ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION
Air Permits Program

BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION
for
University of Alaska Fairbanks
Fairbanks Campus Power Plant

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Abbreviations/Acronyms

AAC	Alaska Administrative Code
AAAQS	Alaska Ambient Air Quality Standards
Department	Alaska Department of Environmental Conservation
BACT	Best Available Control Technology
CFB	Circulating Fluidized Bed
CFR.	Code of Federal Regulations
Cyclones	Mechanical Separators
DFP	Diesel Particulate Filter
DLN	Dry Low NOx
DOC	Diesel Oxidation Catalyst
EPA	Environmental Protection Agency
ESP	Electrostatic Precipitator
EU	Emission Unit
FITR	Fuel Injection Timing Retard
GCPs	Good Combustion Practices
HAP	Hazardous Air Pollutant
ITR	Ignition Timing Retard
LEA	Low Excess Air
LNB	Low NOx Burners
MR&Rs	Monitoring, Recording, and Reporting
NESHAPS	National Emission Standards for Hazardous Air Pollutants
NSCR	Non-Selective Catalytic Reduction
NSPS	New Source Performance Standards
ORL	Owner Requested Limit
PSD	Prevention of Significant Deterioration
PTE	Potential to Emit
RICE, ICE	Reciprocating Internal Combustion Engine, Internal Combustion Engine
SCR	Selective Catalytic Reduction
SIP	Alaska State Implementation Plan
SNCR	Selective Non-Catalytic Reduction
ULSD	Ultra Low Sulfur Diesel

Units and Measures

gal/hr	gallons per hour
g/kWh	grams per kilowatt hour
g/hp-hr	grams per horsepower hour
hr/day	hours per day
hr/yr	hours per year
hp	horsepower
lb/hr	pounds per hour
lb/MMBtu	pounds per million British thermal units
lb/1000 gal	pounds per 1,000 gallons
kW	kilowatts
MMBtu/hr	million British thermal units per hour
MMscf/hr	million standard cubic feet per hour
ppmv	parts per million by volume
tpy	tons per year

Pollutants

CO	Carbon Monoxide
HAP	Hazardous Air Pollutant
NOx	Oxides of Nitrogen
SO_2	Sulfur Dioxide
PM-2.5	Particulate Matter with an aerodynamic diameter not exceeding 2.5 microns
PM-10	Particulate Matter with an aerodynamic diameter not exceeding 10 microns

1. INTRODUCTION

The University of Alaska Fairbanks (UAF) Campus facility has two coal-fired boilers, installed in 1962, and two oil-fired boilers (converted to dual fuel-fired by Minor Permit No. AQ0316MSS02), installed in 1970 and 1987. The power plant also has a 13,266 hp backup diesel generator installed in 1998. The UAF Campus also includes 13 diesel-fired boilers installed between 1985 and 2005, three emergency diesel engines installed between 1998 and 2013, one classroom engine installed in 1987, and one permitted diesel engine not yet installed. Additional permitted EUs not yet installed at the UAF Campus include limestone, sand, and ash handling systems, a circulating fluidized bed dual fuel-fired boiler, and a coal handling system.

In a letter dated April 24, 2015, the Alaska Department of Environmental Conservation (Department) requested the stationary sources expected to be major stationary sources in the particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers (PM-2.5) serious nonattainment area perform a voluntary Best Available Control Technology (BACT) review in support of the state agency's required SIP submittal once the nonattainment area is re-classified as a Serious PM-2.5 nonattainment area. The designation of the area as "Serious" with regard to nonattainment of the 2006 24-hour PM-2.5 ambient air quality standards was published in Federal Register Vol. 82, No. 89, May 10, 2017, pages 21703-21706, with an effective date of June 9, 2017.[1]

This report addresses the significant EUs listed in permit AQ0316TVP02, Revision 1 and permit AQ0316MSS06, Revision 1. This report provides the Department's review of the BACT analysis for PM-2.5 and BACT analyses provided for oxides of nitrogen (NOx) and sulfur dioxide (SO_2) emissions, which are precursor pollutants that can form PM-2.5 in the atmosphere post combustion.

The sections review UAF's BACT analysis for technical accuracy and adherence to accepted engineering cost estimation practices.

2. BACT EVALUATION

A BACT analysis is an evaluation of all available control options for equipment emitting the triggered pollutants and a process for selecting the best option based on feasibility, economics, energy, and other impacts. 40 CFR 52.21(b)(12) defines BACT as a site-specific determination on a case-by-case basis. The Department's goal is to identify BACT for the permanent emission units (EUs) at the UAF Campus Facility that emit NOx, PM-2.5, and SO_2, establish emission limits which represent BACT, and assess the level of monitoring, recordkeeping, and reporting (MR&Rs) necessary to ensure UAF applies BACT for the EUs. The Department based the BACT review on the five-step top-down approach set forth in Federal Register Volume 61, Number 142, July 23, 1996 (Environmental Protection Agency). Table A presents the EUs subject to BACT review.

