 E. Ship Creek, Suite 249
Anchorage, Alaska 99501

Subject: Amendment to Operating Permit Renewal Application for Title V Operating Permit No. AQ0316TVP02 for the University of Alaska Fairbanks Campus

Dear Ms. Nakanishi:

The University of Alaska Fairbanks (UAF) is submitting the enclosed amendment to the permit renewal application for the above mentioned permit pursuant to 40 Code of Federal Regulations (CFR) 71, adopted by reference at 18 Alaska Administrative Code (AAC) 50.326(a) and (c).

The purpose of this application amendment is to request changes to the existing Title V permit conditions and the previously submitted Title V permit renewal application to provide increased operating flexibility. Specifically, UAF is requesting a revision to Condition 17 which would allow Emission Unit (EU) 4 to operate with or without the 10 percent capacity factor limit. Once operating without the capacity factor limit, additional requirements in 40 CFR 60 Subpart Db will be applicable. UAF is therefore requesting revisions to Conditions 39 through 41 to reflect the additional applicable requirements. UAF is also proposing revisions to Conditions 39 through 41 for clarity and to incorporate amendments to Subpart Db. EU 4 will remain subject to the limits in Conditions 15 and 16. Condition 15 limits combined SO_2 emissions from EU 4 and EU 8 to less than 40 tons per year. Condition 16 limits combined NO_X emissions from EU 4 and EU 8 to less than 40 tons per year.

Permitting an operating scenario which allows EU 4 to operate without the 10 percent capacity factor limit and comply with the applicable NSPS requirements is a revision to a Title V permit condition. The limit appeared in Condition 12 of Permit No. AQ0316TVP01 and in Condition 11 of Permit No. AQ0316TVP01, Revision 3. Condition 9 of Permit No. AQ0316MSS02 revised the limit of 795,000 gallons of distillate fuel per year to an equivalent heat input limit of 158,468 MMBtu per year to account for the addition of natural gas as a permitted fuel.

The option to operate EU 4 without the 10 percent capacity factor does not trigger Title I permitting requirements, as detailed in Attachments E and F of this application amendment.

This amendment revises several elements of the application. These updated elements are attached to this letter as described below:

Attachment	Description	Original Application Section
A	Requests additional revisions to various permit conditions.	Section 5, Table 5-1
B	Provides applicability analysis for EU 4 with 10 percent capacity factor - 40 CFR 60 Subpart Db	Section 3, Tables 3-1 and 3-2, Section 5, Table 5-1
C	Provides applicability analysis for EU 4 without 10 percent capacity factor - 40 CFR 60 Subpart Db	Section 3, Tables 3-1 and 3-2, Section 5, Table 5-1
D	Updates emission calculations. Includes changes to EU 4 potential emissions and reflects amendments to 40 CFR 98 Subpart C emission factors for greenhouse gases.	Section 2, Tables 2-1 through 2-21
E	Rationale for Title V permit revision for EU 4.	N/A
F	Permit applicability calculations for change to EU 4.	N/A

Please note that the ADEC Title V Standard Application Forms were not used to prepare this amendment because the original application was submitted prior to the date that the forms were required. The amendment is provided in a format consistent with the original application for ease of comparison.

If you have any questions or need additional information, please contact Frances M. Isgrigg, PE at 907-474-5487 or by email at fisgrigg@alaska.edu.

Certification Statement: "Based on information and belief formed after reasonable inquiry, I certify that the statements and information in and attached to this document are true, accurate, and complete."

Sincerely,

Scott Bell
Associate Vice Chancellor for Facilities Services

Enclosure: Operating Permit Renewal Application Amendment Attachments A through F

cc: D. McLerran, USEPA – Seattle (w/attachment)
F. Isgrigg, UAF – Fairbanks (w/o attachment)
C. Kimball, SLR – Fairbanks (w/o attachment)

Attachment A
Title V Condition Change Requests

The University of Alaska Fairbanks (UAF) requests that the Alaska Department of Environmental Conservation (ADEC) revise several conditions in Permit No. AQ0316TVP02. These requested changes are described below.

Condition 15. Please revise Condition 15 to clarify that Emission Units (EUs) 4 and 8 are subject to a combined sulfur dioxide (SO_2) emissions limit for purposes of Prevention of Significant Deterioration (PSD) avoidance. The existing permit condition does not explicitly state the PSD avoidance limit. Please note that UAF submitted a minor permit application in August 2014 which requests additional revisions to the corresponding Condition 11 in Permit No. AQ0316MSS02. Those requested changes are also reflected below.

15. The Permittee shall limit the combined SO_2 emissions from EU IDs 4 and 8 to less than 40 tons per year.

15.1 No later than the 15th day of each month, calculate the previous month's SO_2 emissions using Equation 1. Record the total.

Equation 1 $$SO_2 = [(FC_4 + FC_8)\ (\rho)\ (\%S/100)(2)](1/2000)$$

where:

SO_2	= SO_2 emissions (ton/month)
FC_4	= Liquid fuel consumption for EU ID 4 (gal/month), recorded under the provisions described in condition 14
FC_8	= Liquid fuel consumption for EU ID 8 (gal/month), recorded under the provisions described in condition 14
ρ	= Density of the liquid fuel (lb/gal)
%S	= Most recent sulfur content of the diesel fuel, percent by weight, recorded under the provisions described in condition 14
100	= Conversion factor from percent to a fraction
2	= Molecular weight ratio of SO_2 to S
2,000	= Conversion factor from lbs to tons

15.2 Record and report in accordance with condition 79 the 12 consecutive monthly total SO_2 emissions in units of tons per year for each of the past 6 months.

15.3 Report in accordance with condition 78 when the 12 consecutive monthly total SO_2 emissions equal or exceed 40 tons.

Condition 17. Please revise Condition 17 to provide the option of operating EU 4 either under the annual 10 percent capacity factor or the applicable NO_X emission standards in 40 CFR 60 Subpart Db. UAF is also proposing revisions to Condition 17.1b (Condition 17.2 in Permit No. AQ0316TVP02, Revision 1) to clarify the timeline for calculating and recording information and to remove the requirement to record "past information."

17. The Permittee shall comply with Condition 17.1 or Condition 17.2. If the Permittee switches from complying with Condition 17.1 to complying with Condition 17.2, or switches from

complying with Condition 17.2 to complying with Condition 17.1, the Permittee shall notify the Department within 30 days after the switch, and provide the date on which the switch was made.

17.1 Limit the annual capacity factor to 10% by not exceeding the heat input rate of 158,468 MMBtu/yr for EU ID 4 in any 12 consecutive months.

a. The Permittee shall record calendar date, daily hours of operation, and hourly steam load.

b. Maintain and operate a system approved by the Department to monitor and record the daily fuel consumption. By the end of each calendar month, calculate and record the fuel consumption for the previous month, and the rolling 12-month fuel consumption for the previous 12 months. Calculate and record the annual capacity factor by the end of each calendar month.

c. Semi-annual reports shall be submitted to the EPA Administrator, shall be postmarked by the 30th day following the end of the reporting period, and shall contain: (1) the annual capacity factor over the previous 12 months, and (2) the hours of operation during the reporting period. Include copies of the six-month reports with the operating report required by Condition 79.

d. Submit a report in accordance with Condition 78 if any heat input rate for any 12 consecutive months exceeds 158,468 MMBtu/yr.

17.2 Comply with Condition 16 and the applicable NO_X emission standards and MR&R requirements in Condition 41.

<u>Conditions 39 through 41.</u> Please revise Conditions 39 through 41 to provide the complete list of applicable requirements in 40 CFR 60 Subpart Db, whether EU 4 operates under Condition 17.1 or 17.2 above. The proposed changes also update and clarify the applicable Subpart Db requirements because the regulation has been amended since these conditions were originally written.

39. For EU ID 4, comply with the applicable provisions of Subpart Db to 40 CFR 60 at all times, as follows.

39.1 Standard for SO_2: Comply with 40 CFR 60.42b(a), 60.42b(e), 60.42b(g), and 60.42b(j), and (j)(2).

39.2 Compliance and performance test methods and procedures for SO_2: Comply with 40 CFR 60.45b(a), 60.45b(j), and 60.45b(k).

39.3 Emission monitoring for SO_2: Comply with 40 CFR 60.47b(f).

39.4 Standard for PM: Comply with the opacity standards in 40 CFR 60.43b(f) and 60.43b(g).

39.5 Compliance and performance test methods and procedures for PM: Comply with the opacity requirements in 40 CFR 60.46b(a). Comply with 60.46b(d)(7) if not operating a COMS, as provided in 40 CFR 60.48b(j).

39.6 Emission monitoring for PM: Comply with the opacity requirements in 40 CFR 60.48b(a) and 60.48b(e). Comply with 40 CFR 60.48b(j) and 60.48b(l) if the Permittee is not operating a COMS, as provided in 40 CFR 60.48b(j).

39.7 Reporting and Recordkeeping Requirements: Comply with the requirements in 40 CFR 60.49b(d), 60.49b(f), 60.49b(h), (h)(1), and (h)(3), 60.49b(j), 60.49b(o), 60.49b(r), 60.49b(v), and 60.49b(w).

40. For EU ID 4, when complying with Condition 17.1, comply with the reporting and recordkeeping requirements in 40 CFR 60.49b(p) and 60.49b(q), in addition to complying with Condition 39. As provided in 40 CFR 60.44b(j) and (k) and 60.48b(i), EU ID 4 is not subject to the Subpart Db NO_X emission limits and associated monitoring requirements when complying with Condition 17.1.

41. For EU ID 4, when complying with Condition 17.2, comply with the applicable provisions of Subpart Db to 40 CFR 60 as follows, in addition to complying with Condition 39.

41.1 Standard for NO_X: Comply with 40 CFR 60.44b(a), 60.44b(h), and 60.42b(i). The applicable NO_X emission limit (expressed as NO_2) for EU ID 4 is 0.20 lb/MMBtu heat input, as listed in Item (1)(ii) in the table in 40 CFR 60.44b(a).

41.2 Compliance and performance test methods and procedures for NO_X: Comply with 40 CFR 60.46b(c) and 60.46b(e), (e)(1), and (e)(4).

41.3 Emission monitoring for NO_X: Comply with 40 CFR 60.48b(b), 60.48b(c), 60.48b(d), 60.48b(e), (e)(2), and (e)(3), 60.48b(f), and 60.48b(g).

41.4 Reporting and Recordkeeping Requirements: Comply with the requirements in 40 CFR 60.49b(b), 60.49b(c), 60.49b(g), 60.49b(h)(2) and (h)(4), and 60.49b(i).

Attachment B
40 Code of Federal Regulation Part 60 Subpart Db
Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

University of Alaska Fairbanks Campus
The requirements for the following emission unit are outlined below:

Emission Unit: EU 4, Oil and Natural Gas-fired Boiler, Maximum Heat Input Rating of 180.9 million British thermal units per hour (MMBtu/hr). Installed in 1987.

Note: Only those provisions of 40 CFR 60 Subpart Db applicable to Emission Unit EU 4 when subject to the 10 percent capacity factor limit are included in the listing below. Because the boiler went through initial startup in the late 1980s, one-time requirements applicable only upon initial startup are not included.

§ 60.40b Applicability and delegation of authority.

(a) The affected facility to which this subpart applies is each steam generating unit that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/hr)).

§ 60.42b Standard for sulfur dioxide (SO_2).

(a) Except as provided in paragraphs (b), (c), (d), or (j) of this section, on and after the date on which the performance test is completed or required to be completed under §60.8, whichever 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 oil shall cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu).

(e) Compliance with the emission limits, fuel oil sulfur limits under this section are determined on a 30-day rolling average basis.

(g) The SO_2 emission limits under this section apply at all times, including periods of startup, shutdown, and malfunction.

(j) Percent reduction requirements are not applicable to affected facilities combusting only very low sulfur oil. The owner or operator of an affected facility combusting very low sulfur oil shall demonstrate that the oil meets the definition of very low sulfur oil by: (2) maintaining fuel records as described in §60.49b(r).

§ 60.43b   Standard for particulate matter (PM).

(f) 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 combusts oil, or mixtures of these fuels with any other fuels shall cause to be discharged into the atmosphere 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.

(g) The opacity standards apply at all times, except during periods of startup, shutdown, or malfunction.

§ 60.44b   Standard for nitrogen oxides (NO_X).

(j) …

(1) Combust, alone or in combination, only natural gas, distillate oil, or residual oil with a nitrogen content of 0.30 weight percent or less;

(2) Have a combined annual capacity factor of 10 percent or less for natural gas, distillate oil, and residual oil with a nitrogen content of 0.30 weight percent or less; and

(3) Are subject to a federally enforceable requirement limiting operation of the affected facility to the firing of natural gas, distillate oil, and/or residual oil with a nitrogen content of 0.30 weight percent or less and limiting operation of the affected facility to a combined annual capacity factor of 10 percent or less for natural gas, distillate oil, and residual oil with a nitrogen content of 0.30 weight percent or less.

(k) Affected facilities that meet the criteria described in paragraphs (j)(1), (2), and (3) of this section, and that have a heat input capacity of 73 MW (250 MMBtu/hr) or less, are not subject to the NO_X emission limits under this section.

§ 60.45b   Compliance and performance test methods and procedures for sulfur dioxide.

(a) The SO_2 emission standards in § 60.42b apply at all times.

(j) The owner or operator of an affected facility that only combusts very low sulfur oil, natural gas, or a mixture of these fuels with any other fuels not subject to an SO_2 standard is not subject to the compliance and performance testing requirements of this section if the owner or operator obtains fuel receipts as described in §60.49b(r).

(k) The owner or operator of an affected facility seeking to demonstrate compliance in §60.42b(j) shall follow the applicable procedures in § 60.49b(r).

§ 60.46b Compliance and performance test methods and procedures for particulate matter and nitrogen oxides.

(a) The opacity limits under § 60.43b apply at all times except during periods of startup, shutdown, or malfunction.

(d) To determine compliance with the opacity limits under §60.43b, the owner or operator of an affected facility shall conduct an initial performance test as required under §60.8, and shall conduct subsequent performance tests as requested by the Administrator, using the following procedures and reference methods:

> (7) Method 9 of appendix A of this part is used for determining the opacity of stack emissions.

§ 60.47b Emission monitoring for sulfur dioxide.

(f) The owner or operator of an affected facility that combusts very low sulfur oil or is demonstrating compliance under § 60.45b(k) is not subject to the emission monitoring requirements under paragraph (a) of this section if the owner or operator maintains fuel records as described in § 60.49b(r).

§ 60.48b Emission monitoring for particulate matter and nitrogen oxides.

(a) Except as provided in paragraph (j) of this section, the owner or operator of an affected facility subject to the opacity standard under § 60.43b shall install, calibrate, maintain, and operate a continuous opacity monitoring systems (COMS) for measuring the opacity of 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 under § 60.43b and meeting the conditions under paragraphs (j)(1), (2), (3), (4), (5), or (6) of this section who 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 § 60.43b within 45 days of stopping use of an existing COMS 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 § 60.46d(d)(7).

(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.

(e) The procedures under §60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems.

(i) The owner or operator of an affected facility described in §60.44b(j) or §60.44b(k) is not required to install or operate a CEMS for measuring NO_X emissions.

(j) The owner or operator of an affected facility that meets the conditions in either paragraph (j)(1), (2), (3), (4), (5), (6), or (7) of this section is not required to install or operate a COMS if:

(2) The affected facility burns only liquid (excluding residual oil) or gaseous fuels with potential SO_2 emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and does not use a post-combustion technology to reduce SO_2 or PM emissions. The owner or operator must maintain fuel records of the sulfur content of the fuels burned, as described under §60.49b(r); or
(7) The affected facility burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur and operates 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.

[Note – the exemptions under 60.48b(j)(2) or (j)(7) are applicable and can be used.]

(l) An owner or operator of an affected facility that is subject to an opacity standard under §60.43b(f) is not required to operate a COMS provided that the unit burns only gaseous fuels and/or liquid fuels (excluding residue oil) with a potential SO_2 emissions rate no greater than 26 ng/J (0.060 lb/MMBtu), and the unit operates according to a written site-specific monitoring plan approved by the permitting authority is not required to operate a COMS. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard. 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 §60.49b(h).

§ 60.49b Reporting and recordkeeping requirements.

(d) Except as provided in paragraph (d)(2) of this section, the owner or operator of an affected facility shall record and maintain records as specified in paragraph (d)(1) of this section.

(1) The owner or operator of an affected facility shall record and maintain records of the amounts of each fuel combusted during each day and calculate the annual capacity factor individually for coal, distillate oil, residual oil, natural gas, wood, and municipal-type solid waste for the reporting period. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month.

(f) For an affected facility subject to the opacity standard in § 60.43b, the owner or operator shall maintain records of opacity. In addition, an owner or operator that elects to monitor emissions according to the requirements in § 60.48b(a) shall maintain records according to the requirements specified in paragraphs (f)(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 (f)(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 (f)(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.

(h) The owner or operator of any affected facility in any category listed in paragraphs (h)(1) or (2) of this section is required to submit excess emission reports for any excess emissions that occurred during the reporting period.

(1) Any affected facility subject to the opacity standards in § 60.43b(f) or to the operating parameter monitoring requirements in § 60.13(i)(1).

(3) For the purpose of § 60.43b, excess emissions are defined as all 6-minute periods during which the average opacity exceeds the opacity standards under § 60.43b(f).

(j) The owner or operator of any affected facility subject to the SO_2 standards under § 60.42b shall submit reports.

(o) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of 2 years following the date of such record.

(p) The owner or operator of an affected facility described in §60.44b(j) or (k) shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date;

(2) The number of hours of operation; and

(3) A record of the hourly steam load.

(q) The owner or operator of an affected facility described in §60.44b(j) or §60.44b(k) shall submit to the Administrator a report containing:

(1) The annual capacity factor over the previous 12 months;

(3) If the affected facility meets the criteria described in §60.44b(j), the results of any NO_X emission tests required during the reporting period, the hours of operation during the reporting period, and the hours of operation since the last NO_X emission test.

(r) The owner or operator of an affected facility who elects to use the fuel based compliance alternatives in § 60.42b or § 60.43b shall either:

(1) The owner or operator of an affected facility who elects to demonstrate that the affected facility combusts only very low sulfur oil, natural gas, wood, a mixture of these fuels, or any of these fuels (or a mixture of these fuels) in combination with other fuels that are known to contain an insignificant amount of sulfur in § 60.42b(j) or § 60.42b(k) shall obtain and maintain at the affected facility fuel receipts (such as a current, valid purchase contract, tariff sheet, or transportation contract) from the fuel supplier that certify that the oil meets the definition of distillate oil and gaseous fuel meets the definition of natural gas as defined in § 60.41b and the applicable sulfur limit. For the purposes of this section, the distillate oil need not meet the fuel nitrogen content specification in the definition of distillate oil. Reports shall be submitted to the Administrator certifying that only very low sulfur oil meeting this definition, natural gas, wood, and/or other fuels that are known to contain insignificant amounts of sulfur were combusted in the affected facility during the reporting period; or

(2) The owner or operator of an affected facility who elects to demonstrate compliance based on fuel analysis in § 60.42b or § 60.43b shall develop and submit a site-specific fuel analysis plan to the Administrator for review and approval no later than 60 days before the date you intend to demonstrate compliance. Each fuel analysis plan shall include a minimum initial requirement of weekly testing and each analysis report shall contain, at a minimum, the following information:

(i) The potential sulfur emissions rate of the representative fuel mixture in ng/J heat input;

(ii) The method used to determine the potential sulfur emissions rate of each constituent of the mixture. For distillate oil and natural gas a fuel receipt or tariff sheet is acceptable;

(iii) The ratio of different fuels in the mixture; and

(iv) The owner or operator can petition the Administrator to approve monthly or quarterly sampling in place of weekly sampling.

[Note: UAF currently complies under 60.49b(r)(1) and likely does not plan on using the option under 60.49b(r)(2).]

(v) The owner or operator of an affected facility may submit electronic quarterly reports for SO_2 and/or NO_X and/or opacity in lieu of submitting the written reports required under paragraphs (h), (i), (j), (k) or (l) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format.

(w) The reporting period for the reports required under this subpart is each 6 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.

Attachment C
40 Code of Federal Regulation Part 60 Subpart Db
Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

University of Alaska Fairbanks Campus
The requirements for the following emission unit are outlined below:

Emission Unit: EU 4, Oil and Natural Gas-fired Boiler, Maximum Heat Input Rating of 180.9 million British thermal units per hour (MMBtu/hr). Installed in 1987.

Note: Only those provisions of 40 CFR 60 Subpart Db applicable to Emission Unit EU 4 are included in the listing below. Because the boiler went through initial startup in the late 1980s, one-time requirements applicable only upon initial startup are not included.

§ 60.40b Applicability and delegation of authority.

(a) The affected facility to which this subpart applies is each steam generating unit that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/hr)).

§ 60.42b Standard for sulfur dioxide (SO_2).

(a) Except as provided in paragraphs (b), (c), (d), or (j) of this section, on and after the date on which the performance test is completed or required to be completed under § 60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts oil shall cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu).

(e) Compliance with the emission limits, fuel oil sulfur limits, under this section are determined on a 30-day rolling average basis.

(g) Except as provided in paragraph (i) of this section and § 60.45b(a), the SO_2 emission limits under this section apply at all times, including periods of startup, shutdown, and malfunction.

(j) Percent reduction requirements are not applicable to affected facilities combusting only very low sulfur oil. The owner or operator of an affected facility combusting very low sulfur oil shall demonstrate that the oil meets the definition of very low sulfur oil by: (2) maintaining fuel records as described in § 60.49b(r).

§ 60.43b Standard for particulate matter (PM).

(f) 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 combusts oil, or mixtures of these fuels with any other fuels shall cause to be discharged into the atmosphere 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.

(g) The opacity standards apply at all times, except during periods of startup, shutdown, or malfunction.

§ 60.44b Standard for nitrogen oxides (NO_X).

(a) Except as provided under paragraphs (k) and (l) of this section, 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 is subject to the provisions of this section and that combusts only oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X (expressed as NO_2) in excess of the following emission limits:

Fuel/steam generating unit type	Nitrogen oxide emission limits (expressed as NO_2) heat input	
	ng/J	lb/MMBTu
(1) Natural gas and distillate oil, except (4):		
(ii) High heat release rate	86	0.20

[Note that EU 4 has a high heat release rate per the definition in §60.41b.]

(h) For purposes of paragraph (i) of this section, the NO_X standards under this section apply at all times including periods of startup, shutdown, or malfunction.

(i) Compliance with the emission limits under this section is determined on a 30-day rolling average basis.

§ 60.45b Compliance and performance test methods and procedures for sulfur dioxide.

(a) The SO_2 emission standards in § 60.42b apply at all times.

(j) The owner or operator of an affected facility that only combusts very low sulfur oil, natural gas, or a mixture of these fuels with any other fuels not subject to an SO_2 standard is not subject to the compliance and performance testing requirements of this section if the owner or operator obtains fuel receipts as described in §60.49b(r).

(k) The owner or operator of an affected facility seeking to demonstrate compliance in §60.42b(j) shall follow the applicable procedures in § 60.49b(r).

§ 60.46b Compliance and performance test methods and procedures for particulate matter and nitrogen oxides.

(a) The opacity limits under § 60.43b apply at all times except during periods of startup, shutdown, or malfunction. The NO_X emission standards under § 60.44b apply at all times.

(c) Compliance with the NO_X emission standards under § 60.44b shall be determined through performance testing under paragraph (e) of this section, as applicable.

(d) To determine compliance with the opacity limits under §60.43b, the owner or operator of an affected facility shall conduct an initial performance test as required under §60.8, and shall conduct subsequent performance tests as requested by the Administrator, using the following procedures and reference methods:

> (7) Method 9 of appendix A of this part is used for determining the opacity of stack emissions.

(e) To determine compliance with the emission limits for NO_X required under § 60.44b, the owner or operator of an affected facility shall conduct the performance test as required under § 60.8 using the continuous system for monitoring NO_X under § 60.48(b).

> (1) For the initial compliance test, NO_X from the steam generating unit are monitored for 30 successive steam generating unit operating days and the 30-day average emission rate is used to determine compliance with the NO_X emission standards under § 60.44b. The 30-day average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 30-day test period.

> (4) Following the date on which the initial 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 has a heat input capacity of 73 MW (250 MMBtu/hr) or less and that combusts natural gas, distillate oil, gasified coal, or residual oil having a nitrogen content of 0.30 weight percent or less shall upon request determine compliance with the NO_X standards in § 60.44b through the use of a 30-day performance test. During periods when performance tests are not requested, NO_X emissions data collected pursuant to § 60.48b(g)(1) or § 60.48b(g)(2) are used to calculate a 30-day rolling average emission rate on a daily basis and used to prepare excess emission reports, but will not be used to determine compliance with the NO_X emission standards. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly NO_X emission data for the preceding 30 steam generating unit operating days.