[1] [1] Federal Register, Vol. 82, No. 89, Wednesday May 10, 2017 (https://dec.alaska.gov/air/anpms/comm/docs/2017-09391-CFR.pdf)

Table A: Emission Units Subject to BACT Review

EU ID[1]	Description of EU	Rating / Size		Fuel Type	Installation or Construction Date
3	Dual-Fired Boiler	180.9	MMBtu/hr	Dual Fuel	1970
4	Dual-Fired Boiler	180.9	MMBtu/hr	Dual Fuel	1987
8	Peaking/Backup Diesel Generator	13,266	hp	Diesel	1999
9A	Medical/Pathological Waste Incinerator	533	lb/hr	Medical / Infectious Waste	2006
19	Diesel Boiler	6.13	MMBtu/hr	Diesel	2004
20	Diesel Boiler	6.13	MMBtu/hr	Diesel	2004
21	Diesel Boiler	6.13	MMBtu/hr	Diesel	2004
23	Diesel Generator Engine	235	kW	Diesel	2003
24	Diesel Generator Engine	51	kW	Diesel	2001
26	Diesel Generator Engine	45	kW	Diesel	1987
27	Diesel Generator Engine	500	hp	Diesel	TBD
28	Diesel Generator Engine	120	hp	Diesel	1998
29	Diesel Generator Engine	314	hp	Diesel	2013
105	Limestone Handling System	1,200	acfm	N/A	TBD
107	Sand Handling System	1,600	acfm	N/A	TBD
109	Ash Handling System	1,000	acfm	N/A	TBD
110	Ash Handling System Vacuum	2,000	acfm	N/A	TBD
111	Ash Loadout to Truck	N/A		N/A	TBD
113	Dual Fuel-Fired Circulating Fluidized Bed (CFB) Boiler	295.6	MMBtu/hr	Coal/Woody Biomass	TBD
114	Dry Sorbent Handling Vent Filter Exhaust	5	acfm	N/A	TBD
128	Coal Silo No. 1 with Bin Vent	1,650	acfm	N/A	TBD
129	Coal Silo No. 2 with Bin Vent	1,650	acfm	N/A	TBD
130	Coal Silo No. 3 with Bin Vent	1,650	acfm	N/A	TBD

Table Notes:
[1]EUs 105, 107, 109-111, 113, 114, and 128-130 were authorized for construction with the issuance of Minor Permit AQ0316MSS06, Revision 2, but have not yet been installed.

UAF did not include BACT analyses for EUs 1 and 2 as it is required that these EUs be decommissioned with the startup of EU 113 under Minor Permit AQ0316MSS06, Revision 2. UAF did not include BACT analyses for EUs 10-16, 24-26, 28, and 29 because the emissions controls for these units are economically infeasible for the small potential emissions that could be controlled. Small diesel-fired boilers 17, 18, and 23, and small diesel-fired engine were also not included in the BACT analysis as these are units similar to those included in the BACT analysis. The Department did not require every EU to be included in the BACT analysis as long as a similar unit was included.

Five-Step BACT Determinations

The following sections explain the steps used to determine BACT for NOx, PM-2.5, and SO_2 for the applicable equipment.

Step 1 Identify All Potentially Available Control Technologies

The Department identifies all available control technologies for the EUs and the pollutant under consideration. This includes technologies used throughout the world or emission reductions through the application of available control techniques, changes in process design, and/or operational limitations. To assist in identifying available controls, the Department reviews available technologies listed on the Reasonably Available Control Technology (RACT), BACT, and Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC). The RBLC is an EPA database where permitting agencies nationwide post imposed BACT for PSD sources. In addition to the RBLC search, the Department used several search engines to look for emerging and tried technologies used to control NOx, PM-2.5, and SO_2 emissions from equipment similar to those listed in Table A.

Step 2 Eliminate Technically Infeasible Control Technologies:
The Department evaluates the technical feasibility of each control technology based on source specific factors in relation to each EU subject to BACT. Based on sound documentation and demonstration, the Department eliminates control technologies deemed technically infeasible due to physical, chemical, and engineering difficulties.

Step 3 Rank the Remaining Control Technologies by Control Effectiveness
The Department ranks the remaining control technologies in order of control effectiveness with the most effective at the top.

Step 4 Evaluate the Most Effective Controls and Document the Results as Necessary
The Department reviews the detailed information in the BACT analysis about the control efficiency, emission rate, emission reduction, cost, environmental, and energy impacts for each option to decide the final level of control. The analysis must present an objective evaluation of both the beneficial and adverse energy, environmental, and economic impacts. A proposal to use the most effective option does not need to provide the detailed information for the less effective options. If cost is not an issue, a cost analysis is not required. Cost effectiveness for a control option is defined as the total net annualized cost of control divided by the tons of pollutant removed per year. Annualized cost includes annualized equipment purchase, erection, electrical, piping, insulation, painting, site preparation, buildings, supervision, transportation, operation, maintenance, replacement parts, overhead, raw materials, utilities, engineering, start-up costs, financing costs, and other contingencies related to the control option. Sections 3, 4, and 5 present the Department's BACT Determinations for NOx, PM-2.5, and SO_2.