§ 60.47b Emission monitoring for sulfur dioxide.

(f) The owner or operator of an affected facility that combusts very low sulfur oil or is demonstrating compliance under § 60.45b(k) is not subject to the emission monitoring requirements under paragraph (a) of this section if the owner or operator maintains fuel records as described in § 60.49b(r).

§ 60.48b Emission monitoring for particulate matter and nitrogen oxides.

(a) Except as provided in paragraph (j) of this section, the owner or operator of an affected facility subject to the opacity standard under § 60.43b shall install, calibrate, maintain, and operate a continuous opacity monitoring systems (COMS) for measuring the opacity of 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 under § 60.43b and meeting the conditions under paragraphs (j)(1), (2), (3), (4), (5), or (6) of this section who 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 § 60.43b within 45 days of stopping use of an existing COMS 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 § 60.46d(d)(7).

(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) Except as provided under paragraphs (g), (h), and (i) of this section, the owner or operator of an affected facility subject to a NO_X standard under § 60.44b shall comply with paragraph (b)(1) of this section.

(1) Install, calibrate, maintain, and operate CEMS for measuring NO_X and O_2 (or CO_2) emissions discharged to the atmosphere, and shall record the output of the system

(c) The CEMS required under paragraph (b) of this section 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.

(d) The 1-hour average NO_X emission rates measured by the continuous NO_X monitor required by paragraph (b) of this section and required under § 60.13(h) shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the average emission rates under § 60.44b. The 1-hour averages shall be calculated using the data points required under § 60.13(h)(2).

(e) The procedures under § 60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems.

(2) For affected facilities combusting oil, or natural gas, the span value for NO_X is determined using one of the following procedures:

(i) Except as provided under paragraph (e)(2)(ii) of this section, NO_X span values shall be determined as follows:

Fuel	**Span values for NO_X (ppm)**
Natural gas	500.
Oil	500.

Where:
x = Fraction of total heat input derived from natural gas;
y = Fraction of total heat input derived from oil; and
z = Fraction of total heat input derived from coal.

(3) All span values computed under paragraph (e)(2)(i) of this section for combusting mixtures of regulated fuels are rounded to the nearest 500 ppm.

(f) When NO_X emission data are not obtained because of CEMS breakdowns, repairs, calibration checks and zero and span adjustments, emission data will be obtained by using standby monitoring systems, Method 7 of appendix A of this part, Method 7A of appendix A of this part, or other approved reference methods to provide emission data for a minimum of 75 percent of the operating hours in each steam generating unit operating day, in at least 22 out of 30 successive steam generating unit operating days.

(g) The owner or operator of an affected facility that has a heat input capacity of 73 MW (250 MMBtu/hr) or less, and that has an annual capacity factor for residual oil having a nitrogen content of 0.30 weight percent or less, natural gas, distillate oil, gasified coal, or any mixture of these fuels, greater than 10 percent (0.10) shall:

(1) Comply with the provisions of paragraphs (b), (c), (d), (e)(2), (e)(3), and (f) of this section; or

(2) Monitor steam generating unit operating conditions and predict NO_X emission rates as specified in a plan submitted pursuant to §60.49b(c).

(j) The owner or operator of an affected facility that meets the conditions in either paragraph (j)(1), (2), (3), (4), (5), (6), or (7) of this section is not required to install or operate a COMS if:

(2) The affected facility burns only liquid (excluding residual oil) or gaseous fuels with potential SO_2 emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and does not use a post-combustion technology to reduce SO_2 or PM emissions. The owner or operator must maintain fuel records of the sulfur content of the fuels burned, as described under §60.49b(r);

(7) The affected facility burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur and operates 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.

[Note – the exemptions under 60.48b(j)(2) or (j)(7) are applicable and can be used.]

(l) An owner or operator of an affected facility that is subject to an opacity standard under §60.43b(f) is not required to operate a COMS provided that the unit burns only gaseous fuels and/or liquid fuels (excluding residue oil) with a potential SO_2 emissions rate no greater than 26 ng/J (0.060 lb/MMBtu), and the unit operates according to a written site-specific monitoring plan approved by the permitting authority is not required to operate a COMS. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard. 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 §60.49b(h).

§ 60.49b Reporting and recordkeeping requirements.

(b) The owner or operator of each affected facility subject to the SO_2 , PM, and/or NO_X emission limits under §§ 60.42b, 60.43b, and 60.44b shall submit to the Administrator the performance test data from the initial performance test and the performance evaluation of the CEMS using the applicable performance specifications in appendix B of this part.

(c) The owner or operator of each affected facility subject to the NO_X standard in §60.44b who seeks to demonstrate compliance with those standards through the monitoring of steam generating unit operating conditions in the provisions of §60.48b(g)(2) submit to the Administrator for approval a plan that identifies the operating conditions to be monitored in §60.48b(g)(2) and the records to be maintained in §60.49b(g). This plan shall be submitted to the Administrator for approval within 360 days of the initial startup of the affected facility. If the plan is approved, the owner or operator shall maintain records of predicted nitrogen oxide emission rates and the monitored operating conditions, including steam generating unit load, identified in the plan. The plan shall:

> (1) Identify the specific operating conditions to be monitored and the relationship between these operating conditions and NO_X emission rates (*i.e.*, ng/J or lbs/MMBtu heat input). Steam generating unit operating conditions include, but are not limited to, the degree of staged combustion (*i.e.*, the ratio of primary air to secondary and/or tertiary air) and the level of excess air (*i.e.*, flue gas O_2 level);
>
> (2) Include the data and information that the owner or operator used to identify the relationship between NO_X emission rates and these operating conditions; and
>
> (3) Identify how these operating conditions, including steam generating unit load, will be monitored under §60.48b(g) on an hourly basis by the owner or operator during the period of operation of the affected facility; the quality assurance procedures or practices that will be employed to ensure that the data generated by monitoring these operating conditions will be representative and accurate; and the type and format of the records of these operating conditions, including steam generating unit load, that will be maintained by the owner or operator under §60.49b(g).

[Note – because Boiler 4 started up over 20 years ago, a plan to demonstrate compliance using Predictive Emission Monitoring System (PEMS) cannot be submitted within 360 days of initial startup. Approval for PEMS as an alternative to CEMS would be pursuant to 40 CFR 60.13(i), per EPA ADI 0100010.]

(d) The owner or operator of an affected facility shall record and maintain records as specified in paragraph (d)(1) of this section.

> (1) The owner or operator of an affected facility shall record and maintain records of the amounts of each fuel combusted during each day and calculate the annual capacity factor

individually for coal, distillate oil, residual oil, natural gas, wood, and municipal-type solid waste for the reporting period. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month.

(f) For an affected facility subject to the opacity standard in § 60.43b, the owner or operator shall maintain records of opacity. In addition, an owner or operator that elects to monitor emissions according to the requirements in § 60.48b(a) shall maintain records according to the requirements specified in paragraphs (f)(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 (f)(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 (f)(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.

(g) The owner or operator of an affected facility subject to the NO_X standards under § 60.44b shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date;

(2) The average hourly NO_X emission rates (expressed as NO_2) (ng/J or lb/MMBtu heat input) measured or predicted;

(3) The 30-day average NO_X emission rates (ng/J or lb/MMBtu heat input) calculated at the end of each steam generating unit operating day from the measured or predicted hourly nitrogen oxide emission rates for the preceding 30 steam generating unit operating days;

(4) Identification of the steam generating unit operating days when the calculated 30-day average NO_X emission rates are in excess of the NO_X emissions standards under § 60.44b, with the reasons for such excess emissions as well as a description of corrective actions taken;

(5) Identification of the steam generating unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken;

(6) Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data;

(7) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted;

(8) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(9) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3; and

(10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part.

(h) The owner or operator of any affected facility in any category listed in paragraphs (h)(1) or (2) of this section is required to submit excess emission reports for any excess emissions that occurred during the reporting period.

(1) Any affected facility subject to the opacity standards in § 60.43b(f) or to the operating parameter monitoring requirements in § 60.13(i)(1).

(2) Any affected facility that is subject to the NO_X standard of § 60.44b, and that:

(i) Combusts natural gas, distillate oil, gasified coal, or residual oil with a nitrogen content of 0.3 weight percent or less; or

(ii) Has a heat input capacity of 73 MW (250 MMBtu/hr) or less and is required to monitor NO_X emissions on a continuous basis under § 60.48b(g)(1) or steam generating unit operating conditions under § 60.48b(g)(2).

(3) For the purpose of § 60.43b, excess emissions are defined as all 6-minute periods during which the average opacity exceeds the opacity standards under § 60.43b(f).

(4) For purposes of § 60.48b(g)(1), excess emissions are defined as any calculated 30-day rolling average NO_X emission rate, as determined under § 60.46b(e), that exceeds the applicable emission limits in § 60.44b.

(i) The owner or operator of any affected facility subject to the continuous monitoring requirements for NO_X under § 60.48(b) shall submit reports containing the information recorded under paragraph (g) of this section.

(j) The owner or operator of any affected facility subject to the SO_2 standards under § 60.42b shall submit reports.

(o) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of 2 years following the date of such record.

(r) The owner or operator of an affected facility who elects to use the fuel based compliance alternatives in § 60.42b or § 60.43b shall either:

(1) The owner or operator of an affected facility who elects to demonstrate that the affected facility combusts only very low sulfur oil, natural gas, wood, a mixture of these fuels, or any of these fuels (or a mixture of these fuels) in combination with other fuels that are known to contain an insignificant amount of sulfur in § 60.42b(j) or § 60.42b(k) shall obtain and maintain at the affected facility fuel receipts (such as a current, valid purchase contract, tariff sheet, or transportation contract) from the fuel supplier that certify that the oil meets the definition of distillate oil and gaseous fuel meets the definition of natural gas as defined in § 60.41b and the applicable sulfur limit. For the purposes of this section, the distillate oil need not meet the fuel nitrogen content specification in the definition of distillate oil. Reports shall be submitted to the Administrator certifying that only very low sulfur oil meeting this definition, natural gas, wood, and/or other fuels that are known to contain insignificant amounts of sulfur were combusted in the affected facility during the reporting period; or

(2) The owner or operator of an affected facility who elects to demonstrate compliance based on fuel analysis in § 60.42b or § 60.43b shall develop and submit a site-specific fuel analysis plan to the Administrator for review and approval no later than 60 days before the date you intend to demonstrate compliance. Each fuel analysis plan shall include a minimum initial requirement of weekly testing and each analysis report shall contain, at a minimum, the following information:

(i) The potential sulfur emissions rate of the representative fuel mixture in ng/J heat input;

(ii) The method used to determine the potential sulfur emissions rate of each constituent of the mixture. For distillate oil and natural gas a fuel receipt or tariff sheet is acceptable;

(iii) The ratio of different fuels in the mixture; and

(iv) The owner or operator can petition the Administrator to approve monthly or quarterly sampling in place of weekly sampling.

[Note: UAF currently complies under 60.49b(r)(1) and likely does not plan on using the option under 60.49b(r)(2).]

(v) The owner or operator of an affected facility may submit electronic quarterly reports for SO_2 and/or NO_X and/or opacity in lieu of submitting the written reports required under paragraphs (h), (i), (j), (k) or (l) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format.

(w) The reporting period for the reports required under this subpart is each 6 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.

Attachment D
Updated Emissions Estimate Calculations

Table 2-1. Assessable Emissions Summary
University of Alaska Fairbanks Campus

Emission Unit Type	Regulated Air Pollutant Emissions (tpy)[1,2]						
	NO_X	CO	PM_{10}	$PM_{2.5}$[3]	VOC	SO_2	HAP
Significant	643.8	397.7	81.5	39.5	17.5	896.2	20.2
Insignificant	2.6	1.7	1.6	1.6	3.1	1.6	
Total Stationary Source	**646**	**399**	**83**	**41**	**21**	**898**	**20.2**
Assessable Emission Subtotals	**646**	**399**	**83**	**41**	**21**	**898**	**20.2**
Fees Apply to Pollutant?[4]	**Yes**	**Yes**	**Yes**	**No**[5]	**Yes**	**Yes**	**No**[6]
Total Assessable Emissions	**2,047**						

Notes:

[1] Emissions are potential to emit, except where noted, based on maximum allowable operation and permit operating limits, where applicable.

[2] Regulated air pollutant calculations based on AP-42 emission factors, manufacturer data, and mass balances as shown in accompanying spreadsheets.

[3] $PM_{2.5}$ emissions are assumed to be equal to PM_{10} emissions except where noted on Table 2-7c.

[4] Fees paid on each regulated air pollutant emitted in quantities greater than 10 tpy per 18 AAC 50.410.

[5] $PM_{2.5}$ emissions are a subset of PM_{10} emissions and are excluded from the assessable emissions total to avoid a double payment.

[6] HAP emissions are a subset of either VOC emissions or PM_{10} and $PM_{2.5}$ emissions and are excluded from the assessable emissions total to avoid a double payment. No individual HAP is emitted at or above 10 tpy.

Highlighted fields indicate information which has been updated since the submittal of the Title V permit renewal application amendment in August 2013.

Table 2-2. Assessable Potential to Emit Emissions Inventory - Significant Emission Units
University of Alaska Fairbanks Campus

Emission Unit				Installation	Fuel Type	Maximum
ID	Description	Make/Model	Bldg. No.	Date		Rating/Capacity
1	Coal-Fired Boiler	Erie City	FS802	1962	Coal	84.5 MMBtu/hr[1]
2	Coal-Fired Boiler	Erie City	FS802	1962	Coal	84.5 MMBtu/hr[1]
3	Dual-Fired Boiler	Zurn	FS802	1970	Dual Fuel	180.9 MMBtu/hr
4	Dual-Fired Boiler	Zurn	FS802	1987	Dual Fuel	180.9 MMBtu/hr[5]
~~6~~	~~Arctic Health Research Bldg. Emergency Generator~~	~~Cummins/NH2501PG~~	~~FS901~~	~~1968~~	~~Diesel~~	~~125 kW~~
~~7~~	~~Arctic Health Research Bldg. Emergency Generator~~	~~Cummins/NH2501P~~	~~FS901~~	~~1968~~	~~Diesel~~	~~125 kW~~
8	Peaking/Backup Generator (DEG) Engine	Fairbanks Morse Colt-Pielstick PC2.6	FS817	1999	Diesel[3]	13,266 hp
9A	BiRD Incinerator	Therm-Tec/G-30P-1H	FS919	2006	Medical/Infectious Waste	83 lb/hr[4]
10	AFES Boiler	Burnham/V9OGA	AF256	2000	Diesel	1.08 MMBtu/hr[2]
11	AFES Boiler	Burnham/V9OGA	AF256	2000	Diesel	1.08 MMBtu/hr[2]
12	Harper Boiler #1	Weil McLain/BL776-S-W	FS420	1985	Diesel	0.64 MMBtu/hr[2]
13	Harper Boiler #2	Weil McLain/BL776-S-W	FS420	1985	Diesel	0.64 MMBtu/hr[2]
14	Copper Lane Boiler	Energy Kinetics System 2000	FS518	1985	Diesel	0.136 MMBtu/hr[2]
15	Copper Lane Boiler	Energy Kinetics System 2000	FS519	1985	Diesel	0.136 MMBtu/hr[2]
16	Copper Lane (Honor's House) Boiler	Weil McLain/P-WGO-5	FS520	2005	Diesel	0.233 MMBtu/hr[2]
17	West Ridge Research Building Boiler #1	Weil McLain/BL1688w-GPr10	FS909	2003	Diesel	4.93 MMBtu/hr[6]
18	West Ridge Research Building Boiler #2	Weil McLain/BL1688w-GPr10	FS909	2003	Diesel	4.93 MMBtu/hr[6]
19	BiRD RM 100U3 Boiler #1	Weil McLain/2094W	FS919	2004	Diesel	6.13 MMBtu/hr[2]
20	BiRD RM 100U3 Boiler #2	Weil McLain/2094W	FS919	2004	Diesel	6.13 MMBtu/hr[2]
21	BiRD RM 100U3 Boiler #3	Weil McLain/2094W	FS919	2004	Diesel	6.13 MMBtu/hr[2]
22	BiRD RM 100U3 Boiler #4	Bryan/EB200-S-150-FDGO	FS919	2005	Diesel	8.5 MMBtu/hr
23	Alaska Center for Energy and Power Generator Engine	Detroit Diesel/6043-TK35	FS814	2003	Diesel	235 kW
24	Old University Park Emergency Generator Engine	Cummins/4B3.9-G2	FS423	2001	Diesel	51 kW
25	AFES Grain Dryer	Unknown	AF108	1988	Diesel	2.43 MMBtu/hr[2]
26	Duckering Classroom Engine	Mitsubishi-Bosch	FS103	1987	Diesel	45 kW
27	Alaska Center for Energy and Power Generator Engine	Caterpillar C-15	FS814	TBD	Diesel	500 hp
28	Alaska Earthquake Information Center Emergency Generator Engine	Detroit Diesel	FS903	1998	Diesel	120 hp
29	Arctic Health Research Emergency Generator Engine	Cummins/QSB7-G6	FS901	2013	Diesel	314 hp

Notes:

[1] The rating of the coal-fired boilers as shown in Permit No. AQ0316TVP02 is incorrect. UAF has calculated the correct maximum heat input capacity. These calculations are provided in Section 2, Table 2-20 of this application.

[2] These external combustion units have nameplates which list the ratings in gross output or do not specify whether the rating is output or input. A 75 percent efficiency has been assumed for these units to conservatively calculate the heat input rating.

[3] EU 8 is also authorized to combust coal slurry fuel. The unit has not operated on this fuel and will not do so in the future. Emissions estimates for this unit are based on diesel fuel combustion.

[4] The rating of EU 9A is listed incorrectly in the existing Title V permit. The correct rating is provided here.

[5] Emission estimates for EU 4 are based on the 40 tpy NO_X limit in Condition 16 of Permit No. AQ0316TVP02, which are greater than estimates based on the capacity factor in Condition 17.

[6] The previous Title V renewal application proposed a limit of 500 hours per year for EU 17 and 18. This limit was not incorporated into the permit and UAF does not wish to apply an operating hour limit to these units.

[7] EU 5A listed on Permit No. AQ0316TVP02 has been removed.

Table 2-3. Assessable Potential to Emit Emissions Inventory - Insignificant Emission Units
University of Alaska Fairbanks Campus

Emission Unit				Installation	Fuel Type	Maximum	Basis for
ID	Description	Make/Model	Bldg. No.	Date		Rating/Capacity	Insignificance
30	AFES Greenhouse Furnace	Sunderman/L02OUF	AF117	1991	Diesel	0.209 MMBtu/hr[2]	18 AAC 50.326(g)(7)[9]
31	Copper Lane Furnace	Matzger	FS517	2001	Diesel	0.08 MMBtu/hr	18 AAC 50.326(g)(7)[9]
32	Skarland Cabin Furnace	Rheem/ROBC-084QPEB	FS712	2001 (est)	Diesel	0.140 MMBtu/hr[2]	18 AAC 50.326(g)(7)[9]
33	Harper Hot Water Heater	Bock	FS420	1985 (est)	Diesel	0.236 MMBtu/hr	18 AAC 50.326(g)(7)[9]
	Coal Handling/Crushing Facility	American Pulverizer	FS802	1964	Coal	50 tons/hr	18 AAC 50.326(e)
	Fine Arts/Arts Wing Rm 302 Kiln	Alpine Kilns and Equipment/SBF-40	FS313	2009	Propane	1.81 MMBtu/hr	18 AAC 50.326(g)(5)
	Fine Arts/Arts Wing Ceramic Rm 413 Kiln	Kilnmaster/constructed on-site	FS313	2009	Propane	0.53 MMBtu/hr[1]	18 AAC 50.326(g)(5)
	Fine Arts/Arts Wing Ceramic Rm 413 Kiln	Geil Kilns/DLB2	FS313	2009	Propane	0.23 MMBtu/hr	18 AAC 50.326(g)(5)
	Wooded Area Kiln(s)	Hand-built	N/A	Various	Wood	Unknown[3]	18 AAC 50.326(e)
	Facilities Services Paint Booth Exhaust Fan	Unknown	FS803	2001	Various Paints	12,500 cfm	18 AAC 50.326(e)
	Museum Paint Booth Exhaust Fan	Greenheck/TAB-42-030T3	FS907	2006	Various Paints	5,480 cfm	18 AAC 50.326(e)
	Laboratory Fume Hoods (campus-wide)[5]	N/A	Multiple	Various	N/A	N/A	18 AAC 50.326(f)(10)
	Duckering Classroom Turbine	Cussons Two Shaft Gas Turbine Unit	FS103	1970(est)	Propane	0.33 MMBtu/hr[8]	18 AAC 50.326(e)
	Power Plant Field-Erected Tank	Vertical Fixed Roof	FS817	1969	Diesel	212,120 gallons	18 AAC 50.326(e)
	Graduation Flame	Custom-built	N/A	1975(est)	Propane	5.0E-03 MMBtu/hr[4]	18 AAC 50.326(e)
	Ash Bin Vent filter	N/A	FS802	1962	N/A	8,760 hr/yr	18 AAC 50.326(e)
	Ash Vacuum Pump Filter	N/A	FS802	1962	N/A	8,760 hr/yr	18 AAC 50.326(e)
	Ash Loadout to Truck	N/A	FS802	1962	N/A	8,225 tpy ash	18 AAC 50.326(e)
	SRC Pellet Stove	Avalon/AGP	N/A	2012	Wood Pellets	5 lb/hr[7]	18 AAC 50.326(g)(6)

Notes:

[1] This external combustion unit has a nameplate which does not specify whether the rating is output or input. A 75 percent efficiency has been assumed to conservatively calculate the heat input rating.

[2] These external combustion units have nameplates which list the ratings in gross output or do not specify whether the rating is output or input. A 75 percent efficiency has been assumed for these units to conservatively calculate the heat input rating.

[3] UAF estimates that these units combust a cumulative maximum of 1 cord of dry birch wood per year.

[4] The graduation flame is a small propane flare that operates during graduation week. The rating is an estimate because the unit was hand-built by university personnel.

[5] The laboratory fume hoods are not required to be listed on the application per 18 AAC 50.326(d)(3), however they are listed here in order to quantify VOC and HAP emissions toward the assessable emission total.

[6] A paint booth is currently in place at the Hutchison technical high school on campus. This emission unit will no longer be used after December 2012 because the program is relocating off-campus.

[7] The SRC pellet stove has a heat input rating of 0.041 MMBtu/hr. Wood pellets have a heating value of 8,200 Btu/lb.

[8] Rating calculated based on vendor data that fuel consumption at 100 percent load is approximately 15 pounds of propane per hour.

[9] ADEC advised UAF on April 30, 2013 that ADEC considers these emission units to be insignificant.

Table 2-4. Assessable Potential to Emit Calculations - Oxides of Nitrogen (NO_X) Emissions
University of Alaska Fairbanks Campus

Emission Unit		Fuel Type	NO_X Emission Factor		Maximum Rating/Capacity	Allowable Annual Operation[1]	Potential NO_X Emissions[2]
ID	Description		Reference	Factor			
Significant Emission Units							
1	Coal-Fired Boiler	Coal	AP-42 Table 1.1-3	8.8 lb/ton	84.5 MMBtu/hr	8,760 hrs/yr	212.9 tpy
2	Coal-Fired Boiler	Coal	AP-42 Table 1.1-3	8.8 lb/ton	84.5 MMBtu/hr	8,760 hrs/yr	212.9 tpy
3	Dual-Fired Boiler	Diesel	AP-42 Table 1.3-1	24 lb/kgal	180.9 MMBtu/hr	8,760 hrs/yr	138.8 tpy[7]
3	Dual-Fired Boiler	Natural Gas	AP-42 Table 1.4-1 low NO_X	140 lb/MMscf	180.9 MMBtu/hr	8,760 hrs/yr	
~~6~~	~~Arctic Health Research Bldg. Emergency Generator~~	~~Diesel~~	~~AP-42 Table 3.3-1~~	~~0.031 lb/hp-hr~~	~~125 kW~~	~~hrs/yr~~	0.0 tpy
~~7~~	~~Arctic Health Research Bldg. Emergency Generator~~	~~Diesel~~	~~AP-42 Table 3.3-1~~	~~0.031 lb/hp-hr~~	~~125 kW~~	~~hrs/yr~~	0.0 tpy
4	Dual-Fired Boiler	Diesel	AP-42 Table 1.3-1	24 lb/kgal	180.9 MMBtu/hr	3,333 kgal/yr[19]	40.0 tpy[8]
4	Dual-Fired Boiler	Natural Gas	AP-42 Table 1.4-1 low NO_X	140 lb/MMscf	180.9 MMBtu/hr	571 MMscf/yr[19]	
8	Peaking/Backup Generator (DEG) Engine	Diesel	AQ0316MSS02, Cond.12.3b	0.057 lb/gal	13,266 hp	1,403,509 gal/yr[18]	
9A	BiRD Incinerator	Medical/Infectious Waste	AP-42 Table 2.3-1	3.56 lb/ton	83 lb/hr	109 ton/yr[9]	0.2 tpy
10	AFES Boiler	Diesel	AP-42 Table 1.3-1	20 lb/kgal	1.08 MMBtu/hr	8,760 hrs/yr	0.7 tpy
11	AFES Boiler	Diesel	AP-42 Table 1.3-1	20 lb/kgal	1.08 MMBtu/hr	8,760 hrs/yr	0.7 tpy
12	Harper Boiler #1	Diesel	AP-42 Table 1.3-1	20 lb/kgal	0.64 MMBtu/hr	8,760 hrs/yr	0.4 tpy
13	Harper Boiler #2	Diesel	AP-42 Table 1.3-1	20 lb/kgal	0.64 MMBtu/hr	8,760 hrs/yr	0.4 tpy
14	Copper Lane Boiler	Diesel	AP-42 Table 1.3-1	20 lb/kgal	0.136 MMBtu/hr	8,760 hrs/yr	0.1 tpy
15	Copper Lane Boiler	Diesel	AP-42 Table 1.3-1	20 lb/kgal	0.136 MMBtu/hr	8,760 hrs/yr	0.1 tpy
16	Copper Lane (Honor's House) Boiler	Diesel	AP-42 Table 1.3-1	20 lb/kgal	0.233 MMBtu/hr	8,760 hrs/yr	0.1 tpy
17	West Ridge Research Building Boiler #1	Diesel	AP-42 Table 1.3-1	20 lb/kgal	4.93 MMBtu/hr	8,760 hrs/yr	3.2 tpy
18	West Ridge Research Building Boiler #2	Diesel	AP-42 Table 1.3-1	20 lb/kgal	4.93 MMBtu/hr	8,760 hrs/yr	3.2 tpy
19	BiRD RM 100U3 Boiler #1	Diesel	AP-42 Table 1.3-1	20 lb/kgal	6.13 MMBtu/hr	19,650 hrs/yr[10]	8.8 tpy
20	BiRD RM 100U3 Boiler #2	Diesel	AP-42 Table 1.3-1	20 lb/kgal	6.13 MMBtu/hr		
21	BiRD RM 100U3 Boiler #3	Diesel	AP-42 Table 1.3-1	20 lb/kgal	6.13 MMBtu/hr		
22	BiRD RM 100U3 Boiler #4	Diesel	AP-42 Table 1.3-1	20 lb/kgal	8.50 MMBtu/hr	8,760 hrs/yr	5.4 tpy
23	Alaska Center for Energy and Power Generator Engine	Diesel	Vendor Data	1,630 g/hr	235 kW	4,380 hrs/yr[11]	7.9 tpy
24	Old University Park Emergency Generator Engine	Diesel	AP-42 Table 3.3-1	0.031 lb/hp-hr	51 kW	100 hrs/yr[16]	0.1 tpy
25	AFES Grain Dryer	Diesel	AP-42 Table 1.3-1	20 lb/kgal	2.427 MMBtu/hr	100 hrs/yr[12]	0.02 tpy
26	Duckering Classroom Engine	Diesel	AP-42 Table 3.3-1	0.031 lb/hp-hr	45 kW	99 hrs/yr[13,17]	0.1 tpy
27	Alaska Center for Energy and Power Generator Engine	Diesel	Vendor Data	3.52 lb/hr	500 hp	4,380 hrs/yr[14]	7.7 tpy
28	Alaska Earthquake Information Center Emergency Generator Engine	Diesel	AP-42 Table 3.3-1	0.031 lb/hp-hr	120 hp	100 hrs/yr[15]	0.2 tpy
29	Arctic Health Research Emergency Generator Engine	Diesel	EPA Tier 4i	0.4 g/kW-hr	314 hp	100 hrs/yr[3]	0.01 tpy
Significant Emission Units Total Assessable Potential to Emit Emissions - NO_X							**643.8 tpy**

Emission Unit ID	Emission Unit Description	Fuel Type	NO_X Emission Factor Reference	NO_X Emission Factor Factor	Maximum Rating/Capacity	Allowable Annual Operation[1]	Potential NO_X Emissions[2]
	Insignificant Emission Units						
30	AFES Greenhouse Furnace	Diesel	AP-42 Table 1.3-1	20 lb/kgal	0.209 MMBtu/hr	8,760 hrs/yr	0.1 tpy
31	Copper Lane Furnace	Diesel	AP-42 Table 1.3-1	20 lb/kgal	0.080 MMBtu/hr	8,760 hrs/yr	0.1 tpy
32	Skarland Cabin Furnace	Diesel	AP-42 Table 1.3-1	20 lb/kgal	0.140 MMBtu/hr	8,760 hrs/yr	0.1 tpy
33	Harper Hot Water Heater	Diesel	AP-42 Table 1.3-1	20 lb/kgal	0.236 MMBtu/hr	8,760 hrs/yr	0.2 tpy
	Coal Handling/Coal Crushing	Coal	N/A	N/A	N/A	8,760 hrs/yr	0.0 tpy
	Various Propane-Fired Kilns	Propane	AP-42 Table 1.5-1	13 lb/kgal	2.6 MMBtu/hr, total	8,760 hrs/yr	1.6 tpy
	Wood-Fired Kilns	Wood	AP-42 Table 1.6-2	0.49 lb/MMBtu[4]	Unknown	1 cord/yr[5]	3.7E-03 tpy
	Duckering Classroom Turbine	Propane	AP-42 Table 3.1-1	3.2E-01 lb/MMBtu[6]	0.33 MMBtu/hr	8,760 hrs/yr	0.5 tpy
	Graduation Flame	Propane	AP-42 Table 13.5-1	0.068 lb/MMBtu	5.0E-03 MMBtu/hr	8,760 hrs/yr	1.5E-03 tpy
	Various Paint Booths	N/A	N/A	N/A	N/A	8,760 hrs/yr	0.0 tpy
	Various Laboratory Fume Hoods	N/A	N/A	N/A	N/A	8,760 hrs/yr	0.0 tpy
	Power Plant Field-Erected Tank	Diesel	N/A	N/A	212,120 gallons	8,760 hrs/yr	0.0 tpy
	Ash Bin Vent filter	N/A	N/A	N/A	N/A	8,760 hrs/yr	0.0 tpy
	Ash Vacuum Pump Filter	N/A	N/A	N/A	N/A	8,760 hrs/yr	0.0 tpy
	Ash Loadout to Truck	N/A	N/A	N/A	N/A	8,225 tpy ash	0.0 tpy
	SRC Pellet Stove	Wood Pellets	AP-42 Table 1.10-1	13.8 lb/ton	5.0 lb/hr	8,760 hrs/yr	0.2 tpy
						Insignificant Emission Units Total Assessable Potential to Emit Emissions - NO_X	**2.6 tpy**
						Total Assessable Potential to Emit Emissions - NO_X	**646.4 tpy**

Notes:

[1] Maximum annual operation for all units based on full-time operation, or permit operating limits, where applicable.

[2] Conversion factors:

Mass conversion	454.0	g/lb
Diesel Heating Value	0.137	MMBtu/gal
Coal Heating Value	15.3	MMBtu/ton
Propane Heating Value	91.5	MMBtu/kgal
Natural Gas Heat Content	1,000	Btu/scf
Engine horsepower	1.341	kW
Assumed drive shaft efficiency for engines	95%	Per Alan Schuler at ADEC

[3] New emergency stationary internal combustion engines are limited to maintenance checks and readiness testing to no more than 100 hours per year, per 40 CFR 60.4211(f).

[4] Emission factor for small pottery-firing wood-fired kilns are not available. Calculation assumes that combustion of wood in the kilns is similar to that in dry wood-fired boilers.

[5] Approximate heat value of wood combusted in kilns is 15 MMBtu/cord, per http://www.hrt.msu.edu/energy/pdf/heating%20value%20of%20common%20fuels.pdf

[6] Emission factors for propane-fired turbine are not available. Emission factors for natural gas-fired turbine are used.

[7] The higher potential emissions for natural gas or distillate firing is shown as the potential emissions for EU 3.

[8] The combined NO_X emissions from EU 4 and EU 8 are limited to less than 40 tons per year, per Condition 16 of AQ0316TVP02.

[9] UAF is proposing an operating limit for EU 9A to avoid HAP major classification. Details are provided in Section 4 of this application.

[10] UAF is proposing operating limits for EU19 through EU21 to avoid minor permitting requirements for NO_X. Details are provided in Section 4 of this application.

[11] UAF is proposing an operating limit for EU 23 to avoid minor permitting requirements for NO_X. Details are provided in Section 4 of this application.

[12] UAF is proposing an operating limit for EU 25 to avoid PSD permitting requirements for SO_2. Details are provided in Section 4 of this application.

[13] UAF is proposing an operating limit for EU 26 to avoid PSD permitting requirements for NO_X. Details are provided in Section 4 of this application.

[14] Owner-requested limit of 4,380 hr/yr per AQ0316MSS03, currently being prepared by ADEC.

[15] Basis for EU 28 PTE calculated with 100 hr/yr: historical data indicating that engine operates approximately 13 hr/yr. A PTE basis of 100 hr/yr is conservatively high.

[16] Basis for EU 24 PTE calculated with 100 hr/yr. A PTE basis of 100 hr/yr is conservatively high; this engine is operated infrequently.

[17] Basis for EU 26 PTE calculated with 99 hr/yr. This engine is operated approximately 6 hours per year and is considered "limited use" under 40 CFR 63 Subpart ZZZZ.

[18] Maximum annual operation of EU 8 determined using lowest NO_X emission factor and assuming 40 tpy NO_X limit is consumed by EU 8.

[19] Maximum annual operation of EU 4 assumes 40 tpy NO_X limit is consumed by EU 4.

Table 2-5. Assessable Potential to Emit Calculations - Carbon Monoxide (CO) Emissions
University of Alaska Fairbanks Campus

Emission Unit ID	Emission Unit Description	Fuel Type	CO Emission Factor Reference	CO Emission Factor Factor	Maximum Rating/Capacity	Allowable Annual Operation[1]	Potential CO Emissions[2]
Significant Emission Units							
1	Coal-Fired Boiler	Coal	AP-42 Table 1.1-3	5 lb/ton	84.5 MMBtu/hr	8,760 hrs/yr	121.0 tpy
2	Coal-Fired Boiler	Coal	AP-42 Table 1.1-3	5 lb/ton	84.5 MMBtu/hr	8,760 hrs/yr	121.0 tpy
3	Dual-Fired Boiler	Diesel	AP-42 Table 1.3-1	5 lb/kgal	180.9 MMBtu/hr	8,760 hrs/yr	66.6 tpy[7]
3	Dual-Fired Boiler	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	180.9 MMBtu/hr	8,760 hrs/yr	
~~6~~	~~Arctic Health Research Bldg. Emergency Generator~~	~~Diesel~~	~~AP-42 Table 3.3-1~~	~~6.68E-03 lb/hp-hr~~	~~125 kW~~	~~0 hrs/yr~~	0.0 tpy
~~7~~	~~Arctic Health Research Bldg. Emergency Generator~~	~~Diesel~~	~~AP-42 Table 3.3-1~~	~~6.68E-03 lb/hp-hr~~	~~125 kW~~	~~0 hrs/yr~~	0.0 tpy
4	Dual-Fired Boiler	Diesel	AP-42 Table 1.3-1	5 lb/kgal	180.9 MMBtu/hr	3,333 kgal/yr[18]	75.5 tpy[8]
4	Dual-Fired Boiler	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	180.9 MMBtu/hr	571 MMscf/yr[18]	
8	Peaking/Backup Generator (DEG) Engine	Diesel	AP-42 Table 3.4-1	5.50E-03 lb/hp-hr	13,266 hp	1,403,509 gal/yr	
9A	BiRD Incinerator	Medical/Infectious Waste	AP-42 Table 2.3-1	2.95 lb/ton	83 lb/hr	109 ton/yr[9]	0.2 tpy
10	AFES Boiler	Diesel	AP-42 Table 1.3-1	5 lb/kgal	1.08 MMBtu/hr	8,760 hrs/yr	0.17 tpy
11	AFES Boiler	Diesel	AP-42 Table 1.3-1	5 lb/kgal	1.08 MMBtu/hr	8,760 hrs/yr	0.17 tpy
12	Harper Boiler #1	Diesel	AP-42 Table 1.3-1	5 lb/kgal	0.64 MMBtu/hr	8,760 hrs/yr	0.10 tpy
13	Harper Boiler #2	Diesel	AP-42 Table 1.3-1	5 lb/kgal	0.64 MMBtu/hr	8,760 hrs/yr	0.10 tpy
14	Copper Lane Boiler	Diesel	AP-42 Table 1.3-1	5 lb/kgal	0.136 MMBtu/hr	8,760 hrs/yr	0.02 tpy
15	Copper Lane Boiler	Diesel	AP-42 Table 1.3-1	5 lb/kgal	0.136 MMBtu/hr	8,760 hrs/yr	0.02 tpy
16	Copper Lane (Honor's House) Boiler	Diesel	AP-42 Table 1.3-1	5 lb/kgal	0.233 MMBtu/hr	8,760 hrs/yr	0.04 tpy
17	West Ridge Research Building Boiler #1	Diesel	AP-42 Table 1.3-1	5 lb/kgal	4.93 MMBtu/hr	8,760 hrs/yr	0.79 tpy
18	West Ridge Research Building Boiler #2	Diesel	AP-42 Table 1.3-1	5 lb/kgal	4.93 MMBtu/hr	8,760 hrs/yr	0.79 tpy
19	BiRD RM 100U3 Boiler #1	Diesel	AP-42 Table 1.3-1	5 lb/kgal	6.13 MMBtu/hr	19,650 hrs/yr[10]	2.20 tpy
20	BiRD RM 100U3 Boiler #2	Diesel	AP-42 Table 1.3-1	5 lb/kgal	6.13 MMBtu/hr		
21	BiRD RM 100U3 Boiler #3	Diesel	AP-42 Table 1.3-1	5 lb/kgal	6.13 MMBtu/hr		
22	BiRD RM 100U3 Boiler #4	Diesel	AP-42 Table 1.3-1	5 lb/kgal	8.5 MMBtu/hr	8,760 hrs/yr	1.36 tpy
23	Alaska Center for Energy and Power Generator Engine	Diesel	Vendor Data	144 g/hr	235 kW	4,380 hrs/yr[11]	0.7 tpy
24	Old University Park Emergency Generator Engine	Diesel	AP-42 Table 3.3-1	6.68E-03 lb/hp-hr	51 kW	100 hrs/yr[16]	0.02 tpy
25	AFES Grain Dryer	Diesel	AP-42 Table 1.3-1	5 lb/kgal	2.427 MMBtu/hr	100 hrs/yr[12]	0.00 tpy
26	Duckering Classroom Engine	Diesel	AP-42 Table 3.3-1	6.68E-03 lb/hp-hr	45 kW	99 hrs/yr[13,17]	0.02 tpy
27	Alaska Center for Energy and Power Generator Engine	Diesel	Vendor Data	3.14 lb/hr	500 hp	4,380 hrs/yr[14]	6.9 tpy
28	Alaska Earthquake Information Center Emergency Generator Engine	Diesel	AP-42 Table 3.3-1	6.68E-03 lb/hp-hr	120 hp	100 hrs/yr[15]	0.04 tpy
29	Arctic Health Research Emergency Generator Engine	Diesel	EPA Tier 4i	3.5 g/kW-hr	314 hp	100 hrs/yr[3]	0.09 tpy
Significant Emission Units Total Assessable Potential to Emit Emissions - CO							**397.7 tpy**

Emission Unit		Fuel Type	CO Emission Factor		Maximum Rating/Capacity	Allowable Annual	Potential CO
ID	Description		Reference	Factor		Operation[1]	Emissions[2]
			Insignificant Emission Units				
30	AFES Greenhouse Furnace	Diesel	AP-42 Table 1.3-1	5 lb/kgal	0.209 MMBtu/hr	8,760 hrs/yr	0.03 tpy
31	Copper Lane Furnace	Diesel	AP-42 Table 1.3-1	5 lb/kgal	0.080 MMBtu/hr	8,760 hrs/yr	0.01 tpy
32	Skarland Cabin Furnace	Diesel	AP-42 Table 1.3-1	5 lb/kgal	0.140 MMBtu/hr	8,760 hrs/yr	0.02 tpy
33	Harper Hot Water Heater	Diesel	AP-42 Table 1.3-1	5 lb/kgal	0.236 MMBtu/hr	8,760 hrs/yr	0.04 tpy
	Coal Handling/Coal Crushing	Coal	N/A	N/A	N/A	8,760 hrs/yr	0.0 tpy
	Various Propane-Fired Kilns	Propane	AP-42 Table 1.5-1	7.5 lb/kgal	2.6 MMBtu/hr, total	8,760 hrs/yr	0.92 tpy
	Wood-Fired Kilns	Wood	AP-42 Table 1.6-2	0.60 lb/MMBtu[4]	Unknown	1 cord/yr[5]	4.5E-03 tpy
	Duckering Classroom Turbine	Propane	AP-42 Table 3.1-1	8.2E-02 lb/MMBtu[6]	0.33 MMBtu/hr	8,760 hrs/yr	0.1 tpy
	Graduation Flame	Propane	AP-42 Table 13.5-1	0.37 lb/MMBtu	5.0E-03 MMBtu/hr	8,760 hrs/yr	8.1E-03 tpy
	Various Paint Booths	N/A	N/A	N/A	N/A	8,760 hrs/yr	0.0 tpy
	Various Laboratory Fume Hoods	N/A	N/A	N/A	N/A	8,760 hrs/yr	0.0 tpy
	Power Plant Field-Erected Tank	Diesel	N/A	N/A	212,120 gallons	8,760 hrs/yr	0.0 tpy
	Ash Bin Vent filter	N/A	N/A	N/A	N/A	8,760 hrs/yr	0.0 tpy
	Ash Vacuum Pump Filter	N/A	N/A	N/A	N/A	8,760 hrs/yr	0.0 tpy
	Ash Loadout to Truck	N/A	N/A	N/A	N/A	8,225 tpy ash	0.0 tpy
	SRC Pellet Stove	Wood Pellets	AP-42 Table 1.10-1	52.2 lb/ton	5.0 lb/hr	8,760 hrs/yr	0.6 tpy
						Insignificant Emission Units Total Assessable Potential to Emit Emissions - CO	**1.7 tpy**
						Total Assessable Potential to Emit Emissions - CO	**399.4 tpy**

Notes:

[1] Maximum annual operation for all units based on full-time operation, or permit operating limits, where applicable.

[2] Conversion factors:

Diesel Heating Value	0.137	MMBtu/gal
Coal Heating Value	15.3	MMBtu/ton
Propane Heating Value	91.5	MMBtu/kgal
Natural Gas Heat Content	1,000	Btu/scf
Engine horsepower	1.341	kW
Assumed drive shaft efficiency for engines	95%	Per Alan Schuler at ADEC
Mass conversion	454.0	g/lb
Engine Heat Rate	7,000	Btu/hp-hr

[3] New emergency stationary internal combustion engines are limited to maintenance checks and readiness testing to no more than 100 hours per year, per 40 CFR 60.4211(f).

[4] Emission factor for small pottery-firing wood-fired kilns are not available. Calculation assumes that combustion of wood in the kilns is similar to that in dry wood-fired boilers.

[5] Approximate heat value of wood combusted in kilns is 15 MMBtu/cord, per http://www.hrt.msu.edu/energy/pdf/heating%20value%20of%20common%20fuels.pdf

[6] Emission factors for propane-fired turbine are not available. Emission factors for natural gas-fired turbine are used.

[7] The higher potential emissions for natural gas or distillate firing is shown as the potential emissions for EU 3.

[8] The highest potential emissions for EU 4 and EU 8 is shown as the potential emissions.

[9] UAF is proposing an operating limit for EU 9A to avoid HAP major classification. Details are provided in Section 4 of this application.

[10] UAF is proposing operating limits for EU 19 through EU 21 to avoid minor permitting requirements for NO_X. Details are provided in Section 4 of this application.

[11] UAF is proposing an operating limit for EU 23 to avoid minor permitting requirements for NO_X. Details are provided in Section 4 of this application.

[12] UAF is proposing an operating limit for EU 25 to avoid PSD permitting requirements for SO_2. Details are provided in Section 4 of this application.

[13] UAF is proposing an operating limit for EU 26 to avoid PSD permitting requirements for NO_X. Details are provided in Section 4 of this application.

[14] Owner-requested limit of 4,380 hr/yr per AQ0316MSS03, currently being prepared by ADEC.

[15] Basis for EU 28 PTE calculated with 100 hr/yr: historical data indicating that engine operates approximately 13 hr/yr. A PTE basis of 100 hr/yr is conservatively high.

[16] Basis for EU 24 PTE calculated with 100 hr/yr. A PTE basis of 100 hr/yr is conservatively high; this engine is operated infrequently.

[17] Basis for EU 26 PTE calculated with 99 hr/yr. This engine is operated approximately 6 hours per year and is considered "limited use" under 40 CFR 63 Subpart ZZZZ.

[18] Maximum annual operation of EU 4 assumes 40 tpy NO_X limit is consumed by EU 4.

Table 2-6. Assessable Potential to Emit Calculations - Particulate Matter Less Than 10 Microns (PM_{10}) Emissions
University of Alaska Fairbanks Campus

Emission Unit ID	Emission Unit Description	Fuel Type	PM_{10} Emission Factor Reference	PM_{10} Emission Factor	Maximum Rating/Capacity	Allowable Annual Operation[1]	Potential PM_{10} Emissions[2]
Significant Emission Units							
1	Coal-Fired Boiler	Coal	November 2010 Source Test	0.65 lb/ton[4]	84.5 MMBtu/hr	8,760 hrs/yr	15.7 tpy
2	Coal-Fired Boiler	Coal	November 2010 Source Test	1.35 lb/ton[4]	84.5 MMBtu/hr	8,760 hrs/yr	32.7 tpy
3	Dual-Fired Boiler	Diesel	AP-42 Tables 1.3-1, 1.3-2	3.3 lb/kgal	180.9 MMBtu/hr	8,760 hrs/yr	19.1 tpy[9]
3	Dual-Fired Boiler	Natural Gas	AP-42 Table 1.4-2	7.6 lb/MMscf	180.9 MMBtu/hr	8,760 hrs/yr	
~~6~~	~~Arctic Health Research Bldg. Emergency Generator~~	~~Diesel~~	~~AP-42 Table 3.3-1~~	~~2.20E-03 lb/hp-hr~~	~~125 kW~~	~~0 hrs/yr~~	0.0 tpy
~~7~~	~~Arctic Health Research Bldg. Emergency Generator~~	~~Diesel~~	~~AP-42 Table 3.3-1~~	~~2.20E-03 lb/hp-hr~~	~~125 kW~~	~~0 hrs/yr~~	0.0 tpy
4	Dual-Fired Boiler	Diesel	AP-42 Tables 1.3-1, 1.3-2	3.3 lb/kgal	180.9 MMBtu/hr	3,333 kgal/yr[21]	9.6 tpy[10]
4	Dual-Fired Boiler	Natural Gas	AP-42 Table 1.4-2	7.6 lb/MMscf	180.9 MMBtu/hr	571 MMscf/yr[21]	
8	Peaking/Backup Generator (DEG) Engine	Diesel	AP-42 Table 3.4-1	7.00E-04 lb/hp-hr	13,266 hp	1,403,509 gal/yr	
9A	BiRD Incinerator	Medical/Infectious Waste	AP-42 Table 2.3-2	4.7 lb/ton	83 lb/hr	109 ton/yr[11]	0.3 tpy
10	AFES Boiler	Diesel	AP-42 Tables 1.3-1, 1.3-2	3.3 lb/kgal	1.08 MMBtu/hr	8,760 hrs/yr	0.11 tpy
11	AFES Boiler	Diesel	AP-42 Tables 1.3-1, 1.3-2	3.3 lb/kgal	1.08 MMBtu/hr	8,760 hrs/yr	0.11 tpy
12	Harper Boiler #1	Diesel	AP-42 Tables 1.3-1, 1.3-2	3.3 lb/kgal	0.64 MMBtu/hr	8,760 hrs/yr	0.07 tpy
13	Harper Boiler #2	Diesel	AP-42 Tables 1.3-1, 1.3-2	3.3 lb/kgal	0.64 MMBtu/hr	8,760 hrs/yr	0.07 tpy
14	Copper Lane Boiler	Diesel	AP-42 Tables 1.3-1, 1.3-2	3.3 lb/kgal	0.136 MMBtu/hr	8,760 hrs/yr	0.01 tpy
15	Copper Lane Boiler	Diesel	AP-42 Tables 1.3-1, 1.3-2	3.3 lb/kgal	0.136 MMBtu/hr	8,760 hrs/yr	0.01 tpy
16	Copper Lane (Honor's House) Boiler	Diesel	AP-42 Tables 1.3-1, 1.3-2	3.3 lb/kgal	0.233 MMBtu/hr	8,760 hrs/yr	0.02 tpy
17	West Ridge Research Building Boiler #1	Diesel	AP-42 Tables 1.3-1, 1.3-2	3.3 lb/kgal	4.93 MMBtu/hr	8,760 hrs/yr	0.52 tpy
18	West Ridge Research Building Boiler #2	Diesel	AP-42 Tables 1.3-1, 1.3-2	3.3 lb/kgal	4.93 MMBtu/hr	8,760 hrs/yr	0.52 tpy
19	BiRD RM 100U3 Boiler #1	Diesel	AP-42 Tables 1.3-1, 1.3-2	3.3 lb/kgal	6.13 MMBtu/hr	19,650 hrs/yr[12]	1.45 tpy
20	BiRD RM 100U3 Boiler #2	Diesel	AP-42 Tables 1.3-1, 1.3-2	3.3 lb/kgal	6.13 MMBtu/hr		
21	BiRD RM 100U3 Boiler #3	Diesel	AP-42 Tables 1.3-1, 1.3-2	3.3 lb/kgal	6.13 MMBtu/hr		
22	BiRD RM 100U3 Boiler #4	Diesel	AP-42 Tables 1.3-1, 1.3-2	3.3 lb/kgal	8.5 MMBtu/hr	8,760 hrs/yr	0.90 tpy
23	Alaska Center for Energy and Power Generator Engine	Diesel	Vendor Data	8.1 g/hr	235 kW	4,380 hrs/yr[13]	0.04 tpy
24	Old University Park Emergency Generator Engine	Diesel	AP-42 Table 3.3-1	2.20E-03 lb/hp-hr	51 kW	100 hrs/yr[19]	0.01 tpy
25	AFES Grain Dryer	Diesel	AP-42 Tables 1.3-1, 1.3-2	3.3 lb/kgal	2.427 MMBtu/hr	100 hrs/yr[14]	2.9E-03 tpy
26	Duckering Classroom Engine	Diesel	AP-42 Table 3.3-1	2.20E-03 lb/hp-hr	45 kW	99 hrs/yr[15,20]	0.01 tpy
27	Alaska Center for Energy and Power Generator Engine	Diesel	Vendor Data	0.12 lb/hr	500 hp	4,380 hrs/yr[17]	0.26 tpy
28	Alaska Earthquake Information Center Emergency Generator Engine	Diesel	AP-42 Table 3.3-1	2.20E-03 lb/hp-hr	120 hp	100 hrs/yr[18]	0.01 tpy
29	Arctic Health Research Emergency Generator Engine	Diesel	EPA Tier 4i	0.02 g/kW-hr	314 hp	100 hrs/yr[3]	0.001 tpy
Significant Emission Units Total Assessable Potential to Emit Emissions - PM_{10}							**81.5 tpy**

Emission Unit		Fuel Type	PM$_{10}$ Emission Factor		Maximum Rating/Capacity	Allowable Annual Operation[1]	Potential PM$_{10}$ Emissions[2]
ID	Description		Reference	Factor			
			Insignificant Emission Units				
30	AFES Greenhouse Furnace	Diesel	AP-42 Tables 1.3-1, 1.3-2	3.3 lb/kgal	0.209 MMBtu/hr	8,760 hrs/yr	0.02 tpy
31	Copper Lane Furnace	Diesel	AP-42 Tables 1.3-1, 1.3-2	3.3 lb/kgal	0.080 MMBtu/hr	8,760 hrs/yr	0.01 tpy
32	Skarland Cabin Furnace	Diesel	AP-42 Tables 1.3-1, 1.3-2	3.3 lb/kgal	0.140 MMBtu/hr	8,760 hrs/yr	0.01 tpy
33	Harper Hot Water Heater	Diesel	AP-42 Tables 1.3-1, 1.3-2	3.3 lb/kgal	0.236 MMBtu/hr	8,760 hrs/yr	0.02 tpy
	Coal Handling/Coal Crushing	Coal	See detailed calculations in Table 2-6b				0.41 tpy
	Various Propane-Fired Kilns	Propane	AP-42 Table 1.5-1	0.7 lb/kgal	2.6 MMBtu/hr, total	8,760 hrs/yr	0.09 tpy
	Wood-Fired Kilns	Wood	AP-42 Table 1.6-2	0.36 lb/MMBtu[5]	Unknown	1 cord/yr[6]	2.7E-03 tpy
	Duckering Classroom Turbine	Propane	AP-42 Table 3.1-2a	6.6E-03 lb/MMBtu[7]	0.33 MMBtu/hr	8,760 hrs/yr	0.01 tpy
	Graduation Flame	Propane	AP-42 Table 13.5-1	0.0 lb/MMBtu[8]	5.0E-03 MMBtu/hr	8,760 hrs/yr	0.0 tpy
	Facilities Services Paint Booth Exhaust Fan	Various Paints	N/A	70% capture	Unknown	131 gal/yr	0.14 tpy[16]
	Museum Paint Booth Exhaust Fan	Various Paints	N/A	N/A	N/A	8,760 hrs/yr	0.0 tpy
	Various Laboratory Fume Hoods	N/A	N/A	N/A	N/A	8,760 hrs/yr	0.0 tpy
	Power Plant Field-Erected Tank	Diesel	N/A	N/A	212,120 gallons	8,760 hrs/yr	0.0 tpy
	Ash Bin Vent filter	N/A	See detailed calculations in Table 2-6a				0.35 tpy
	Ash Vacuum Pump Filter	N/A	See detailed calculations in Table 2-6a				0.43 tpy
	Ash Loadout to Truck	N/A	See detailed calculations in Table 2-6a				1.3E-04 tpy
	SRC Pellet Stove	Wood Pellets	AP-42 Table 1.10-1	8.8 lb/ton	5.0 lb/hr	8,760 hrs/yr	0.1 tpy
						Insignificant Emission Units Total Assessable Potential to Emit Emissions - PM$_{10}$	**1.6 tpy**
						Total Assessable Potential to Emit Emissions - PM$_{10}$	**83.1 tpy**

Notes:

[1] Maximum annual operation for all units based on full-time operation, or permit operating limits, where applicable.

[2] Conversion factors:

Assumed drive shaft efficiency for engines (Per Alan Schuler at ADEC)	95%	Diesel Heating Value	0.137 MMBtu/gal	Propane Heating Value	91.5 MMBtu/kgal
		Coal Heating Value	15.3 MMBtu/ton	Natural Gas Heat Content	1,000 Btu/scf
		Mass conversion	454.0 g/lb	Engine horsepower	1.341 kW
		Engine Heat Rate	7,000 Btu/hp-hr		

[3] New emergency stationary internal combustion engines are limited to maintenance checks and readiness testing to no more than 100 hours per year, per 40 CFR 60.4211(f).

[4] November 2010 source test emission factors reflect *maximum* Total PM emission rates for each coal boiler.

[5] Emission factor for small pottery-firing wood-fired kilns are not available. Calculation assumes that combustion of wood in the kilns is similar to that in dry wood-fired boilers.

[6] Approximate heat value of wood combusted in kilns is 15 MMBtu/cord, per http://www.hrt.msu.edu/energy/pdf/heating%20value%20of%20common%20fuels.pdf

[7] Emission factors for propane-fired turbine are not available. Emission factors for natural gas-fired turbine are used.

[8] The graduation flame is best described as a non-smoking flare. Soot emissions are zero.

[9] The higher potential emissions for natural gas or distillate firing is shown as the potential emissions for EU 3.

[10] The highest potential emissions for EU 4 and EU 8 is shown as the potential emissions.

[11] UAF is proposing an operating limit for EU 9A to avoid HAP major classification. Details are provided in Section 4 of this application.

[12] UAF is proposing operating limits for EU 19 through EU 21 to avoid minor permitting requirements for NO_X. Details are provided in Section 4 of this application.

[13] UAF is proposing an operating limit for EU 23 to avoid minor permitting requirements for NO_X. Details are provided in Section 4 of this application.

[14] UAF is proposing an operating limit for EU 25 to avoid PSD permitting requirements for SO_2. Details are provided in Section 4 of this application.

[15] UAF is proposing an operating limit for EU 26 to avoid PSD permitting requirements for NO_X. Details are provided in Section 4 of this application.

[16] Less than 131 gallons of paint are used on an annual basis in the facilities services paint booth. The density of paint is approximately 7 lb/gal. The facilities services paint booth has fiberglass paint arrestor pads. The calculation conservatively assumes that the entire volume of paint used is emitted as PM. Vendor data for the filters indicates an 70% capture efficiency for particles of 2.5 microns or greater.

[17] Owner-requested limit of 4,380 hr/yr per AQ0316MSS03, currently being prepared by ADEC.

[18] Basis for EU 28 PTE calculated with 100 hr/yr: historical data indicating that engine operates approximately 13 hr/yr. A PTE basis of 100 hr/yr is conservatively high.

[19] Basis for EU 24 PTE calculated with 100 hr/yr. A PTE basis of 100 hr/yr is conservatively high; this engine is operated infrequently.

[20] Basis for EU 26 PTE calculated with 99 hr/yr. This engine is operated approximately 6 hours per year and is considered "limited use" under 40 CFR 63 Subpart ZZZZ.

[21] Maximum annual operation of EU 4 assumes 40 tpy NO_X limit is consumed by EU 4.

Table 2-6a. Assessable Potential to Emit Calculations - Ash Handling System PM_{10} Potential Emission
University of Alaska Fairbanks Campus

Emission Unit		Maximum Rating/Capacity	PM_{10} Emission Factor		Allowable Annual Operation	Potential PM_{10} Emissions
Permit ID	Description		Reference	Factor		
N/A	Ash Bin Vent filter	680 acfm	Vendor PM_{10} filter emission rating	0.02 gr/dscf	8,760 hr/yr	0.35 tpy
N/A	Ash vacuum pump filter	1,500 acfm	Vendor PM_{10} filter emission rating	0.02 gr/dscf	8,760 hr/yr	0.43 tpy
N/A	Ash Loadout to Truck	N/A	AP-42, Section 13.2.4	3.24E-05 lb/ton	8,225 tpy	1.33E-04 tpy

Notes:

1. Ash bin vent filter and ash vacuum pump filter emission calculations:

   (exhaust rate, acfm) x (Temp at STP/Temp of exhaust) x (PM_{10} exhaust concentration, gr/dscf) x (1 lb/ 7,000 gr) x (1 ton/ 2,000 lb) x (60 min/hr) x (operation, hr/yr)

   Temperature at standard conditions = 68 degrees Fahrenheight
   Exhaust temperature of ash bin vent filter = 100 degrees Fahrenheight (estimated)
   Exhaust temperature of fan duct blower/bag filte 180 degrees Fahrenheight (estimated)

2. Ash loadout emission calculations:

   Emission factor from AP-42, Section 13.2.4 based on empirical equation E = k x 0.0032 x (U/5)1.3/(M/2)1.4 lb/ton transferred where:
   k = 0.35 for PM_{10}
   U = mean wind speed = 5.4 mph in Fairbanks, per National Climactic Data Center (http://lwf.ncdc.noaa.gov/oa/climate/online/ccd/avgwind.html)
   M = ash moisture content = 27 percent (AP-42, Table 13.2.4-1)

   Ash loadout emissions based on maximum boiler (EU 1-2) total coal consumption capacity of 96,761 tpy
   Ash content of coal = 8.5% per Usibelli Coal Mine website
   Operations, ash tons/yr = (Σ coal capacity, hr/yr) x (0.085 ash content)
   Ash loadout emissions, tons/yr = (emission factor, lb/ton) x (ash loading, ton/yr) / (2,000 lb/ton)

Table 2-6b. Assessable Potential to Emit Calculations - Coal Handling System PM_{10} Potential Emission
University of Alaska Fairbanks Campus

Emission Source		PM_{10} Emission Factor		Material Handling[2] (tpy)	Control Method	Control Efficiency (percent)	Potential PM_{10} Emissions
Identification	**Type**	**Reference[1]**	**Factor**				
Railcar unloading through grate into crusher	Point	AP-42, Section 13.2.4	3.63E-04 lb/ton	96,761	Plant Building	0	0.02 tpy
Crusher	Point	3-05-010-10, FIRE[3]	0.006 lb/ton	96,761	Plant Building	0	0.29 tpy
Crusher to conveyor 1	Point	AP-42, Section 13.2.4	3.63E-04 lb/ton	96,761	Plant Building	0	0.02 tpy
Conveyor 1 to bucket elevator	Point	AP-42, Section 13.2.4	3.63E-04 lb/ton	96,761	Plant Building	0	0.02 tpy
Bucket elevator to screw conveyor	Point	AP-42, Section 13.2.4	3.63E-04 lb/ton	96,761	Plant Building	0	0.02 tpy
Screw conveyor to coal bin 1 or[4]	Point	AP-42, Section 13.2.4	3.63E-04 lb/ton	48,380	Plant Building	0	0.01 tpy
Screw conveyor to coal bin 2	Point	AP-42, Section 13.2.4	3.63E-04 lb/ton	48,380	Plant Building	0	0.01 tpy
Coal bin 1 to scale 1 or[4]	Point	AP-42, Section 13.2.4	3.63E-04 lb/ton	48,380	Plant Building	0	0.01 tpy
Coal bin 2 to scale 2	Point	AP-42, Section 13.2.4	3.63E-04 lb/ton	48,380	Plant Building	0	0.01 tpy
Scale 1 to boiler 1 or[4]	Point	AP-42, Section 13.2.4	3.63E-04 lb/ton	48,380	Plant Building	0	0.01 tpy
Scale 2 to boiler 2	Point	AP-42, Section 13.2.4	3.63E-04 lb/ton	48,380	Plant Building	0	0.01 tpy
Total Potential PM_{10} Emissions from Coal Preparation Plant							**0.41 tpy**

Notes:

[1]Coal transfer emission factor from AP-42, Section 13.2.4 based on empirical equation $E = k \times 0.0032 \times (U/5)^{1.3}/(M/2)^{1.4}$ lb/ton transferred where:

$k = 0.35$ for PM_{10}

U = mean wind speed = 5.4 mph per http://lwf.ncdc.noaa.gov/oa/climate/online/ccd/avgwind.html

M = coal moisture content = 4.8 percent

[2]Emissions based on maximum boiler (EU 1-2) total capacity of 96,761 tons per year

[3]FIRE = Factor Information Retrieval Data System.

[4]Coal bins are alternately loaded so half the annual coal material throughput (48,380 tpy) is sent to each side of the process because they are identical and in parallel.

Table 2-6c. Assessable Potential to Emit Calculations - Particulate Matter Less Than 2.5 Microns ($PM_{2.5}$) Emissions
University of Alaska Fairbanks Campus

Emission Unit ID	Emission Unit Description	Fuel Type	$PM_{2.5}$ Emission Factor Reference	$PM_{2.5}$ Emission Factor	Maximum Rating/Capacity	Allowable Annual Operation[1]	Potential $PM_{2.5}$ Emissions[2]
			Significant Emission Units				
1	Coal-Fired Boiler	Coal	November 2010 Source Test	0.3 lb/ton[4]	84.5 MMBtu/hr	8,760 hrs/yr	7.3 tpy
2	Coal-Fired Boiler	Coal	November 2010 Source Test	0.3 lb/ton[4]	84.5 MMBtu/hr	8,760 hrs/yr	7.3 tpy
3	Dual-Fired Boiler	Diesel	AP-42 Tables 1.3-2, 1.3-7	2.13 lb/kgal	180.9 MMBtu/hr	8,760 hrs/yr	12.3 tpy[10]
3	Dual-Fired Boiler	Natural Gas	AP-42 Table 1.4-2	7.6 lb/MMscf	180.9 MMBtu/hr	8,760 hrs/yr	
~~6~~	~~Arctic Health Research Bldg. Emergency Generator~~	~~Diesel~~	~~AP-42 Table 3.3-1~~	~~2.20E-03 lb/hp-hr~~	~~125 kW~~	~~0 hrs/yr~~	0.0 tpy
~~7~~	~~Arctic Health Research Bldg. Emergency Generator~~	~~Diesel~~	~~AP-42 Table 3.3-1~~	~~2.20E-03 lb/hp-hr~~	~~125 kW~~	~~0 hrs/yr~~	0.0 tpy
4	Dual-Fired Boiler	Diesel	AP-42 Tables 1.3-2, 1.3-7	2.13 lb/kgal	180.9 MMBtu/hr	3,333 kgal/yr	9.6 tpy[11]
4	Dual-Fired Boiler	Natural Gas	AP-42 Table 1.4-2	7.6 lb/MMscf	180.9 MMBtu/hr	571 MMscf/yr	
8	Peaking/Backup Generator (DEG) Engine	Diesel	AP-42 Table 3.4-1	7.00E-04 lb/hp-hr	13,266 hp	1,403,509 gal/yr	
9A	BiRD Incinerator	Medical/Infectious Waste	AP-42 Table 2.3-2	4.7 lb/ton	83 lb/hr	109 ton/yr[12]	0.3 tpy
10	AFES Boiler	Diesel	AP-42 Tables 1.3-2, 1.3-7	2.13 lb/kgal	1.08 MMBtu/hr	8,760 hrs/yr	0.07 tpy
11	AFES Boiler	Diesel	AP-42 Tables 1.3-2, 1.3-7	2.13 lb/kgal	1.08 MMBtu/hr	8,760 hrs/yr	0.07 tpy
12	Harper Boiler #1	Diesel	AP-42 Tables 1.3-2, 1.3-7	2.13 lb/kgal	0.64 MMBtu/hr	8,760 hrs/yr	0.04 tpy
13	Harper Boiler #2	Diesel	AP-42 Tables 1.3-2, 1.3-7	2.13 lb/kgal	0.64 MMBtu/hr	8,760 hrs/yr	0.04 tpy
14	Copper Lane Boiler	Diesel	AP-42 Tables 1.3-2, 1.3-7	2.13 lb/kgal	0.136 MMBtu/hr	8,760 hrs/yr	0.01 tpy
15	Copper Lane Boiler	Diesel	AP-42 Tables 1.3-2, 1.3-7	2.13 lb/kgal	0.136 MMBtu/hr	8,760 hrs/yr	0.01 tpy
16	Copper Lane (Honor's House) Boiler	Diesel	AP-42 Tables 1.3-2, 1.3-7	2.13 lb/kgal	0.233 MMBtu/hr	8,760 hrs/yr	0.02 tpy
17	West Ridge Research Building Boiler #1	Diesel	AP-42 Tables 1.3-2, 1.3-7	2.13 lb/kgal	4.93 MMBtu/hr	8,760 hrs/yr	0.34 tpy
18	West Ridge Research Building Boiler #2	Diesel	AP-42 Tables 1.3-2, 1.3-7	2.13 lb/kgal	4.93 MMBtu/hr	8,760 hrs/yr	0.34 tpy
19	BiRD RM 100U3 Boiler #1	Diesel	AP-42 Tables 1.3-2, 1.3-7	2.13 lb/kgal	6.13 MMBtu/hr	19,650 hrs/yr[13]	0.94 tpy
20	BiRD RM 100U3 Boiler #2	Diesel	AP-42 Tables 1.3-2, 1.3-7	2.13 lb/kgal	6.13 MMBtu/hr		
21	BiRD RM 100U3 Boiler #3	Diesel	AP-42 Tables 1.3-2, 1.3-7	2.13 lb/kgal	6.13 MMBtu/hr		
22	BiRD RM 100U3 Boiler #4	Diesel	AP-42 Tables 1.3-2, 1.3-7	2.13 lb/kgal	8.5 MMBtu/hr	8,760 hrs/yr	0.58 tpy
23	Alaska Center for Energy and Power Generator Engine	Diesel	Vendor Data	8.1 g/hr	235 kW	4,380 hrs/yr[14]	0.04 tpy
24	Old University Park Emergency Generator Engine	Diesel	AP-42 Table 3.3-1	2.20E-03 lb/hp-hr	51 kW	100 hrs/yr[20]	0.01 tpy
25	AFES Grain Dryer	Diesel	AP-42 Tables 1.3-2, 1.3-7	2.13 lb/kgal	2.427 MMBtu/hr	100 hrs/yr[15]	0.00 tpy
26	Duckering Classroom Engine	Diesel	AP-42 Table 3.3-1	2.20E-03 lb/hp-hr	45 kW	99 hrs/yr[16,21]	0.01 tpy
27	Alaska Center for Energy and Power Generator Engine	Diesel	Vendor Data	0.12 lb/hr	500 hp	4,380 hrs/yr[18]	0.26 tpy
28	Alaska Earthquake Information Center Emergency Generator Engine	Diesel	AP-42 Table 3.3-1	2.20E-03 lb/hp-hr	120 hp	100 hrs/yr[19]	0.01 tpy
29	Arctic Health Research Emergency Generator Engine	Diesel	EPA Tier 4i	0.02 g/kW-hr	314 hp	100 hrs/yr[3]	0.001 tpy
						Significant Emission Units Total Assessable Potential to Emit Emissions - $PM_{2.5}$	**39.5 tpy**

Emission Unit		Fuel Type	PM$_{2.5}$ Emission Factor		Maximum Rating/Capacity	Allowable Annual Operation[1]	Potential PM$_{2.5}$ Emissions[2]
ID	Description		Reference	Factor			
			Insignificant Emission Units				
30	AFES Greenhouse Furnace	Diesel	AP-42 Tables 1.3-2, 1.3-7	2.13 lb/kgal	0.209 MMBtu/hr	8,760 hrs/yr	0.01 tpy
31	Copper Lane Furnace	Diesel	AP-42 Tables 1.3-2, 1.3-7	2.13 lb/kgal	0.080 MMBtu/hr	8,760 hrs/yr	0.01 tpy
32	Skarland Cabin Furnace	Diesel	AP-42 Tables 1.3-2, 1.3-7	2.13 lb/kgal	0.140 MMBtu/hr	8,760 hrs/yr	0.01 tpy
33	Harper Hot Water Heater	Diesel	AP-42 Tables 1.3-2, 1.3-7	2.13 lb/kgal	0.236 MMBtu/hr	8,760 hrs/yr	0.02 tpy
	Coal Handling/Coal Crushing	Coal	See detailed calculations in Table 2-6b		96,761 tpy coal	8,760 hrs/yr	0.41 tpy
	Various Propane-Fired Kilns	Propane	AP-42 Table 1.5-1	0.7 lb/kgal	2.6 MMBtu/hr, total	8,760 hrs/yr	0.09 tpy
	Wood-Fired Kilns	Wood	AP-42 Table 1.6-2	0.36 lb/MMBtu[6]	Unknown	1 cord/yr[7]	2.7E-03 tpy
	Duckering Classroom Turbine	Propane	AP-42 Table 3.1-2a	6.6E-03 lb/MMBtu[8]	0.33 MMBtu/hr	8,760 hrs/yr	0.01 tpy
	Graduation Flame	Propane	AP-42 Table 13.5-1	0.0 lb/MMBtu[9]	5.0E-03 MMBtu/hr	8,760 hrs/yr	0.0 tpy
	Facilities Services Paint Booth Exhaust Fan	Various Paints	N/A	70% capture	Unknown	131 gal/yr	0.14 tpy[17]
	Museum Paint Booth Exhaust Fan	Various Paints	N/A	N/A	N/A	8,760 hrs/yr	0.0 tpy
	Various Laboratory Fume Hoods	N/A	N/A	N/A	N/A	8,760 hrs/yr	0.0 tpy
	Power Plant Field-Erected Tank	Diesel	N/A	N/A	212,120 gallons	8,760 hrs/yr	0.0 tpy
	Ash Bin Vent filter	N/A	See detailed calculations in Table 2-6a				0.35 tpy
	Ash Vacuum Pump Filter	N/A	See detailed calculations in Table 2-6a				0.43 tpy
	Ash Loadout to Truck	N/A	See detailed calculations in Table 2-6a				1.3E-04 tpy
	SRC Pellet Stove	Wood Pellets	AP-42 Table 1.10-1	8.8 lb/ton	5.0 lb/hr	8,760 hrs/yr	0.1 tpy
						Insignificant Emission Units Total Assessable Potential to Emit Emissions - PM$_{2.5}$	**1.6 tpy**
						Total Assessable Potential to Emit Emissions - PM$_{2.5}$	**41.1 tpy[5]**

Notes:

[1] Maximum annual operation for all units based on full-time operation, or permit operating limits, where applicable.

[2] Conversion factors:

Mass conversion	454.0 g/lb		
Diesel Heating Value	0.137 MMBtu/gal	Propane Heating Value	91.5 MMBtu/kgal
Coal Heating Value	15.3 MMBtu/ton	Natural Gas Heat Content	1,000 Btu/scf
Assumed drive shaft efficiency for engines (Per Alan Schuler at ADEC)	95%	Engine horsepower	1.341 kW
Engine Heat Rate	7,000 Btu/hp-hr		

[3] New emergency stationary internal combustion engines are limited to maintenance checks and readiness testing to no more than 100 hours per year, per 40 CFR 60.4211(f).

[4] November 2010 source test emission factor reflects average PM$_{2.5}$ emission rate for both boilers.

[5] PM$_{2.5}$ potential to emit calculations for all emission units other than the coal-fired boilers (EU ID 1 and 2) conservatively assume that PM$_{2.5}$ emissions are equal to PM$_{10}$ emissions.

[6] Emission factor for small pottery-firing wood-fired kilns are not available. Calculation assumes that combustion of wood in the kilns is similar to that in dry wood-fired boilers.

[7] Approximate heat value of wood combusted in kilns is 15 MMBtu/cord, per http://www.hrt.msu.edu/energy/pdf/heating%20value%20of%20common%20fuels.pdf

[8] Emission factors for propane-fired turbine are not available. Emission factors for natural gas-fired turbine are used.

[9] The graduation flame is best described as a non-smoking flare. Soot emissions are zero.

[10] The higher potential emissions for natural gas or distillate firing is shown as the potential emissions for EU 3.

[11] The highest potential emissions for EU 4 and EU 8 is shown as the potential emissions.

[12] UAF is proposing an operating limit for EU 9A to avoid HAP major classification. Details are provided in Section 4 of this application.

[13] UAF is proposing operating limits for EU 19 through EU 21 to avoid minor permitting requirements for NO_X. Details are provided in Section 4 of this application.

[14] UAF is proposing an operating limit for EU 23 to avoid minor permitting requirements for NO_X. Details are provided in Section 4 of this application.

[15] UAF is proposing an operating limit for EU 25 to avoid PSD permitting requirements for SO_2. Details are provided in Section 4 of this application.

[16] UAF is proposing an operating limit for EU 26 to avoid PSD permitting requirements for NO_X. Details are provided in Section 4 of this application.

[17] Less than 131 gallons of paint are used on an annual basis in the facilities services paint booth. The density of paint is approximately 7 lb/gal. The facilities services paint booth has fiberglass paint arrestor pads. The calculation

[18] Owner-requested limit of 4,380 hr/yr per AQ0316MSS03, currently being prepared by ADEC.

[19] Basis for EU 28 PTE calculated with 100 hr/yr: historical data indicating that engine operates approximately 13 hr/yr. A PTE basis of 100 hr/yr is conservatively high.

[20] Basis for EU 24 PTE calculated with 100 hr/yr. A PTE basis of 100 hr/yr is conservatively high; this engine is operated infrequently.

[21] Basis for EU 26 PTE calculated with 99 hr/yr. This engine is operated approximately 6 hours per year and is considered "limited use" under 40 CFR 63 Subpart ZZZZ.

Table 2-7. Assessable Potential to Emit Calculations - Volatile Organic Compounds (VOC) Emissions
University of Alaska Fairbanks Campus

Emission Unit ID	Emission Unit Description	Fuel Type	VOC Emission Factor Reference	VOC Emission Factor Factor	Maximum Rating/Capacity	Allowable Annual Operation[1]	Potential VOC Emissions[2]
Significant Emission Units							
1	Coal-Fired Boiler	Coal	AP-42 Table 1.1-19	0.05 lb/ton	84.5 MMBtu/hr	8,760 hrs/yr	1.2 tpy
2	Coal-Fired Boiler	Coal	AP-42 Table 1.1-19	0.05 lb/ton	84.5 MMBtu/hr	8,760 hrs/yr	1.2 tpy
3	Dual-Fired Boiler	Diesel	AP-42 Table 1.3-3	0.34 lb/kgal	180.9 MMBtu/hr	8,760 hrs/yr	4.4 tpy[8]
3	Dual-Fired Boiler	Natural Gas	AP-42 Table 1.4-2	5.5 lb/MMscf	180.9 MMBtu/hr	8,760 hrs/yr	
~~6~~	~~Arctic Health Research Bldg. Emergency Generator~~	~~Diesel~~	~~AP-42 Table 3.3-1~~	~~0.00251 lb/hp-hr~~	~~125 kW~~	~~0 hrs/yr~~	0.0 tpy
~~7~~	~~Arctic Health Research Bldg. Emergency Generator~~	~~Diesel~~	~~AP-42 Table 3.3-1~~	~~0.00251 lb/hp-hr~~	~~125 kW~~	~~0 hrs/yr~~	0.0 tpy
4	Dual-Fired Boiler	Diesel	AP-42 Table 1.3-3	0.34 lb/kgal	180.9 MMBtu/hr	3,333 kgal/yr	9.7 tpy[9]
4	Dual-Fired Boiler	Natural Gas	AP-42 Table 1.4-2	5.5 lb/MMscf	180.9 MMBtu/hr	571 MMscf/yr	
8	Peaking/Backup Generator (DEG) Engine	Diesel	AP-42 Table 3.4-1	7.05E-04 lb/hp-hr	13,266 hp	1,403,509 gal/yr	
9A	BiRD Incinerator	Medical/Infectious Waste	AP-42, Table 2.3-2	2.99E-01 lb/ton	83 lb/hr	109 ton/yr[10]	0.02 tpy
10	AFES Boiler	Diesel	AP-42 Table 1.3-3	0.34 lb/kgal	1.08 MMBtu/hr	8,760 hrs/yr	0.012 tpy
11	AFES Boiler	Diesel	AP-42 Table 1.3-3	0.34 lb/kgal	1.08 MMBtu/hr	8,760 hrs/yr	0.012 tpy
12	Harper Boiler #1	Diesel	AP-42 Table 1.3-3	0.34 lb/kgal	0.64 MMBtu/hr	8,760 hrs/yr	0.007 tpy
13	Harper Boiler #2	Diesel	AP-42 Table 1.3-3	0.34 lb/kgal	0.64 MMBtu/hr	8,760 hrs/yr	0.007 tpy
14	Copper Lane Boiler	Diesel	AP-42 Table 1.3-3	0.34 lb/kgal	0.136 MMBtu/hr	8,760 hrs/yr	0.001 tpy
15	Copper Lane Boiler	Diesel	AP-42 Table 1.3-3	0.34 lb/kgal	0.136 MMBtu/hr	8,760 hrs/yr	0.001 tpy
16	Copper Lane (Honor's House) Boiler	Diesel	AP-42 Table 1.3-3	0.34 lb/kgal	0.233 MMBtu/hr	8,760 hrs/yr	0.003 tpy
17	West Ridge Research Building Boiler #1	Diesel	AP-42 Table 1.3-3	0.34 lb/kgal	4.93 MMBtu/hr	8,760 hrs/yr	0.054 tpy
18	West Ridge Research Building Boiler #2	Diesel	AP-42 Table 1.3-3	0.34 lb/kgal	4.93 MMBtu/hr	8,760 hrs/yr	0.054 tpy
19	BiRD RM 100U3 Boiler #1	Diesel	AP-42 Table 1.3-3	0.34 lb/kgal	6.13 MMBtu/hr	19,650 hrs/yr[11]	0.150 tpy
20	BiRD RM 100U3 Boiler #2	Diesel	AP-42 Table 1.3-3	0.34 lb/kgal	6.13 MMBtu/hr		
21	BiRD RM 100U3 Boiler #3	Diesel	AP-42 Table 1.3-3	0.34 lb/kgal	6.13 MMBtu/hr		
22	BiRD RM 100U3 Boiler #4	Diesel	AP-42 Table 1.3-3	0.34 lb/kgal	8.5 MMBtu/hr	8,760 hrs/yr	0.092 tpy
23	Alaska Center for Energy and Power Generator Engine	Diesel	Vendor Data	23 g/hr	235 kW	4,380 hrs/yr[12]	0.111 tpy
24	Old University Park Emergency Generator Engine	Diesel	AP-42 Table 3.3-1	0.00251 lb/hp-hr	51 kW	100 hrs/yr[18]	0.009 tpy
25	AFES Grain Dryer	Diesel	AP-42 Table 1.3-3	0.34 lb/kgal	2.43 MMBtu/hr	100 hrs/yr[13]	0.0003 tpy
26	Duckering Classroom Engine	Diesel	AP-42 Table 3.3-1	0.00251 lb/hp-hr	45 kW	99 hrs/yr[14,19]	0.01 tpy
27	Alaska Center for Energy and Power Generator Engine	Diesel	Vendor Data	0.21 lb/hr	500 hp	4,380 hrs/yr[16]	0.46 tpy
28	Alaska Earthquake Information Center Emergency Generator Engine	Diesel	AP-42 Table 3.3-1	0.00251 lb/hp-hr	120 hp	100 hrs/yr[17]	0.015 tpy
29	Arctic Health Research Emergency Generator Engine	Diesel	EPA Tier 4i	0.19 g/kW-hr	314 hp	100 hrs/yr[3]	0.005 tpy
Significant Emission Units Total Assessable Potential to Emit Emissions - VOC							**17.5 tpy**

Emission Unit		Fuel Type	VOC Emission Factor		Maximum Rating/Capacity	Allowable Annual Operation[1]	Potential VOC Emissions[2]
ID	Description		Reference	Factor			
Insignificant Emission Units							
30	AFES Greenhouse Furnace	Diesel	AP-42 Table 1.3-3	0.713 lb/kgal	0.209 MMBtu/hr	8,760 hrs/yr	0.012 tpy
31	Copper Lane Furnace	Diesel	AP-42 Table 1.3-3	0.713 lb/kgal	0.08 MMBtu/hr	8,760 hrs/yr	0.002 tpy
32	Skarland Cabin Furnace	Diesel	AP-42 Table 1.3-3	0.713 lb/kgal	0.14 MMBtu/hr	8,760 hrs/yr	0.003 tpy
33	Harper Hot Water Heater	Diesel	AP-42 Table 1.3-3	0.713 lb/kgal	0.236 MMBtu/hr	8,760 hrs/yr	0.005 tpy
	Coal Handling/Coal Crushing	Coal	N/A	N/A	N/A	8,760 hrs/yr	0.0 tpy
	Various Propane-Fired Kilns	Propane	AP-42 Table 1.5-1	1 lb/kgal	2.6 MMBtu/hr, total	8,760 hrs/yr	0.123 tpy
	Wood-Fired Kilns	Wood	AP-42 Table 1.6-2	0.017 lb/MMBtu[4]	Unknown	1 cord/yr[5]	1.3E-04 tpy
	Duckering Classroom Turbine	Propane	AP-42 Table 3.1-2a	2.1E-03 lb/MMBtu[6]	0.33 MMBtu/hr	8,760 hrs/yr	0.003 tpy
	Graduation Flame	Propane	AP-42 Table 13.5-1	0.14 lb/MMBtu	5.0E-03 MMBtu/hr	8,760 hrs/yr	3.1E-03 tpy
	Facilities Services Paint Booth Exhaust Fan	Various Paints	N/A	N/A	Unknown	131 gal/yr	0.46 tpy[7]
	Museum Paint Booth Exhaust Fan	Various Paints	N/A	N/A	Unknown	10 gal/yr	0.035 tpy[7]
	Various Laboratory Fume Hoods	N/A	See detailed calculations in Table 2-8a				2.4 tpy
	Power Plant Field-Erected Tank	Diesel	EPA TANKS[15]	N/A	212,120 gallons	8,760 hrs/yr	9.2E-03 tpy
	Ash Bin Vent filter	N/A	N/A	N/A	N/A	8,760 hrs/yr	0.0 tpy
	Ash Vacuum Pump Filter	N/A	N/A	N/A	N/A	8,760 hrs/yr	0.0 tpy
	Ash Loadout to Truck	N/A	N/A	N/A	N/A	8,225 tpy ash	0.0 tpy
	SRC Pellet Stove	Wood Pellets	AP-42 Table 1.10-1	No data	5.0 lb/hr	8,760 hrs/yr	0.0 tpy
Insignificant Emission Units Total Assessable Potential to Emit Emissions - VOC							**3.1 tpy**
Total Assessable Potential to Emit Emissions - VOC							**20.6 tpy**

Notes:

[1] Maximum annual operation for all units based on full-time operation, or permit operating limits, where applicable.

[2] Conversion factors:

Mass conversion	454.0 g/lb	Propane Heating Value	91.5 MMBtu/kgal
Diesel Heating Value	0.137 MMBtu/gal	Natural Gas Heat Content	1,000 Btu/scf
Coal Heating Value	15.3 MMBtu/ton	Engine horsepower	1.341 kW
Assumed drive shaft efficiency for engines	95% Per Alan Schuler at ADEC		
Engine Heat Rate	7,000 Btu/hp-hr		

[3] New emergency stationary internal combustion engines are limited to maintenance checks and readiness testing to no more than 100 hours per year, per 40 CFR 60.4211(f).

[4] Emission factor for small pottery-firing wood-fired kilns are not available. Calculation assumes that combustion of wood in the kilns is similar to that in dry wood-fired boilers.

[5] Approximate heat value of wood combusted in kilns is 15 MMBtu/cord, per http://www.hrt.msu.edu/energy/pdf/heating%20value%20of%20common%20fuels.pdf

[6] Emission factors for propane-fired turbine are not available. Emission factors for natural gas-fired turbine are used.

[7] Less than 131 gallons of paint are used on an annual basis in the facilities services paint booth. Less than 10 gallons of paint are used on an annual basis in the museum paint booth. The density of paint is approximately 7 lb/gal.

[8] The higher potential emissions for natural gas or distillate firing is shown as the potential emissions for EU 3.

[9] The highest potential emissions for EU 4 and EU 8 is shown as the potential emissions.

[10] UAF is proposing an operating limit for EU 9A to avoid HAP major classification. Details are provided in Section 4 of this application.

[11] UAF is proposing operating limits for EU19 through EU21 to avoid minor permitting requirements for NO_X. Details are provided in Section 4 of this application.

[12] UAF is proposing an operating limit for EU 23 to avoid minor permitting requirements for NO_X. Details are provided in Section 4 of this application.

[13] UAF is proposing an operating limit for EU 25 to avoid PSD permitting requirements for SO_2. Details are provided in Section 4 of this application.

[14] UAF is proposing an operating limit for EU 26 to avoid PSD permitting requirements for NO_X. Details are provided in Section 4 of this application.

[15] See TANKS report in Section 2 of this application.

[16] Owner-requested limit of 4,380 hr/yr per AQ0316MSS03, currently being prepared by ADEC.

[17] Basis for EU 28 PTE calculated with 100 hr/yr: historical data indicating that engine operates approximately 13 hr/yr. A PTE basis of 100 hr/yr is conservatively high.

[18] Basis for EU 24 PTE calculated with 100 hr/yr. A PTE basis of 100 hr/yr is conservatively high; this engine is operated infrequently.

[19] Basis for EU 26 PTE calculated with 99 hr/yr. This engine is operated approximately 6 hours per year and is considered "limited use" under 40 CFR 63 Subpart ZZZZ.

Table 2-7a. Assessable Potential to Emit Calculations - Laboratory Fume Hoods VOC Potential Emission
University of Alaska Fairbanks Campus

Chemical	CAS No.	Amount Stored On-site (liters)	Specific Gravity of Stored Substance	Percent in solution	Amount Stored On-site (lbs)	Potential VOC Emissions (tpy)	HAP Emissions (tpy)
2-Butanone	78-93-3	35	0.806	100	62.2	0.031	
Acetic acid	64-19-7	39	1.05	97	87.5	0.044	
Acetone	67-64-1	495	0.788	100	859.7	0.430	
Benzene	71-43-2	12	0.8765	100	23.2	0.012	0.012
Ethanol	64-17-5	502	0.79	100	874.1	0.437	
Formaldehyde	50-00-0	398	1.08	38	360.0	0.180	0.180
Methyl alcohol in formaldehyde solution	67-56-1			15	142.1	0.071	0.071
Hexane	110-54-3	77	0.659	94	105.1	0.053	0.053
Methanol	67-56-1	443	0.791	100	772.3	0.386	0.386
Methylene chloride	75-09-2	156	1.3266	100	456.1	0.228	0.228
Phenol	108-95-2	4	1.057	100	9.3	0.005	0.005
n-Propyl alcohol and 2-Propanol	71-23-8, 67-63-0	356	0.7945	100	623.4	0.312	
Stoddard solvent	8052-41-3	32	0.787	100	55.5	0.028	
Toluene	108-88-3	178	0.86	100	337.4	0.169	0.169
Xylene	1330-20-7	43	0.864	100	81.9	0.041	0.041
Total Potential VOC Emissions from Laboratory Hoods						**2.42**	**1.14**

Notes:
1. The above chemicals were determined to be common chemicals that contained VOCs.
3. Only chemical inventories of 4 liters or greater were included.
4. This inventory is not up to date, but reflects the most current information available.
5. This inventory does not reflect chemical usage, only those stored on-site.
6. In order to estimate VOC emissions from laboratory hoods, the following assumptions are made:
- The chemicals stored on-site are used within a year.
- The chemicals are emitted in their current form and are 100% volatile.
- The chemicals are not transformed into other chemicals. Other VOCs are not created during laboratory use.
7. Specific gravity and percent of chemical in solution data obtained from chemical product material safety data sheets.

SG of Water	1	kg/L
Conversion	2.204	lb/kg
Conversion	2000	lb/ton

8. Example calculations:

Amount stored on-site (lbs) = (liters stored) x (specific gravity) x (2.204 lb/kg) x (percent in solution)
Emission estimate (ton/yr) = (pounds stored) / (2,000 lb/ton)

Table 2-8. Assessable Potential to Emit Calculations - Sulfur Dioxide (SO_2) Emissions
University of Alaska Fairbanks Campus

Emission Unit ID	Emission Unit Description	Fuel Type	Fuel Sulfur Content[12]	SO_2 Emission Factor Reference	SO_2 Emission Factor Factor	Maximum Rating/Capacity	Allowable Annual Operation[1]	Potential SO_2 Emissions[2]
Significant Emission Units								
1	Coal-Fired Boiler	Coal	0.26 weight %	AP-42 Table 1.1-3	35 *S lb/ton	84.5 MMBtu/hr	8,760 hrs/yr	220.1 tpy
2	Coal-Fired Boiler	Coal	0.26 weight %	AP-42 Table 1.1-3	35 *S lb/ton	84.5 MMBtu/hr	8,760 hrs/yr	220.1 tpy
3	Dual-Fired Boiler	Diesel	0.5 weight %	AP-42 Table 1.3-1	142 *S lb/kgal	180.9 MMBtu/hr	8,760 hrs/yr	410.6 tpy[7]
3	Dual-Fired Boiler	Natural Gas	N/A	AP-42 Table 1.4-2	0.6 lb/MMscf	180.9 MMBtu/hr	8,760 hrs/yr	
~~6~~	~~Arctic Health Research Bldg. Emergency Generator~~	~~Diesel~~	~~0.5 weight %~~	~~Mass Balance~~	~~0.003628 lb/hp-hr~~	~~125 kW~~	~~0 hrs/yr~~	0.0 tpy
~~7~~	~~Arctic Health Research Bldg. Emergency Generator~~	~~Diesel~~	~~0.5 weight %~~	~~Mass Balance~~	~~0.003628 lb/hp-hr~~	~~125 kW~~	~~0 hrs/yr~~	0.0 tpy
4	Dual-Fired Boiler	Diesel	0.0015 weight %[19]	AP-42 Table 1.3-1	142 *S lb/kgal	180.9 MMBtu/hr	3,333 kgal/yr[20]	40.0 tpy[8]
4	Dual-Fired Boiler	Natural Gas	N/A	AP-42 Table 1.4-2	0.6 lb/MMscf	180.9 MMBtu/hr	571 MMscf/yr[20]	
8	Peaking/Backup Generator (DEG) Engine	Diesel	0.5 weight %	AP-42 Table 3.4-1	8.09E-03 *S lb/hp-hr	13,266 hp	1,403,509 gal/yr	
9A	BiRD Incinerator	Medical/Infectious Waste	N/A	AP-42 Table 2.3-1	2.17 lb/ton	83 lb/hr	109 ton/yr[9]	0.1 tpy
10	AFES Boiler	Diesel	0.5 weight %	AP-42 Table 1.3-1	142 *S lb/kgal	1.08 MMBtu/hr	8,760 hrs/yr	2.445 tpy
11	AFES Boiler	Diesel	0.5 weight %	AP-42 Table 1.3-1	142 *S lb/kgal	1.08 MMBtu/hr	8,760 hrs/yr	2.445 tpy
12	Harper Boiler #1	Diesel	0.0015 weight %[12]	AP-42 Table 1.3-1	142 *S lb/kgal	0.64 MMBtu/hr	8,760 hrs/yr	0.004 tpy
13	Harper Boiler #2	Diesel	0.0015 weight %[12]	AP-42 Table 1.3-1	142 *S lb/kgal	0.64 MMBtu/hr	8,760 hrs/yr	0.004 tpy
14	Copper Lane Boiler	Diesel	0.0015 weight %[12]	AP-42 Table 1.3-1	142 *S lb/kgal	0.136 MMBtu/hr	8,760 hrs/yr	0.001 tpy
15	Copper Lane Boiler	Diesel	0.0015 weight %[12]	AP-42 Table 1.3-1	142 *S lb/kgal	0.136 MMBtu/hr	8,760 hrs/yr	0.001 tpy
16	Copper Lane (Honor's House) Boiler	Diesel	0.0015 weight %[12]	AP-42 Table 1.3-1	142 *S lb/kgal	0.233 MMBtu/hr	8,760 hrs/yr	0.002 tpy
17	West Ridge Research Building Boiler #1	Diesel	0.0015 weight %[12]	AP-42 Table 1.3-1	142 *S lb/kgal	4.93 MMBtu/hr	8,760 hrs/yr	0.034 tpy
18	West Ridge Research Building Boiler #2	Diesel	0.0015 weight %[12]	AP-42 Table 1.3-1	142 *S lb/kgal	4.93 MMBtu/hr	8,760 hrs/yr	0.034 tpy
19	BiRD RM 100U3 Boiler #1	Diesel	0.0015 weight %[12]	AP-42 Table 1.3-1	142 *S lb/kgal	6.13 MMBtu/hr	19,650 hrs/yr[10]	0.094 tpy
20	BiRD RM 100U3 Boiler #2	Diesel	0.0015 weight %[12]	AP-42 Table 1.3-1	142 *S lb/kgal	6.13 MMBtu/hr		
21	BiRD RM 100U3 Boiler #3	Diesel	0.0015 weight %[12]	AP-42 Table 1.3-1	142 *S lb/kgal	6.13 MMBtu/hr		
22	BiRD RM 100U3 Boiler #4	Diesel	0.0015 weight %[12]	AP-42 Table 1.3-1	142 *S lb/kgal	8.5 MMBtu/hr	8,760 hrs/yr	0.058 tpy
23	Alaska Center for Energy and Power Generator Engine	Diesel	0.0015 weight %[12]	Mass Balance	1.09E-05 lb/hp-hr	235 kW	4,380 hrs/yr[11]	0.008 tpy
24	Old University Park Emergency Generator Engine	Diesel	0.0015 weight %[12]	Mass Balance	1.09E-05 lb/hp-hr	51 kW	100 hrs/yr[17]	3.9E-05 tpy
25	AFES Grain Dryer	Diesel	0.5 weight %	AP-42 Table 1.3-1	142 *S lb/kgal	2.43 MMBtu/hr	100 hrs/yr[13]	0.063 tpy
26	Duckering Classroom Engine	Diesel	0.0015 weight %[12]	Mass Balance	1.09E-05 lb/hp-hr	45 kW	99 hrs/yr[14,18]	3.4E-05 tpy
27	Alaska Center for Energy and Power Generator Engine	Diesel	0.0015 weight %	Mass Balance	1.09E-05 lb/hp-hr	500 hp	4,380 hrs/yr[15]	0.01 tpy
28	Alaska Earthquake Information Center Emergency Generator Engine	Diesel	0.0015 weight %[12]	Mass Balance	1.09E-05 lb/hp-hr	120 hp	100 hrs/yr[16]	6.5E-05 tpy
29	Arctic Health Research Emergency Generator Engine	Diesel	0.0015 weight %	Mass Balance	0.0027 lb/hr	314 hp	100 hrs/yr[3]	1.4E-04 tpy
Significant Emission Units Total Assessable Potential to Emit Emissions - SO_2								**896.2 tpy**

Emission Unit		Fuel Type	Fuel Sulfur Content[12]	SO_2 Emission Factor		Maximum Rating/Capacity	Allowable Annual Operation[1]	Potential SO_2 Emissions[2]
ID	Description			Reference	Factor			
Insignificant Emission Units								
30	AFES Greenhouse Furnace	Diesel	0.5 weight %	AP-42 Table 1.3-1	142 *S lb/kgal	0.209 MMBtu/hr	8,760 hrs/yr	0.475 tpy
31	Copper Lane Furnace	Diesel	0.5 weight %	AP-42 Table 1.3-1	142 *S lb/kgal	0.08 MMBtu/hr	8,760 hrs/yr	0.182 tpy
32	Skarland Cabin Furnace	Diesel	0.5 weight %	AP-42 Table 1.3-1	142 *S lb/kgal	0.14 MMBtu/hr	8,760 hrs/yr	0.318 tpy
33	Harper Hot Water Heater	Diesel	0.5 weight %	AP-42 Table 1.3-1	142 *S lb/kgal	0.236 MMBtu/hr	8,760 hrs/yr	0.536 tpy
	Coal Handling/Coal Crushing	Coal	N/A	N/A	N/A	N/A	8,760 hrs/yr	0.00 tpy
	Various Propane-Fired Kilns	Propane	0.2 gr/100 ft^3	AP-42 Table 1.5-1	0.1 *S lb/kgal	2.6 MMBtu/hr, total	8,760 hrs/yr	0.002 tpy
	Wood-Fired Kilns	Wood	N/A	AP-42 Table 1.6-2	0.025 lb/MMBtu[4]	Unknown	1 cord/yr[5]	1.9E-04 tpy
	Duckering Classroom Turbine	Propane	2.4E-02 weight %	AP-42 Table 3.1-2a	9.4E-01 *S lb/MMBtu[6]	0.33 MMBtu/hr	8,760 hrs/yr	0.03 tpy
	Graduation Flame	Propane	0.2 gr/100 ft^3	Mass Balance	2.3E-04 lb/MMBtu	5.0E-03 MMBtu/hr	8,760 hrs/yr	5.0E-06 tpy
	Various Paint Booths	N/A	N/A	N/A	N/A	N/A	8,760 hrs/yr	0.00 tpy
	Various Laboratory Fume Hoods	N/A	N/A	N/A	N/A	N/A	8,760 hrs/yr	0.00 tpy
	Power Plant Field-Erected Tank	Diesel	0.5 weight %	N/A	N/A	212,120 gallons	8,760 hrs/yr	0.0 tpy
	Ash Bin Vent filter	N/A	N/A	N/A	N/A	N/A	8,760 hrs/yr	0.00 tpy
	Ash Vacuum Pump Filter	N/A	N/A	N/A	N/A	N/A	8,760 hrs/yr	0.00 tpy
	Ash Loadout to Truck	N/A	N/A	N/A	N/A	N/A	8,225 tpy ash	0.00 tpy
	SRC Pellet Stove	Wood Pellets	N/A	AP-42 Table 1.10-1	0.4 lb/ton	5.0 lb/hr	8,760 hrs/yr	4.4E-03 tpy
Insignificant Emission Units Total Assessable Potential to Emit Emissions - SO_2								1.55 tpy
Total Assessable Potential to Emit Emissions - SO_2								897.8 tpy

Notes:

[1] Maximum annual operation for all units based on full-time operation, or permit operating limits, where applicable.

[2] Conversion factors:

Diesel Heating Value	0.137	MMBtu/gal
Coal Heating Value	15.3	MMBtu/ton
Propane Heating Value	91.5	MMBtu/kgal
Natural Gas Heat Content	1,000	Btu/scf
Density of Diesel	7.1	lb/gal
Engine Heat Rate	7,000	Btu/hp-hr
Engine horsepower	1.341	kW
Assumed drive shaft efficiency for engines	95%	Per Alan Schuler at ADEC

[3] New emergency stationary internal combustion engines are limited to maintenance checks and readiness testing to no more than 100 hours per year, per 40 CFR 60.4211(f).

[4] Emission factor for small pottery-firing wood-fired kilns are not available. Calculation assumes that combustion of wood in the kilns is similar to that in dry wood-fired boilers.

[5] Approximate heat value of wood combusted in kilns is 15 MMBtu/cord, per http://www.hrt.msu.edu/energy/pdf/heating%20value%20of%20common%20fuels.pdf

[6] Emission factors for propane-fired turbine are not available. Emission factors for natural gas-fired turbine are used.

[7] The higher potential emissions for natural gas or distillate firing is shown as the potential emissions for EU 3.

[8] Potential emissions for EU 4 and EU 8 are limited to 40 tpy combined, per Condition 15 of Permit No. AQ0316TVP02.

[9] UAF is proposing an operating limit for EU 9A to avoid HAP major classification. Details are provided in Section 4 of this application.

[10] UAF is proposing operating limits for EU 19 through EU 21 to avoid minor permitting requirements for NO_X. Details are provided in Section 4 of this application.

[11] UAF is proposing an operating limit for EU 23 to avoid minor permitting requirements for NO_X. Details are provided in Section 4 of this application.

[12] UAF is proposing an operating limit requiring the use of ultra-low sulfur diesel for EU 12 through EU 24 to avoid PSD permitting requirements for SO_2. Details are provided in Section 4 of this application.

[13] UAF is proposing an operating limit for EU 25 to avoid PSD permitting requirements for SO_2. Details are provided in Section 4 of this application.

[14] UAF is proposing an operating limit for EU 26 to avoid PSD permitting requirements for NO_X. Details are provided in Section 4 of this application.

[15] Owner-requested limit of 4,380 hr/yr per AQ0316MSS03, currently being prepared by ADEC.

[16] Basis for EU 28 PTE calculated with 100 hr/yr: historical data indicating that engine operates approximately 13 hr/yr. A PTE basis of 100 hr/yr is conservatively high.

[17] Basis for EU 24 PTE calculated with 100 hr/yr. A PTE basis of 100 hr/yr is conservatively high; this engine is operated infrequently.

[18] Basis for EU 26 PTE calculated with 99 hr/yr. This engine is operated approximately 6 hours per year and is considered "limited use" under 40 CFR 63 Subpart ZZZZ.

[19] UAF now uses only ultra low sulfur diesel (ULSD) fuel in EU 4.

[20] Maximum annual operation of EU 4 assumes 40 tpy NO_X limit is consumed by EU 4.

Table 2-9. Summary of Estimated Potential Hazardous Air Pollutants (HAP) Emissions
University of Alaska Fairbanks Campus

Hazardous Air Pollutant	HAP Emissions by Emission Unit Category (tons per year)[1]										Total HAP Emissions
	Storage Tank[2]	Coal-Fired Boilers	Diesel Boilers & Heaters (Except EU 4)	Natural Gas Boiler EU 3	Diesel Engines <=600 hp	EU 4 and EU 8	Waste Incinerators	Laboratory Hoods	Propane-Fired Kilns[3]	Pellet Stove	
Acetaldehyde	----	2.76E-02	----	----	9.72E-03	2.42E-03	----	----	----	----	3.97E-02
Acetamide	----	----	----	----	----	----	----	----	----	----	0.00E+00
Acetonitrile	----	----	----	----	----	----	----	----	----	----	0.00E+00
Acetophenone	----	7.26E-04	----	----	----	----	----	----	----	----	7.26E-04
2-Acetylaminofluorene	----	----	----	----	----	----	----	----	----	----	0.00E+00
Acrolein	----	1.40E-02	----	----	1.17E-03	7.58E-04	----	----	----	----	1.60E-02
Acrylamide	----	----	----	----	----	----	----	----	----	----	0.00E+00
Acrylic Acid	----	----	----	----	----	----	----	----	----	----	0.00E+00
Acrylonitrile	----	----	----	----	----	----	----	----	----	----	0.00E+00
Allyl chloride	----	----	----	----	----	----	----	----	----	----	0.00E+00
4-Aminobiphenyl	----	----	----	----	----	----	----	----	----	----	0.00E+00
Aniline	----	----	----	----	----	----	----	----	----	----	0.00E+00
o-Anisidine	----	----	----	----	----	----	----	----	----	----	0.00E+00
Asbestos	----	----	----	----	----	----	----	----	----	----	0.00E+00
Benzene	----	6.29E-02	1.49E-03	1.66E-03	1.18E-02	7.46E-02	----	1.16E-02	----	----	1.64E-01
Benzidine	----	----	----	----	----	----	----	----	----	----	0.00E+00
Benzotricholoride	----	----	----	----	----	----	----	----	----	----	0.00E+00
Benzyl chloride	----	3.39E-02	----	----	----	----	----	----	----	----	3.39E-02
Biphenyl	----	8.22E-05	----	----	----	----	----	----	----	----	8.22E-05
Bis(2-ethylhexyl)phthalate (DEHP)	----	3.53E-03	----	----	----	----	----	----	----	----	3.53E-03
Bis(chloromethyl)ether	----	----	----	----	----	----	----	----	----	----	0.00E+00
Bromoform	----	1.89E-03	----	----	----	----	----	----	----	----	1.89E-03
1,3 Butadiene	----	----	----	----	4.95E-04	----	----	----	----	----	4.95E-04
Calcium cyanamide	----	----	----	----	----	----	----	----	----	----	0.00E+00
Caprolactam	----	----	----	----	----	----	----	----	----	----	0.00E+00
Captan	----	----	----	----	----	----	----	----	----	----	0.00E+00
Carbaryl	----	----	----	----	----	----	----	----	----	----	0.00E+00
Carbon disulfide	----	6.29E-03	----	----	----	----	----	----	----	----	6.29E-03
Carbon tetrachloride	----	----	----	----	----	----	----	----	----	----	0.00E+00
Carbonyl sufide	----	----	----	----	----	----	----	----	----	----	0.00E+00
Catechol	----	----	----	----	----	----	----	----	----	----	0.00E+00
Chloramben	----	----	----	----	----	----	----	----	----	----	0.00E+00
Chlordane	----	----	----	----	----	----	----	----	----	----	0.00E+00
Chlorine	----	----	----	----	----	----	5.72E-03	----	----	----	5.72E-03
Chloroacetic acid	----	----	----	----	----	----	----	----	----	----	0.00E+00
2-Chloroacetophenone	----	3.39E-04	----	----	----	----	----	----	----	----	3.39E-04
Chlorobenzene	----	1.06E-03	----	----	----	----	----	----	----	----	1.06E-03
Chlorobenzilate	----	----	----	----	----	----	----	----	----	----	0.00E+00
Chloroform	----	2.85E-03	----	----	----	----	----	----	----	----	2.85E-03
Chloromethyl methyl ether	----	----	----	----	----	----	----	----	----	----	0.00E+00
Chloroprene	----	----	----	----	----	----	----	----	----	----	0.00E+00
Cresols/Creshlic acid (isomers and mixture)	----	----	----	----	----	----	----	----	----	----	0.00E+00
o-Cresol	----	----	----	----	----	----	----	----	----	----	0.00E+00
m-Cresol	----	----	----	----	----	----	----	----	----	----	0.00E+00
p-Cresol	----	----	----	----	----	----	----	----	----	----	0.00E+00
Cumene	----	2.56E-04	----	----	----	----	----	----	----	----	2.56E-04
2,4-D, salts and esters	----	----	----	----	----	----	----	----	----	----	0.00E+00
DDE	----	----	----	----	----	----	----	----	----	----	0.00E+00
Diazomethane	----	----	----	----	----	----	----	----	----	----	0.00E+00
Dibenzofurans	----	5.27E-08	----	----	----	----	3.90E-06	----	----	----	3.95E-06
1,2-Dibromo-3-chloropropane	----	----	----	----	----	----	----	----	----	----	0.00E+00
Dibutylphthalate	----	----	----	----	----	----	----	----	----	----	0.00E+00
1,4-Dichlorobenzene(p)	----	----	----	9.51E-04	----	3.43E-04	----	----	----	----	1.29E-03
3,3-Dichlorobenzidene	----	----	----	----	----	----	----	----	----	----	0.00E+00
Dichloroethyl ether(Bis(2-chloroethyl)ether)	----	----	----	----	----	----	----	----	----	----	0.00E+00
1,3-Dichloropropene	----	----	----	----	----	----	----	----	----	----	0.00E+00
Dichlorvos	----	----	----	----	----	----	----	----	----	----	0.00E+00
Diethanolamine	----	----	----	----	----	----	----	----	----	----	0.00E+00
N,N-Diethyl anniline (N,N-Dimethylanine)	----	----	----	----	----	----	----	----	----	----	0.00E+00
Diethyl sulfate	----	----	----	----	----	----	----	----	----	----	0.00E+00
3,3-Dimethoxybenzidine	----	----	----	----	----	----	----	----	----	----	0.00E+00
Dimethyl aminoazobenzene	----	----	----	----	----	----	----	----	----	----	0.00E+00

Hazardous Air Pollutant	HAP Emissions by Emission Unit Category (tons per year)[1]										Total HAP Emissions
	Storage Tank[2]	Coal-Fired Boilers	Diesel Boilers & Heaters (Except EU 4)	Natural Gas Boiler EU 3	Diesel Engines <=600 hp	EU 4 and EU 8	Waste Incinerators	Laboratory Hoods	Propane-Fired Kilns[3]	Pellet Stove	
3,3-Dimethyl benzidine	----	----	----	----	----	----	----	----	----	----	0.00E+00
Dimethyl caramoyl chloride	----	----	----	----	----	----	----	----	----	----	0.00E+00
Dimethyl formamide	----	----	----	----	----	----	----	----	----	----	0.00E+00
1,1-Dimethyl hydrazine	----	----	----	----	----	----	----	----	----	----	0.00E+00
Dimethyl phthalate	----	----	----	----	----	----	----	----	----	----	0.00E+00
Dimethyl sulfate	----	2.32E-03	----	----	----	----	----	----	----	----	2.32E-03
4,6-Dinitro-o-cresol, and salts	----	----	----	----	----	----	----	----	----	----	0.00E+00
2,4-Dinitrophenol	----	----	----	----	----	----	----	----	----	----	0.00E+00
2,4-Dinitrotoluene	----	1.35E-05	----	----	----	----	----	----	----	----	1.35E-05
1,4-Dioxane(1,4-Diethyleneoxide)	----	----	----	----	----	----	----	----	----	----	0.00E+00
1,2-Diphenylhydrazine	----	----	----	----	----	----	----	----	----	----	0.00E+00
Epichlorohydrin (1-Chloro-2,3-epoxypropane)	----	----	----	----	----	----	----	----	----	----	0.00E+00
1,2-Epoxybutane	----	----	----	----	----	----	----	----	----	----	0.00E+00
Ethyl acrylate	----	----	----	----	----	----	----	----	----	----	0.00E+00
Ethyl benzene	----	4.55E-03	4.43E-04	----	----	1.06E-04	----	----	----	----	5.10E-03
Ethyl carbamate (Urethane)	----	----	----	----	----	----	----	----	----	----	0.00E+00
Ethyl chloride (Chloroethane)	----	2.03E-03	----	----	----	----	----	----	----	----	2.03E-03
Ethylene dibromide (Dibromoethane)	----	5.81E-05	----	----	----	----	----	----	----	----	5.81E-05
Ethylene dichloride (1,2-Dichloroethane)	----	1.94E-03	----	----	----	----	----	----	----	----	1.94E-03
Ethylene glycol	----	----	----	----	----	----	----	----	----	----	0.00E+00
Ethylene imine (Aziridine)	----	----	----	----	----	----	----	----	----	----	0.00E+00
Ethylene oxide	----	----	----	----	----	----	----	----	----	----	0.00E+00
Ethylene thiourea	----	----	----	----	----	----	----	----	----	----	0.00E+00
Ethylidene dichloride (1,1-Dichloroethane)	----	----	----	----	----	----	----	----	----	----	0.00E+00
Formaldehyde	----	1.16E-02	2.44E-01	5.96E-02	1.50E-02	5.83E-02	----	1.80E-01	----	----	5.68E-01
Heptachlor	----	----	----	----	----	----	----	----	----	----	0.00E+00
Hexachlorobenzene	----	----	----	----	----	----	----	----	----	----	0.00E+00
Hexachlorobutadiene	----	----	----	----	----	----	----	----	----	----	0.00E+00
Hexachlorocyclopentadiene	----	----	----	----	----	----	----	----	----	----	0.00E+00
Hexachloroethane	----	----	----	----	----	----	----	----	----	----	0.00E+00
Hexamethylene-1,6-diisocyanate	----	----	----	----	----	----	----	----	----	----	0.00E+00
Hexamethylphosphoramide	----	----	----	----	----	----	----	----	----	----	0.00E+00
Hexane	----	3.24E-03	----	1.43E+00	----	5.14E-01	----	5.26E-02	----	----	2.00E+00
Hydrazine	----	----	----	----	----	----	----	----	----	----	0.00E+00
Hydrochloric acid	----	6.68E+00	----	----	----	----	1.83E+00	----	----	----	8.50E+00
Hydrogen fluoride (Hydrofluoric acid)	----	6.72E+00	----	----	----	----	8.12E-03	----	----	----	6.73E+00
Hydroquinone	----	----	----	----	----	----	----	----	----	----	0.00E+00
Isophorone	----	2.81E-02	----	----	----	----	----	----	----	----	2.81E-02
Lindane (all isomers)	----	----	----	----	----	----	----	----	----	----	0.00E+00
Maleic anhydride	----	----	----	----	----	----	----	----	----	----	0.00E+00
Methanol	----	----	----	----	----	----	----	4.57E-01	----	----	4.57E-01
Methoxychlor	----	----	----	----	----	----	----	----	----	----	0.00E+00
Methyl bromide (Bromomethane)	----	7.74E-03	----	----	----	----	----	----	----	----	7.74E-03
Methyl chloride (chloromethane)	----	2.56E-02	----	----	----	----	----	----	----	----	2.56E-02
Methyl chloroform (1,1,1-Trichloroethane)	----	----	----	----	----	----	----	----	----	----	0.00E+00
Methyl hydrazine	----	8.22E-03	----	----	----	----	----	----	----	----	8.22E-03
Methyl iodide (Iodomethane)	----	----	----	----	----	----	----	----	----	----	0.00E+00
Methyl isobutyl ketone (Hexone)	----	----	----	----	----	----	----	----	----	----	0.00E+00
Methyl isocyanate	----	----	----	----	----	----	----	----	----	----	0.00E+00
Methyl methacrylate	----	9.68E-04	----	----	----	----	----	----	----	----	9.68E-04
Methyl tert butyl ether	----	1.69E-03	----	----	----	----	----	----	----	----	1.69E-03
4,4-Methylene bis(2-chloroaniline)	----	----	----	----	----	----	----	----	----	----	0.00E+00
Methylene chloride (Dichloromethane)	----	1.40E-02	----	----	----	----	----	2.28E-01	----	----	2.42E-01
Methylene diphenyl diisocyante (MDI)	----	----	----	----	----	----	----	----	----	----	0.00E+00
4,4'-Methylenedianiline	----	----	----	----	----	----	----	----	----	----	0.00E+00
Nitrobenzene	----	----	----	----	----	----	----	----	----	----	0.00E+00
4-Nitrobiphenyl	----	----	----	----	----	----	----	----	----	----	0.00E+00
4-Nitrophenol	----	----	----	----	----	----	----	----	----	----	0.00E+00
2-Nitropropane	----	----	----	----	----	----	----	----	----	----	0.00E+00
N-Nitroso-N-methylurea	----	----	----	----	----	----	----	----	----	----	0.00E+00

Hazardous Air Pollutant	HAP Emissions by Emission Unit Category (tons per year)[1]										Total HAP Emissions
	Storage Tank[2]	Coal-Fired Boilers	Diesel Boilers & Heaters (Except EU 4)	Natural Gas Boiler EU 3	Diesel Engines <=600 hp	EU 4 and EU 8	Waste Incinerators	Laboratory Hoods	Propane-Fired Kilns[3]	Pellet Stove	
N-Nitrosodimethylamine	----	----	----	----	----	----	----	----	----	----	0.00E+00
N-Nitrosomorpholine	----	----	----	----	----	----	----	----	----	----	0.00E+00
Parathion	----	----	----	----	----	----	----	----	----	----	0.00E+00
Pentachloromitrobenzene (Quintobenzene)	----	----	----	----	----	----	----	----	----	----	0.00E+00
Pentachlorophenol	----	----	----	----	----	----	----	----	----	----	0.00E+00
Phenol	----	7.74E-04	----	----	----	----	----	4.66E-03	----	----	5.43E-03
p-Phenylemediamine	----	----	----	----	----	----	----	----	----	----	0.00E+00
Phosgene	----	----	----	----	----	----	----	----	----	----	0.00E+00
Phosphine	----	----	----	----	----	----	----	----	----	----	0.00E+00
Phosphorus	----	----	----	----	----	----	----	----	----	----	0.00E+00
Phthalic anhydride	----	----	----	----	----	----	----	----	----	----	0.00E+00
Polychlorinated biphenyls (Aroclors)	----	----	----	----	----	----	2.53E-06	----	----	----	2.53E-06
Polycyclic Organic Matter (POM)	----	9.22E-04	2.30E-02	5.53E-04	2.12E-03	4.07E-02	----	----	----	5.95E-07	6.72E-02
Acenaphthene	----	----	----	----	----	----	----	----	----	----	
Acenaphthylene	----	----	----	----	----	----	----	----	----	----	
Anthracene	----	----	----	----	----	----	----	----	----	----	
Benzo(a)anthracene	----	----	----	----	----	----	----	----	----	----	
Benzo(a)pyrene	----	----	----	----	----	----	----	----	----	----	
Benzo(b)fluoranthene	----	----	----	----	----	----	----	----	----	----	
Benzo(g,h,i)perylene	----	----	----	----	----	----	----	----	----	----	
Benzo(k)fluoranthene	----	----	----	----	----	----	----	----	----	----	
Chrysene	----	----	----	----	----	----	----	----	----	----	
Dibenz(a,h)anthracene	----	----	----	----	----	----	----	----	----	----	
Acenaphthene	----	----	----	----	----	----	----	----	----	----	
Fluoranthene	----	----	----	----	----	----	----	----	----	----	
Fluorene	----	----	----	----	----	----	----	----	----	----	
Indeno(1,2,3-cd)pyrene	----	----	----	----	----	----	----	----	----	----	
7,12-Dimethylbenz(a)anthracene	----	----	----	----	----	----	----	----	----	----	
Naphthalene	----	----	----	----	----	----	----	----	----	----	
Naphtalene	----	----	----	----	----	----	----	----	----	----	
Phenathrene	----	----	----	----	----	----	----	----	----	----	
Pyrene	----	----	----	----	----	----	----	----	----	----	
1,3-Propane sultone	----	----	----	----	----	----	----	----	----	----	0.00E+00
beta-Propiolactone	----	----	----	----	----	----	----	----	----	----	0.00E+00
Propionaldehyde	----	1.84E-02	----	----	----	----	----	----	----	----	1.84E-02
Propoxur (Baygon)	----	----	----	----	----	----	----	----	----	----	0.00E+00
Propylene dichloride (1,2-Dichloropropane)	----	----	----	----	----	----	----	----	----	----	0.00E+00
Propylene oxide	----	----	----	----	----	----	----	----	----	----	0.00E+00
1,2-Propylenimine (2-Methyl aziridine)	----	----	----	----	----	----	----	----	----	----	0.00E+00
Quinoline	----	----	----	----	----	----	----	----	----	----	0.00E+00
Quinone	----	----	----	----	----	----	----	----	----	----	0.00E+00
Styrene	----	1.21E-03	----	----	----	----	----	----	----	----	1.21E-03
Styrene oxide	----	----	----	----	----	----	----	----	----	----	0.00E+00
Chlorinated dibenzo-p-dioxins (Total)	----	6.77E-10	----	----	----	----	1.16E-06	----	----	----	1.16E-06
1,1,2,2-Tetrachloroethane	----	----	----	----	----	----	----	----	----	----	0.00E+00
Tetrachloroethylene (Perchloroethylene)	----	2.08E-03	----	----	----	----	----	----	----	----	2.08E-03
Titanium tetrachloride	----	----	----	----	----	----	----	----	----	----	0.00E+00
Toluene	----	1.16E-02	4.31E-02	2.69E-03	5.18E-03	2.70E-02	----	1.69E-01	----	----	2.58E-01
2,4-Toluene diamine	----	----	----	----	----	----	----	----	----	----	0.00E+00
2,4-Tolluene diisocyanate	----	----	----	----	----	----	----	----	----	----	0.00E+00
o-Toluidine	----	----	----	----	----	----	----	----	----	----	0.00E+00
Toxaphene (chlorinated camphene)	----	----	----	----	----	----	----	----	----	----	0.00E+00
1,2,4-Trichlorobenzene	----	----	----	----	----	----	----	----	----	----	0.00E+00
1,1,2-Trichloroethane	----	9.68E-04	1.64E-03	----	----	3.93E-04	----	----	----	----	3.00E-03
Trichloroethylene	----	----	----	----	----	----	----	----	----	----	0.00E+00
2,4,5-Trichlorophenol	----	----	----	----	----	----	----	----	----	----	0.00E+00
2,4,6-Trichlorophenol	----	----	----	----	----	----	----	----	----	----	0.00E+00
Triethylamine	----	----	----	----	----	----	----	----	----	----	0.00E+00
Trifluralin	----	----	----	----	----	----	----	----	----	----	0.00E+00
2,2,4-Trimethylpentane	----	----	----	----	----	----	----	----	----	----	0.00E+00
Vinyl acetate	----	3.68E-04	----	----	----	----	----	----	----	----	3.68E-04
Vinyl bromide	----	----	----	----	----	----	----	----	----	----	0.00E+00
Vinyl chloride	----	----	----	----	----	----	----	----	----	----	0.00E+00
Vinylidene chloride (1,1-Dichloroethylene)	----	----	----	----	----	----	----	----	----	----	0.00E+00
Xylenes (isomers and mixture)	----	1.79E-03	7.58E-04	----	3.61E-03	1.86E-02	----	4.09E-02	----	----	6.57E-02

Hazardous Air Pollutant	HAP Emissions by Emission Unit Category (tons per year)[1]										Total HAP Emissions
	Storage Tank[2]	Coal-Fired Boilers	Diesel Boilers & Heaters (Except EU 4)	Natural Gas Boiler EU 3	Diesel Engines <=600 hp	EU 4 and EU 8	Waste Incinerators	Laboratory Hoods	Propane-Fired Kilns[3]	Pellet Stove	
Antimony Compounds	----	8.71E-04	----	----	----	----	6.98E-04	----	----	----	1.57E-03
Arsenic Compounds (inorganic including arsine)	----	1.98E-02	3.81E-03	1.58E-04	----	9.13E-04	1.32E-05	----	----	----	2.47E-02
Beryllium Compounds	----	1.02E-03	2.86E-03	9.51E-06	----	6.85E-04	3.41E-07	----	----	----	4.57E-03
Cadmium Compounds	----	2.47E-03	2.86E-03	8.72E-04	----	6.85E-04	2.99E-04	----	----	5.04E-07	7.18E-03
Chromium Compounds	----	1.64E-02	2.86E-03	1.11E-03	----	6.85E-04	4.22E-05	----	----	1.10E-08	2.11E-02
Cobalt Compounds	----	4.84E-03	----	6.66E-05	----	2.40E-05	----	----	----	----	4.93E-03
Coke Oven Emissions	----	----	----	----	----	----	----	----	----	----	0.00E+00
Cynaide Compounds	----	1.21E-01	----	----	----	----	----	----	----	----	1.21E-01
Glycol ethers	----	----	----	----	----	----	----	----	----	----	0.00E+00
Lead Compounds	----	2.03E-02	8.58E-03	----	----	2.06E-03	3.97E-03	----	----	----	3.49E-02
Magnesium Compounds	----	5.32E-01	----	----	----	----	----	----	----	----	5.32E-01
Manganese Compounds	----	2.37E-02	5.72E-03	3.01E-04	----	1.37E-03	3.09E-05	----	----	2.41E-06	3.11E-02
Mercury Compounds	----	4.09E-03	2.86E-03	2.06E-04	----	6.85E-04	5.83E-03	----	----	----	1.37E-02
Fine mineral fibers	----	----	----	----	----	----	----	----	----	----	0.00E+00
Nickel Compounds	----	1.35E-02	2.86E-03	1.66E-03	----	6.85E-04	3.22E-05	----	----	2.41E-08	1.88E-02
Radionuclides (including radon)	----	----	----	----	----	----	----	----	----	----	0.00E+00
Selenium Compounds	----	6.29E-02	1.43E-02	1.90E-05	----	3.43E-03	----	----	----	----	8.06E-02
Total HAPs - Maximum Individual HAP	**0**	**6.725**	**0.244**	**1.426**	**0.015**	**0.514**	**1.826**	**0.457**	**0**	**2.4E-06**	**8.5**
Total HAPs - Unit Category/Source	**0**	**14.530**	**0.361**	**1.496**	**0.049**	**0.749**	**1.851**	**1.144**	**0**	**3.5E-06**	**20.2**

Notes:

[1] See individual emissions unit category emissions calculations for details on methodology and assumptions.

[2] HAP emissions from the storage tank are negligible.

[3] No listed HAP emission rates in AP-42

[4] HAP emissions for EU 4 and EU 8 are the worst-case potential emissions for each individual HAP based on the cumulative 40 tpy NO_X limit for these two emission units.

Table 2-10. Estimated Potential HAP Emissions - Coal-Fired Boilers
University of Alaska Fairbanks Campus

Source Category Emission Calculations			
		Maximum Total Fuel Input	96,761 Tons of Coal/yr[1]
CAS No.	Chemical Name	Emission Factor[2]	Estimated Emissions
79005	1,1,2-Trichloroethane	2.00E-05 lb/ton	9.68E-04 tpy
1746016	2,3,7,8-Tetrachlorodibenzo-p-dioxin	1.40E-11 lb/ton	6.77E-10 tpy
121142	2,4-Dinitrotoluene	2.80E-07 lb/ton	1.35E-05 tpy
532274	2-Chloroacetophenone	7.00E-06 lb/ton	3.39E-04 tpy
75-07-0	Acetaldehyde	5.70E-04 lb/ton	2.76E-02 tpy
98862	Acetophenone	1.50E-05 lb/ton	7.26E-04 tpy
107-02-8	Acrolein	2.90E-04 lb/ton	1.40E-02 tpy
N/A	Antimony Compounds	1.80E-05 lb/ton	8.71E-04 tpy
N/A	Arsenic Compounds	4.10E-04 lb/ton	1.98E-02 tpy
71-43-2	Benzene	1.30E-03 lb/ton	6.29E-02 tpy
100447	Benzyl chloride	7.00E-04 lb/ton	3.39E-02 tpy
N/A	Beryllium Compounds	2.10E-05 lb/ton	1.02E-03 tpy
92524	Biphenyl	1.70E-06 lb/ton	8.22E-05 tpy
117817	Bis(2-ethylhexyl)phthalate (DEHP)	7.30E-05 lb/ton	3.53E-03 tpy
75252	Bromoform	3.90E-05 lb/ton	1.89E-03 tpy
N/A	Cadmium Compounds	5.10E-05 lb/ton	2.47E-03 tpy
75150	Carbon disulfide	1.30E-04 lb/ton	6.29E-03 tpy
108907	Chlorobenzene	2.20E-05 lb/ton	1.06E-03 tpy
67663	Chloroform	5.90E-05 lb/ton	2.85E-03 tpy
N/A	Chromium Compounds	3.39E-04 lb/ton	1.64E-02 tpy
N/A	Cobalt Compounds	1.00E-04 lb/ton	4.84E-03 tpy
98828	Cumene	5.30E-06 lb/ton	2.56E-04 tpy
N/A	Cyanide Compounds	2.50E-03 lb/ton	1.21E-01 tpy
132649	Dibenzofurans	1.09E-09 lb/ton	5.27E-08 tpy
77781	Dimethyl sulfate	4.80E-05 lb/ton	2.32E-03 tpy
100-41-4	Ethyl benzene	9.40E-05 lb/ton	4.55E-03 tpy
75003	Ethyl chloride (Chloroethane)	4.20E-05 lb/ton	2.03E-03 tpy
1006934	Ethylene dibromide (Dibromoethane)	1.20E-06 lb/ton	5.81E-05 tpy
107062	Ethylene dichloride (1,2-Dichloroethane)	4.00E-05 lb/ton	1.94E-03 tpy
50-00-0	Formaldehyde	2.40E-04 lb/ton	1.16E-02 tpy
110543	Hexane	6.70E-05 lb/ton	3.24E-03 tpy
7647010	Hydrochloric acid[3]	0.138 lb/ton	6.68 tpy
7664393	Hydrogen fluoride (Hydrofluoric acid)[3]	0.139 lb/ton	6.72 tpy
78591	Isophorone	5.80E-04 lb/ton	2.81E-02 tpy
N/A	Lead Compounds	4.20E-04 lb/ton	2.03E-02 tpy
N/A	Magnesium Compounds	1.10E-02 lb/ton	5.32E-01 tpy
N/A	Manganese Compounds	4.90E-04 lb/ton	2.37E-02 tpy
N/A	Mercury Compounds[3]	8.459E-05 lb/ton	4.09E-03 tpy
74839	Methyl bromide(Bromomethane)	1.60E-04 lb/ton	7.74E-03 tpy
78933	Methyl ethyl ketone (2-Butanone)	N/A	
60344	Methyl hydrazine	1.70E-04 lb/ton	8.22E-03 tpy
80626	Methyl methacrylate	2.00E-05 lb/ton	9.68E-04 tpy
1634044	Methyl tert butyl ether	3.50E-05 lb/ton	1.69E-03 tpy
74873	Methylchloride (chloromethane)	5.30E-04 lb/ton	2.56E-02 tpy
75092	Methylene chloride (Dichloromethane)	2.90E-04 lb/ton	1.40E-02 tpy
N/A	Nickel Compounds	2.80E-04 lb/ton	1.35E-02 tpy
108952	Phenol	1.60E-05 lb/ton	7.74E-04 tpy

Source Category Emission Calculations			
		Maximum Total Fuel Input	**96,761 Tons of Coal/yr[1]**
CAS No.	**Chemical Name**	**Emission Factor[2]**	**Estimated Emissions**
N/A	Polycylic Organic Matter	1.91E-05 lb/ton	9.22E-04 tpy
83-32-9	Acenaphthene	5.10E-07 lb/ton	
203-96-8	Acenaphthylene	2.50E-07 lb/ton	
120-12-7	Anthracene	2.10E-07 lb/ton	
56-55-3	Benzo(a)anthracene	8.00E-08 lb/ton	
205-99-5	Benzo(b)fluoranthene	1.10E-07 lb/ton	
50-32-8	Benzo(a)pyrene	3.80E-08 lb/ton	
191-24-2	Benzo(g,h,i)perylene	2.70E-08 lb/ton	
218-01-9	Chrysene	1.00E-07 lb/ton	
206-44-0	Fluoranthene	7.10E-07 lb/ton	
86-73-7	Fluorene	9.10E-07 lb/ton	
193-39-5	Ideno(1,2,3-cd)pyrene	6.10E-08 lb/ton	
	5-methylchrysene	2.20E-08 lb/ton	
91-20-3	Naphthalene	1.30E-05 lb/ton	
85-01-8	Phenanathrene	2.70E-06 lb/ton	
129-00-0	Pyrene	3.30E-07 lb/ton	
123386	Propionaldehyde	3.80E-04 lb/ton	1.84E-02 tpy
N/A	Selenium Compounds	1.30E-03 lb/ton	6.29E-02 tpy
100425	Styrene	2.50E-05 lb/ton	1.21E-03 tpy
127184	Tetrachloroethylene (Perchloroethylene)	4.30E-05 lb/ton	2.08E-03 tpy
108-88-3	Toluene	2.40E-04 lb/ton	1.16E-02 tpy
108054	Vinyl acetate	7.60E-06 lb/ton	3.68E-04 tpy
1330-20-7	Xylenes (isomers and mixture)	3.70E-05 lb/ton	1.79E-03 tpy
		Total HAP Emissions	**14.530 tpy**

Notes:

[1] Total coal-fired boiler fuel consumption based on operation of the following:

(2) Erie City Coal-Fired Boiler		84.5	MMBtu/hr, each
Potential Fuel Use	EU IDs 1 & 2	48,380	Ton of Coal/yr @ 8760 hrs/yr, each
	Total Potential Fuel Use	96,761	Ton of Coal/yr

Annual fuel use converted to ton of coal/year based on a coal heat content of 15.3 MMBtu/ton.

[2] Reference: AP-42, Tables 1.1-12, 1.1-13, 1.1-14, 1.1-18

[3]Emission factors are from source test results from boilers of a similar design at Clear Air Force Station. The UAF and Clear AFS boilers both combust Usibelli coal.

Table 2-11. Estimated Potential HAP Emissions - Diesel-Fired External Combustion Units (Boilers and Heaters)
University of Alaska Fairbanks Campus

Source Category Emission Calculations			All Boilers Except EU 4	EU 4
		Maximum Total Fuel Use	**13,917 kgal/yr[1]**	**3,333 kgal/yr[3]**
		Maximum Total Heat Input	**1.9066 10^{12} Btu/yr[1]**	**0.4567 10^{12} Btu/yr[3]**
CAS No.	**Chemical Name**	**Emission Factor [2]**	**Estimated Emissions**	**Estimated Emissions**
79-00-5	1,1,2-Trichloroethane	2.36E-04 lb/kgal	1.642E-03 tpy	3.933E-04 tpy
N/A	Arsenic Compounds	4.0 lb/10^{12} Btu	3.813E-03 tpy	9.133E-04 tpy
71-43-2	Benzene	2.14E-04 lb/kgal	1.489E-03 tpy	3.567E-04 tpy
N/A	Beryllium Compounds	3 lb/10^{12} Btu	2.860E-03 tpy	6.850E-04 tpy
N/A	Cadmium Compounds	3 lb/10^{12} Btu	2.860E-03 tpy	6.850E-04 tpy
N/A	Chromium Compounds	3 lb/10^{12} Btu	2.860E-03 tpy	6.850E-04 tpy
100-41-4	Ethyl benzene	6.36E-05 lb/kgal	4.426E-04 tpy	1.060E-04 tpy
5-00-0	Formaldehyde	3.50E-02 lb/kgal	2.435E-01 tpy	5.833E-02 tpy
N/A	Lead Compounds	9 lb/10^{12} Btu	8.580E-03 tpy	2.055E-03 tpy
N/A	Manganese Compounds	6 lb/10^{12} Btu	5.720E-03 tpy	1.370E-03 tpy
N/A	Mercury Compounds	3 lb/10^{12} Btu	2.860E-03 tpy	6.850E-04 tpy
N/A	Nickel Compounds	3 lb/10^{12} Btu	2.860E-03 tpy	6.850E-04 tpy
N/A	Polycylic Organic Matter	3.30E-03 lb/kgal	2.296E-02 tpy	5.500E-03 tpy
N/A	Selenium Compounds	15 lb/10^{12} Btu	1.430E-02 tpy	3.425E-03 tpy
108-88-3	Toluene	6.20E-03 lb/kgal	4.314E-02 tpy	1.033E-02 tpy
1330-20-7	Xylenes (isomers and mixture)	1.09E-04 lb/kgal	7.585E-04 tpy	1.817E-04 tpy
		Total HAP Emissions	**0.361 tpy**	**0.086 tpy**

Notes:

[1] Total fuel consumption based on full-time or permit-limited operation of the following:

(1) Zurn Dual-Fired Boiler		1,320 gal/hr		
	Potential Fuel Use EU ID 3		11,567,036	gallons/yr @ 8760 hrs/yr
(2) Burnham/V9OGA AFES Boiler		7.86 gal/hr, each		
	Potential Fuel Use EU ID 10		68,886	gallons/yr @ 8760 hrs/yr
	Potential Fuel Use EU ID 11		68,886	gallons/yr @ 8760 hrs/yr
(2) Weil McLain/BL776-S-W Harper Boiler #1		4.67 gal/hr, each		
	Potential Fuel Use EU ID 12		40,923	gallons/yr @ 8760 hrs/yr
	Potential Fuel Use EU ID 13		40,923	gallons/yr @ 8760 hrs/yr
(2) Energy Kinetics System 2000 Copper Lane Boiler		0.99 gal/hr, each		
	Potential Fuel Use EU ID 14		8,696	gallons/yr @ 8760 hrs/yr
	Potential Fuel Use EU ID 15		8,696	gallons/yr @ 8760 hrs/yr
(1) Weil McLain/P-WGO-5 Copper Lane (Honor's House) Boiler		1.70 ga/hr		
	Potential Fuel Use EU ID 16		14,920	gallons/yr @ 8760 hrs/yr
(2) Weil McLain/BL1688w-GPr10 West Ridge Research Building Boile		35.99 gal/hr, each		
	Potential Fuel Use EU ID 17		315,232	gallons/yr @ 8760 hrs/yr
	Potential Fuel Use EU ID 18		315,232	gallons/yr @ 8760 hrs/yr
(3) Weil McLain/2094W BiRD RM 100U3 Boiler #1		44.77 gal/hr, each		
	Potential Fuel Use EU IDs 19-21		879,708	gallons/yr @ 19,650 hrs/yr
(1) Bryan/EB200-S-150-FDGO BiRD RM 100U3 Boiler #4		62.04 gal/hr		

	Potential Fuel Use	EU ID 22		543,504	gallons/yr @ 8760 hrs/yr
(1) Sunderman/L02OUF AFES Greenhouse Furnace			1.53 gal/hr		
	Potential Fuel Use	EU ID 30		13,385	gallons/yr @ 8760 hrs/yr
(1) Matzger Copper Lane Furnace			0.58 gal/hr		
	Potential Fuel Use	EU ID 31		5,115	gallons/yr @ 8760 hrs/yr
(1) Rheem/ROBC-084QPEB Skarland Cabin Furnace			1.02 gal/hr		
	Potential Fuel Use	EU ID 32		8,952	gallons/yr @ 8760 hrs/yr
(1) Unknown AFES Grain Dryer			17.71 gal/hr		
	Potential Fuel Use	EU ID 25		1,771	gallons/yr @ 100 hrs/yr
(1) Bock Harper Hot Water Heater			1.72 gal/hr		
	Potential Fuel Use	EU ID 33		15,090	gallons/yr @ 8760 hrs/yr
		Total Potential Fuel Use		**13,916,956**	**gal/yr**

Annual fuel use converted to MMBtu/yr based on a diesel fuel heat content of 137,000 Btu/gal.

[2] Reference: AP-42, Tables 1.3-8, 1.3-9, and 1.3-10.

[3] EU 4 total fuel consumption based on: 3,333,333 gallons/yr under 40 tpy NO_X limit

Table 2-12. Estimated Potential HAP Emissions - Natural Gas-Fired Boilers
University of Alaska Fairbanks Campus

Source Category Emission Calculations				All Boilers Except EU 4	EU 4
			Maximum Total Fuel Use	**1,584.7 MMscf/yr[1]**	**571.4 MMscf/yr[3]**
No.	**CAS No.**	**Chemical Name**	**Emission Factor[2]**	**Estimated Emissions**	**Estimated Emissions**
12	106467	1,4-Dichlorobenzene(p)	1.20E-03 lb/MMscf	9.51E-04 tpy	3.43E-04 tpy
46	N/A	Arsenic Compounds	2.00E-04 lb/MMscf	1.58E-04 tpy	5.71E-05 tpy
48	71432	Benzene	2.10E-03 lb/MMscf	1.66E-03 tpy	6.00E-04 tpy
52	N/A	Beryllium Compounds	1.20E-05 lb/MMscf	9.51E-06 tpy	3.43E-06 tpy
58	N/A	Cadmium Compounds	1.10E-03 lb/MMscf	8.72E-04 tpy	3.14E-04 tpy
75	N/A	Chromium Compounds	1.40E-03 lb/MMscf	1.11E-03 tpy	4.00E-04 tpy
76	N/A	Cobalt Compounds	8.40E-05 lb/MMscf	6.66E-05 tpy	2.40E-05 tpy
109	5000	Formaldehyde	7.52E-02 lb/MMscf	5.96E-02 tpy	2.15E-02 tpy
118	110543	Hexane	1.80E+00 lb/MMscf	1.43E+00 tpy	5.14E-01 tpy
127	N/A	Manganese Compounds	3.80E-04 lb/MMscf	3.01E-04 tpy	1.09E-04 tpy
128	N/A	Mercury Compounds	2.60E-04 lb/MMscf	2.06E-04 tpy	7.43E-05 tpy
146	N/A	Nickel Compounds	2.10E-03 lb/MMscf	1.66E-03 tpy	6.00E-04 tpy
162	N/A	Polycylic Organic Matter	6.98E-04 lb/MMscf	5.53E-04 tpy	1.99E-04 tpy
		2-Methylnaphthalene	2.4E-05 lb/MMscf		
		3-Methylchloranthrene	1.8E-06 lb/MMscf		
		7,12-Dimethylbenz(a)anthracene	1.6E-05 lb/MMscf		
		Acenaphthene	1.8E-06 lb/MMscf		
		Acenaphthylene	1.8E-06 lb/MMscf		
		Anthracene	2.4E-06 lb/MMscf		
		Benz(a)anthracene	1.8E-06 lb/MMscf		
		Benzo(a)pyrene	1.2E-06 lb/MMscf		
		Benzo(a)fluoranthene	1.8E-06 lb/MMscf		
		Benzo(g,h,i)perylene	1.2E-06 lb/MMscf		
		Benzo(k)fluroanthene	1.8E-06 lb/MMscf		
		Chrysene	1.8E-06 lb/MMscf		
		Dibenzo(a,h)anthracene	1.2E-06 lb/MMscf		
		Fluoranthene	3.0E-06 lb/MMscf		
		Fluorene	2.8E-06 lb/MMscf		
		Indeno(1,2,3-cd)pyrene	1.8E-06 lb/MMscf		
145	91203	Naphthalene	6.10E-04 lb/MMscf		
		Phenanathrene	1.7E-05 lb/MMscf		
		Pyrene	5.0E-06 lb/MMscf		
171	N/A	Selenium Compounds	2.4E-05 lb/MMscf	1.90E-05 tpy	6.86E-06 tpy
176	108883	Toluene	3.40E-03 lb/MMscf	2.69E-03 tpy	9.71E-04 tpy
			Total HAP Emissions	**1.50 tpy**	**0.54 tpy**

Notes:

[1] Total fuel use based on maximum full-time operation or permit-limited operation as noted below:

(1) Zurn Dual-Fired Boiler 180,900 scf/hr

Potential Fuel Use EU ID 3 1,585 MMscf/yr @ 8,760 hrs/yr

1,000 Btu/scf fuel gas heating value used.

[2] Reference: AP-42, Tables 1.4-3, 1.4-4.

[3] Total fuel use based on maximum full-time operation or permit-limited operation as noted below:

(1) Zurn Dual-Fired Boiler 571 MMscf/yr under 40 tpy NO_X limit

Table 2-13. Estimated Potential HAP Emissions - Diesel-Fired Engines Greater Than 600 Horsepower
University of Alaska Fairbanks Campus

Source Category Emission Calculations			
		Maximum Total Heat Input	**192,281 MMBtu/yr[1]**
CAS No.	**Chemical Name**	**Emission Factor[2]**	**Estimated Emissions**
75-07-0	Acetaldehyde	2.52E-05 lb/MMBtu	2.42E-03 tpy
107-02-8	Acrolein	7.88E-06 lb/MMBtu	7.58E-04 tpy
71-43-2	Benzene	7.76E-04 lb/MMBtu	7.46E-02 tpy
5-00-0	Formaldehyde	7.89E-05 lb/MMBtu	7.59E-03 tpy
108-88-3	Toluene	2.81E-04 lb/MMBtu	2.70E-02 tpy
1330-20-7	Xylenes (isomers and mixture)	1.93E-04 lb/MMBtu	1.86E-02 tpy
N/A	Polycylic Organic Matter	4.23E-04 lb/MMBtu	4.07E-02 tpy
	Polycyclic aromatic compounds(PAH)	2.12E-04 lb/MMBtu	
	Acenaphthene	4.68E-06 lb/MMBtu	
	Acenaphthylene	9.23E-06 lb/MMBtu	
	Anthracene	1.23E-06 lb/MMBtu	
	Benzo(a)anthracene	6.22E-07 lb/MMBtu	
	Benzo(b)fluoranthene	1.11E-06 lb/MMBtu	
	Benzo(k)fluoranthene	2.18E-07 lb/MMBtu	
	Benzo(a)pyrene	2.57E-07 lb/MMBtu	
	Benzo(g,h,l)perylene	5.56E-07 lb/MMBtu	
	Chrysene	1.53E-06 lb/MMBtu	
	Dibenz(a,h)anthracene	3.46E-07 lb/MMBtu	
	Fluoranthene	4.03E-06 lb/MMBtu	
	Fluorene	1.28E-05 lb/MMBtu	
	Ideno(1,2,3-cd)pyrene	4.14E-07 lb/MMBtu	
91-20-3	Naphthalene	1.30E-04 lb/MMBtu	
	Phenanthrene	4.08E-05 lb/MMBtu	
	Pyrene	3.71E-06 lb/MMBtu	
		Total HAP Emissions	**0.17 tpy**

Notes:

[1] Total heat consumption based on full-time or permit-limited operation of the following:

(1) Fairbanks Morse Colt-Pielstick PC2.6 Peaking/Backup Generator (DEG) Engine		1,403,509	gal/yr
Potential Fuel Use	EU ID 8	192,280.7	MMBtu/yr
Total Potential Fuel Use		192,281	MMBtu/yr

Engine heat rate is assumed to be 7,000 Btu/hp-hr.

Maximum annual fuel use calculated in Table 2-4 and converted to MMBtu/yr based on a diesel fuel heat content of 137,000 Btu/gal.

[2] Reference: AP-42, Table 3.4-3.

Table 2-14. Estimated Potential HAP Emissions - Diesel-Fired Engines Less Than 600 Horsepower
University of Alaska Fairbanks Campus

Source Category Emission Calculations			
		Maximum Total Heat Input	**25,341 MMBtu/yr[1]**
CAS No.	**Chemical Name**	**Emission Factor[2]**	**Estimated Emissions**
75-07-0	Acetaldehyde	7.67E-04 lb/MMBtu	9.72E-03 tpy
107-02-8	Acrolein	9.25E-05 lb/MMBtu	1.17E-03 tpy
71-43-2	Benzene	9.33E-04 lb/MMBtu	1.18E-02 tpy
106-99-0	1,3-Butadiene	3.91E-05 lb/MMBtu	4.95E-04 tpy
5-00-0	Formaldehyde	1.18E-03 lb/MMBtu	1.50E-02 tpy
108-88-3	Toluene	4.09E-04 lb/MMBtu	5.18E-03 tpy
1330-20-7	Xylenes (isomers and mixture)	2.85E-04 lb/MMBtu	3.61E-03 tpy
N/A	Polycylic Organic Matter	1.68E-04 lb/MMBtu	2.12E-03 tpy
	Polycyclic aromatic compounds(PAH)	1.68E-04 lb/MMBtu	
	Acenaphthene	1.42E-06 lb/MMBtu	
	Acenaphthylene	5.06E-06 lb/MMBtu	
	Anthracene	1.87E-06 lb/MMBtu	
	Benzo(a)anthracene	1.68E-06 lb/MMBtu	
	Benzo(b)fluoranthene	9.91E-08 lb/MMBtu	
	Benzo(k)fluoranthene	1.55E-07 lb/MMBtu	
	Benzo(a)pyrene	1.88E-07 lb/MMBtu	
	Chrysene	3.53E-07 lb/MMBtu	
	Dibenz(a,h)anthracene	5.83E-07 lb/MMBtu	
	Fluoranthene	7.61E-06 lb/MMBtu	
	Fluorene	2.92E-05 lb/MMBtu	
	Ideno(1,2,3-cd)pyrene	3.75E-07 lb/MMBtu	
91-20-3	Naphthalene	8.48E-05 lb/MMBtu	
	Phenanthrene	2.94E-05 lb/MMBtu	
	Pyrene	4.78E-06 lb/MMBtu	
		Total HAP Emissions	**0.049 tpy**

Notes:

[1] Total heat consumption based on full-time or permit-limited operation or EPA guidance of 500 hours per 12-month rolling period for emergency engines for the following:

~~(2) Arctic Health Research Bldg. Emergency Generator~~		~~0.0 gal/hr, each~~	
	~~Potential Fuel Use EU ID 6~~		~~0.0 MMBtu/yr @ 100 hrs/yr~~
	~~Potential Fuel Use EU ID 7~~		~~0.0 MMBtu/yr @ 100 hrs/yr~~
(1) Alaska Center for Energy and Power Generator Engine		16.1 gal/hr	
	Potential Fuel Use EU ID 23		9,662.0 MMBtu/yr @ 4,380 hrs/yr
(1) Cummins/4B3.9-G2 Old University Park Emergency Generator Engir		3.5 gal/hr	
	Potential Fuel Use EU ID 24		47.9 MMBtu/yr @ 100 hrs/yr
(1) Mitsubishi-Bosch Duckering Classroom Engine		3.1 gal/hr	
	Potential Fuel Use EU ID 26		41.8 MMBtu/yr @ 99 hrs/yr
(1) Alaska Center for Energy and Power Generator Engine		25.5 gal/hr	
	Potential Fuel Use EU ID 27		15,330.0 MMBtu/yr @ 4,380 hrs/yr
(1) Alaska Earthquake Information Center Engine		6.1 gal/hr	
	Potential Fuel Use EU ID 28		84.0 MMBtu/yr @ 100 hrs/yr
(1) Arctic Health Research Engine		12.8 gal/hr	
	Potential Fuel Use EU ID 29		175.4 MMBtu/yr @ 100 hrs/yr
	Total Potential Fuel Use		25,341.1 MMBtu/yr

Engine heat rate is assumed to be 7,000 Btu/hp-hr.

Annual fuel use converted to MMBtu/yr based on a diesel fuel heat content of 137,000 Btu/gal.

[2] Reference: AP-42, Table 3.3-2.

Table 2-15. Estimated Potential HAP Emissions - Incinerator
University of Alaska Fairbanks Campus

Source Category Emission Calculations			
	Maximum Total Waste Input		**109 Tons of Waste/yr[1]**
CAS No.	**Chemical Name**	**Emission Factor [2]**	**Estimated Emissions**
1746016	Chlorinated dibenzo-p-dioxins (Total)	2.14E-05 lb/ton	1.16E-06 tpy
N/A	Antimony Compounds	1.28E-02 lb/ton	6.98E-04 tpy
N/A	Arsenic Compounds	2.42E-04 lb/ton	1.32E-05 tpy
N/A	Beryllium Compounds	6.25E-06 lb/ton	3.41E-07 tpy
N/A	Cadmium Compounds	5.48E-03 lb/ton	2.99E-04 tpy
7782505	Chlorine	1.05E-01 lb/ton	5.72E-03 tpy
N/A	Chromium Chompounds	7.75E-04 lb/ton	4.22E-05 tpy
132649	Dibenzofurans	7.16E-05 lb/ton	3.90E-06 tpy
7647010	Hydrochloric acid	33.5 lb/ton	1.83 tpy
7664393	Hydrogen fluoride (Hydrofluoric acid)	1.49E-01 lb/ton	0.01 tpy
N/A	Lead Compounds	7.28E-02 lb/ton	3.97E-03 tpy
N/A	Manganese Compounds	5.67E-04 lb/ton	3.09E-05 tpy
N/A	Mercury Compounds	1.07E-01 lb/ton	5.83E-03 tpy
N/A	Nickel Compounds	5.90E-04 lb/ton	3.22E-05 tpy
1336363	Polychlorinated biphenyls(Aroclors)	4.65E-05 lb/ton	2.53E-06 tpy
		Total HAP Emissions	**1.85 tpy**

Notes:

[1] Total waste combustion based on operation of the following:

(2) Therm-Tec/G-30P-1H BiRD Incinerator		83.3 lb/hr	
Potential Waste Combustion	EU ID 9A		109 Ton of Waste/yr (proposed ORL)
Total Potential Fuel Use			109 Ton of Waste/yr

[2] Reference: AP-42, Tables 2.3-2 through 2.3-6 and 2.3-9 through 2.3-13. Pathological waste incinerator emission factors are not available. Medical waste incineration emission factors are expected to be representative of emissions from a pathological waste incinerator.

Table 2-16. Estimated Potential HAP Emissions - Pellet Stove
University of Alaska Fairbanks Campus

		Source Category Emission Calculations	
CAS No.	**Chemical Name**	**Emission Factor[2]**	**Estimated Emissions**
N/A	Cadmium Compounds	4.60E-05 lb/ton	5.04E-07 tpy
N/A	Chromium Compounds	1.00E-06 lb/ton	1.10E-08 tpy
N/A	Manganese Compounds	2.20E-04 lb/ton	2.41E-06 tpy
N/A	Nickel Compounds	2.20E-06 lb/ton	2.41E-08 tpy
N/A	Polycylic Organic Matter	2.38E-04 lb/ton	5.95E-07 tpy
		Total HAP Emissions	**3.5E-06 tpy**

Notes:

[1] Total fuel consumption based on 8,760 hours per year of operation at 5 lb/hr:

SRC Pellet Stove fuel consumption	5.0 lb/hr =	21.9 ton/yr

[2] Reference: AP-42, Tables 1.10-3 and 1.10-4.

Table 2-21. Maximum Heat Input Calculations for Existing Boilers
University of Alaska Fairbanks Campus

Parameter			Data Source or Calculation Method
Description			
Maximum fuel input per boiler	5.46	ton/hr	Measured during PM source test, November 2010
Maximum fuel input to system	10.92	ton/hr	Boilers are identical; maximum possible input assumed the same for both
Maximum fuel input to system	21,840	lb/hr	(Maximum fuel input, ton/hr) x (2,000 lb/ton)
Heat content of coal combusted, as received	7,737	Btu/lb	UCM Rail Sample analysis for 11/3/2010
Heat content of coal combusted, as received	15.47	MMBtu/ton	(Heat content, Btu/lb as received) / (2,000 lb/ton)
Heat input to system	169.0	MMBtu/hr	(Max fuel input, lb/hr) x (Heat content, Btu/lb as received) / 10^6 Btu/MMBtu
Heat input per boiler	84.5	MMBtu/hr	Two identical boilers in system

Attachment E
Permit Applicability Rationale

The following document was prepared by Cam Leonard, Perkins Coie LLP.

UAF has evaluated whether the proposed revision to condition #17 would trigger the need for a minor permit under 18 AAC 50.502(c)(3). Our conclusion is that allowing operations above the current 10% capacity factor would simply permit us to operate Boiler 4 for more hours than are allowed under the permit as currently written. Increasing the hours of operations does not constitute either "a physical change to or a change in the method of operations of an existing stationary source." Our supporting rationale for this conclusion follows.

ADEC's regulations do not define the terms "physical change" or "change in method of operation," and there are no reported decisions from state courts interpreting them. But the same terms appear in the federal air regulations, in the definition of a "major modification" that triggers PSD permitting. *See* 40 C.F.R. §51.166(b)(2)(i) and 40 C.F.R. §52.21(b)(2)(i). Both of those federal regulatory definitions specifically exclude "an increase in the hours of operation," unless the change would be prohibited by a PSD permit. *See* 40 C.F.R. §51.166(b)(2)(iii)(*f*) and 40 C.F.R. §52.21(b)(2)(iii)(*f*).

These provisions of the federal regulations have also been subject to judicial interpretation, in contexts that shed light on our proposed permit modification. A discussion of the two leading cases follows.

Federal Case-law

Two federal appellate courts have considered the question of whether increasing the hours of operation of a stationary source triggers PSD permitting. In the first case, *U.S. v. Cinergy Corp.*,[1] the owner of a coal-fired power plant physically modified the plant to allow it to operate more, while not increasing its hourly emissions rate. When EPA said that the change was a major modification triggering PSD permitting, the owner claimed that it came within the regulatory exclusion for "an increase in the hours of operation or in the production rate." *See* 40 C.F.R. § 52.21(b)(2)(iii)(a), (f).

In rejecting the owner's argument and affirming EPA, the *Cinergy* court distinguished between situations where an operator simply proposed to a run a plant closer to its maximum capacity, and those where a physical change would enable the plant to increase its operational capacity. *See* 458 F.3d at 708. Because Cinergy's case fell within the latter category, PSD permitting was triggered.

Less than a year later, the U.S. Supreme Court, relying on the same distinction, reached a similar conclusion in *Environmental Defense v. Duke Energy*.[2] As in the *Cinergy* case, the power plant operator made physical changes that allowed boilers to run longer each day. Again,

[1] 458 F.3d 705 (Seventh Cir. 2006).
[2] 549 U.S. 561 (2007).

the operator claimed that this was not a "major modification" triggering PSD. In affirming EPA's position that PSD permitting applied, the Supreme Court acknowledged that "a mere increase in the hours of operation, standing alone, is not a 'physical change or change in the method of operation.'"[3] But because Duke Energy, like Cinergy before it, had made physical changes to allow the increased operations, it triggered PSD permitting.

In our case, UAF is not proposing any physical change to Boiler 4 that would increase its operational capacity. We simply propose to operate it more, as currently configured. Under the federal regulations, and federal case-law, the increased hours of operation are not a "change in the method of operation." UAF submits that ADEC should construe and apply its minor source regulation so as to be consistent with federal law on PSD modifications. To do otherwise would lead to regulatory confusion, and possible litigation.

[3] 549 U.S. 579.

Attachment F
EU 4 Permit Applicability Analysis and Emissions Calculations

Table F-1. UAF Permit Revision - Minor Air Quality Permit Applicability

Pollutant	Potential Emissions			Minor Permit Applicability Threshold	Permit Required
	EU 4 Existing Potential Emissions	EU 4 Future Potential Emissions	Change		
NO_X	40.0 tpy	40.0 tpy	0.0 tpy	10 tpy	No
CO	6.7 tpy	24.0 tpy	17.3 tpy	N/A	No
PM_{10}	1.9 tpy	5.5 tpy	3.6 tpy	10 tpy	No
$PM_{2.5}$	1.2 tpy	3.6 tpy	2.3 tpy	10 tpy	No
VOC	0.4 tpy	1.6 tpy	1.1 tpy	N/A	No
SO_2	40.0 tpy	40.0 tpy	0.0 tpy	10 tpy	No

Notes:

1. Existing and future potential emissions reflect the 40 tpy NO_X limit for EU 4 and EU 8.
2. Existing and future potential emissions reflect the 40 tpy SO_2 limit for EU 4 and EU 8.

Table F-2. UAF Permit Revision - Prevention of Significant Deterioration Permit Applicability

Pollutant	EU 4 Current Actual Emissions	EU 4 Projected Actual Emissions	Change	PSD Permit Applicability Threshold	Permit Required
NO_X	10.5 tpy	40.0 tpy	29.5 tpy	40 tpy	No
CO	4.5 tpy	24.0 tpy	19.5 tpy	100 tpy	No
PM	1.0 tpy	5.5 tpy	4.5 tpy	25 tpy	No
PM_{10}	1.0 tpy	5.5 tpy	4.5 tpy	15 tpy	No
VOC	0.3 tpy	1.6 tpy	1.3 tpy	40 tpy	No
SO_2	13.6 tpy	0.4 tpy	-13.3 tpy	40 tpy	No

Notes:

1. PM potential emissions are assumed to equal to PM_{10} potential emissions.
2. Projected actual emissions are conservatively assumed to equal future potential emissions, except for SO_2 because UAF now uses ULSD.
3. Projected actual emissions reflect the 40 tpy NO_X limit for EU 4 and EU 8, and the use of ULSD in EU 4.

Table F-3. UAF Permit Revision - Non Attainment New Source Review Permit Applicability

Pollutant	EU 4 Current Actual Emissions	EU 4 Projected Actual Emissions	Change	NANSR Permit Applicability Threshold	Permit Required
$PM_{2.5}$	0.7 tpy	3.6 tpy	2.8 tpy	10 tpy	No
NO_X	10.5 tpy	40.0 tpy	29.5 tpy	40 tpy	No
SO_2	13.6 tpy	0.4 tpy	-13.3 tpy	40 tpy	No

Notes:

1. Projected actual emissions are conservatively assumed to equal future potential emissions, except for SO_2 because UAF now uses ULSD.
2. Projected actual emissions reflect the 40 tpy NO_X limit for EU 4 and EU 8, and the use of ULSD in EU 4.

Table F-4. UAF Boiler EU 4 - 10% Capacity Factor Potential Emission Calculations

Pollutant	EU 4 Boiler Rating	Fuel	Emission Factor	Emission Factor Reference	Maximum Operation	Potential Emission	Worse-Case Potential Emissions
NO_X	180.9 MMBtu/hr	Diesel	24 lb/1,000 gal	AP-42 Table 1.3-1	1,157 kgal/yr	40.0 tpy	40.0 tpy
	180.9 MMBtu/hr	NG	140 lb/MMscf	AP-42 Table 1.4-1 low NO_X	158 MMscf/yr	11.1 tpy	
CO	180.9 MMBtu/hr	Diesel	5 lb/1,000 gal	AP-42 Table 1.3-1	1,157 kgal/yr	2.9 tpy	6.7 tpy
	180.9 MMBtu/hr	NG	84 lb/MMscf	AP-42 Table 1.4-1	158 MMscf/yr	6.7 tpy	
PM_{10}	180.9 MMBtu/hr	Diesel	3.3 lb/1,000 gal	AP-42 Tables 1.3-1, 1.3-2	1,157 kgal/yr	1.9 tpy	1.9 tpy
	180.9 MMBtu/hr	NG	7.6 lb/MMscf	AP-42 Table 1.4-2	158 MMscf/yr	0.6 tpy	
$PM_{2.5}$	180.9 MMBtu/hr	Diesel	2.13 lb/1,000 gal	AP-42 Tables 1.3-2, 1.3-7	1,157 kgal/yr	1.2 tpy	1.2 tpy
	180.9 MMBtu/hr	NG	7.6 lb/MMscf	AP-42 Table 1.4-2	158 MMscf/yr	0.6 tpy	
VOC	180.9 MMBtu/hr	Diesel	0.34 lb/1,000 gal	Table 1.3-1, AP-42	1,157 kgal/yr	0.2 tpy	0.4 tpy
	180.9 MMBtu/hr	NG	5.5 lb/MMscf	AP-42 Table 1.4-2	158 MMscf/yr	0.4 tpy	
SO_2	180.9 MMBtu/hr	Diesel	71 lb/1,000 gal	AP-42 Table 1.3-1	1,157 kgal/yr	40.0 tpy	40.0 tpy
	180.9 MMBtu/hr	NG	0.6 lb/MMscf	AP-42 Table 1.4-2	158 MMscf/yr	0.05 tpy	

Notes:

1. Maximum annual operation calculated as follows:
   Diesel, kgal/yr = (180.9 MMBtu/hr) x (0.10) x (8,760 hr/yr) / (0.137 MMBtu/gal) / (1,000 gal/kgal)
   NG, MMscf/yr = (180.9 MMBtu/hr) x (0.10) x (8,760 hr/yr) / (1,000 MMBtu/MMscf)
2. GHG (CO_2e) emissions = CO_2 emissions + (25 * CH_4 emissions) + (298 * N_2O emissions).
3. EU 4 and EU 8 have a cumulative NO_X emission limit of 40 tpy and a cumulative SO_2 emission limit of 40 tpy.
4. For each fuel, the PTE is calculated using the 10 percent capacity factor limit. The worse-case PTE is the greater of the two values.
5. Conversions and Constants:

Diesel Heating Value	0.137	MMBtu/gal
Maximum Diesel Sulfur Content	0.5	wt. pct.
Natural Gas Heat Content	1,000	Btu/scf
Weight	2,000	lb/ton
Weight	907.2	kg/ton

Table F-5. UAF Boiler EU 4 - Current Actual Emission Calculations

Pollutant	EU 4 Boiler Rating	Fuel	Emission Factor		Actual Operation	Actual Emission	Total Actual Emissions
				Reference			
NO_X	180.9 MMBtu/hr	Diesel	24 lb/1,000 gal	AP-42 Table 1.3-1	383 kgal/yr	4.6 tpy	10.5 tpy
	180.9 MMBtu/hr	NG	140 lb/MMscf	AP-42 Table 1.4-1 low NO_X	84 MMscf/yr	5.9 tpy	
CO	180.9 MMBtu/hr	Diesel	5 lb/1,000 gal	AP-42 Table 1.3-1	383 kgal/yr	1.0 tpy	4.5 tpy
	180.9 MMBtu/hr	NG	84 lb/MMscf	AP-42 Table 1.4-1	84 MMscf/yr	3.5 tpy	
PM_{10}	180.9 MMBtu/hr	Diesel	3.3 lb/1,000 gal	AP-42 Tables 1.3-1, 1.3-2	383 kgal/yr	0.6 tpy	1.0 tpy
	180.9 MMBtu/hr	NG	7.6 lb/MMscf	AP-42 Table 1.4-2	84 MMscf/yr	0.3 tpy	
$PM_{2.5}$	180.9 MMBtu/hr	Diesel	2.13 lb/1,000 gal	AP-42 Tables 1.3-2, 1.3-7	383 kgal/yr	0.4 tpy	0.7 tpy
	180.9 MMBtu/hr	NG	7.6 lb/MMscf	AP-42 Table 1.4-2	84 MMscf/yr	0.3 tpy	
VOC	180.9 MMBtu/hr	Diesel	0.34 lb/1,000 gal	Table 1.3-1, AP-42	383 kgal/yr	0.1 tpy	0.3 tpy
	180.9 MMBtu/hr	NG	5.5 lb/MMscf	AP-42 Table 1.4-2	84 MMscf/yr	0.2 tpy	
SO_2	180.9 MMBtu/hr	Diesel	71 lb/1,000 gal	AP-42 Table 1.3-1	383 kgal/yr	13.6 tpy	13.6 tpy
	180.9 MMBtu/hr	NG	0.6 lb/MMscf	AP-42 Table 1.4-2	84 MMscf/yr	0.03 tpy	

Notes:

1. Actual annual operations calculated in Table 7.
2. GHG (CO_2e) emissions = CO_2 emissions + (25 * CH_4 emissions) + (298 * N_2O emissions).
4. For each fuel, the actual emissions are calculated for each pollutant. The total actual emission is the sum of those emissions.
5. Conversions and Constants:

Diesel Heating Value	0.137	MMBtu/gal
Maximum Diesel Sulfur Content	0.5	wt. pct.
Natural Gas Heat Content	1,000	Btu/scf
Weight	2,000	lb/ton
Weight	907.2	kg/ton

Table F-6. UAF Boiler EU 4 - No Capacity Factor Potential Emission Calculations

Pollutant	EU 4 Boiler Rating	Fuel	Emission Factor	Emission Factor Reference	Maximum Operation	Potential Emission	Worse-Case Potential Emissions
NO_X	180.9 MMBtu/hr	Diesel	24 lb/1,000 gal	AP-42 Table 1.3-1	3,333 kgal/yr	40.0 tpy	40.0 tpy
	180.9 MMBtu/hr	NG	140 lb/MMscf	AP-42 Table 1.4-1 low NO_X	571 MMscf/yr	40.0 tpy	
CO	180.9 MMBtu/hr	Diesel	5 lb/1,000 gal	AP-42 Table 1.3-1	3,333 kgal/yr	8.3 tpy	24.0 tpy
	180.9 MMBtu/hr	NG	84 lb/MMscf	AP-42 Table 1.4-1	571 MMscf/yr	24.0 tpy	
PM_{10}	180.9 MMBtu/hr	Diesel	3.3 lb/1,000 gal	AP-42 Tables 1.3-1, 1.3-2	3,333 kgal/yr	5.5 tpy	5.5 tpy
	180.9 MMBtu/hr	NG	7.6 lb/MMscf	AP-42 Table 1.4-2	571 MMscf/yr	2.2 tpy	
$PM_{2.5}$	180.9 MMBtu/hr	Diesel	2.13 lb/1,000 gal	AP-42 Tables 1.3-2, 1.3-7	3,333 kgal/yr	3.6 tpy	3.6 tpy
	180.9 MMBtu/hr	NG	7.6 lb/MMscf	AP-42 Table 1.4-2	571 MMscf/yr	2.2 tpy	
VOC	180.9 MMBtu/hr	Diesel	0.34 lb/1,000 gal	Table 1.3-1, AP-42	3,333 kgal/yr	0.6 tpy	1.6 tpy
	180.9 MMBtu/hr	NG	5.5 lb/MMscf	AP-42 Table 1.4-2	571 MMscf/yr	1.6 tpy	
SO_2	180.9 MMBtu/hr	Diesel	71 lb/1,000 gal	AP-42 Table 1.3-1	3,333 kgal/yr	40.0 tpy	40.0 tpy
	180.9 MMBtu/hr	NG	0.6 lb/MMscf	AP-42 Table 1.4-2	571 MMscf/yr	0.17 tpy	

Notes:

1. Maximum annual operation calculated as follows:

   Diesel, kgal/yr = (40 ton NO_X/yr) x (2,000 lb/ton) / (24 lb NO_X/1,000 gal)

   NG, MMscf/yr = (40 ton NO_X/yr) x (2,000 lb/ton) / (140 lb NO_X/MMscf)

2. GHG (CO_2e) emissions = CO_2 emissions + (25 * CH_4 emissions) + (298 * N_2O emissions).
3. EU 4 and EU 8 have cumulative NO_X and SO_2 emission limits of 40 tpy for each pollutant.
4. For each fuel, the PTE is calculated based on the 40 tpy NO_X limit. The worse-case PTE is the greater of the two values.
5. UAF now only uses ULSD in EU 4. Projected actual emissions for EU 4, based on 0.0015 wt. pct. S in fuel, equal: 0.4 tpy.
6. Conversions and Constants:

Diesel Heating Value	0.137	MMBtu/gal
Maximum Diesel Sulfur Content	0.5	wt. pct.
Natural Gas Heat Content	1,000	Btu/scf
Weight	2,000	lb/ton
Weight	907.2	kg/ton

Table F-7. UAF Boiler EU 4 Actual Operations

ID	Emission Unit Description	Fuel Consumption, CY 2012	Fuel Consumption, CY 2011	Average Fuel Consumption
4	Power Plant Boiler - Diesel Fired	441.0 kgal/yr	324.6 kgal/yr	382.8 kgal/yr
4	Power Plant Boiler - Gas Fired	104.9 MMscf	63.9 MMscf	84.4 MMscf