Step 5 Select BACT
The Department selects the most effective control option not eliminated in Step 4 as BACT for the pollutant and EU under review and lists the final BACT requirements determined for each EU in this step. A project may achieve emission reductions through the application of available technologies, changes in process design, and/or operational limitations. The Department reviewed UAF's BACT analysis and made BACT determinations for NOx, PM-2.5, and SO_2 for the UAF Campus Power Plant. These BACT determinations are based on the information submitted by UAF in their analysis, information from vendors, suppliers, sub-contractors, RBLC, and an exhaustive internet search.

3. BACT DETERMINATION FOR NOx

The NOx controls proposed in this section are not planned to be implemented. The optional precursor demonstration (as allowed under 40 C.F.R. 51.1006) for the precursor gas NOx for point sources illustrates that NOx controls are not needed. DEC is planning to submit with the Serious SIP a final precursor demonstration as justification not to require NOx controls. Please see the precursor demonstration for NOx posted at http://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-serious-sip-development. The PM2.5 NAAQS Final SIP Requirements Rule states if the state determines through a precursor demonstration that controls for a precursor gas are not needed for attaining the standard, then the controls identified as BACT/BACM or Most Stringent Measure for the precursor gas are not required to be implemented.[2] Final approval of the precursor demonstration is at the time of the Serious SIP approval.

The Department based its NOx assessment on BACT determinations found in the RBLC, internet research, and BACT analyses submitted to the Department by Golden Valley Electric Association (GVEA) for the North Pole Power Plant and Zehnder Facility, Aurora Energy, LLC (Aurora) for the Chena Power Plant, U.S. Army Corps of Engineers (US Army) for Fort Wainwright, and the University of Alaska Fairbanks (UAF) for the Combined Heat and Power Plant.

3.1 NOx BACT for the Large Dual Fuel-Fired Boiler (EU 113)

Possible NOx emission control technologies for the large dual fuel-fired boiler were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 11.110, Coal Combustion in Industrial Size Boilers and Furnaces. The search results for coal-fired boilers are summarized in Table 3-1.

Table 3-1. RBLC Summary of NOx Control for Industrial Coal-Fired Boilers

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Selective Catalytic Reduction	9	0.05 – 0.08
Selective Non-Catalytic Reduction	18	0.07 – 0.36
Low NOx Burners	18	0.07 – 0.3
Overfire Air	8	0.07 – 0.3
Good Combustion Practices	2	0.1 – 0.6

RBLC Review

A review of similar units in the RBLC indicates selective catalytic reduction, selective non-catalytic reduction, low NOx burners, and good combustion practices are the principle NOx control technologies installed on large dual fuel-fired boilers. The lowest NOx emission rate in the RBLC is 0.05 lb/MMBtu.

[2] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf

Step 1 - Identification of NOx Control Technology for the Large Dual Fuel-Fired Boiler
From research, the Department identified the following technologies as available for control of NOx emissions from the large dual fuel-fired boiler:

(a) Selective Catalytic Reduction (SCR)[3]
SCR is a post-combustion gas treatment technique for reducing nitric oxide (NO) and nitrogen dioxide (NO_2) in the turbine exhaust stream to molecular nitrogen (N_2), water, and oxygen (O_2). In the SCR process, aqueous or anhydrous ammonia (NH_3) is injected into the flue gas upstream of a catalyst bed. The catalyst lowers the activation energy of the NOx decomposition reaction. NOx and NH_3 combine at the catalyst surface forming an ammonium salt intermediate, which subsequently decomposes to produce elemental N_2 and water. Depending on the overall NH_3-to-NOx ratio, removal efficiencies are generally 70 to 90 percent. Challenges associated with using SCR on coal fired boilers include a narrow window of acceptable inlet and exhaust temperatures (500°F to 800°F), emission of NH_3 into the atmosphere (NH_3 slip) caused by non-stoichiometric reduction reaction, and disposal of depleted catalysts. The Department considers SCR a technically feasible control technology for the large dual fuel-fired boiler.

(b) Selective Non-Catalytic Reduction (SNCR)
SNCR involves the non-catalytic decomposition of NOx in the flue gas to N_2 and water using reducing agents such as urea or NH_3. The process utilizes a gas phase homogeneous reaction between NOx and the reducing agent within a specific temperature window. The reducing agent must be injected into the flue gas at a location in the unit that provides the optimum reaction temperature and residence time. The NH_3 process (trade name-Thermal DeNOx) requires a reaction temperature window of 1,600°F to 2,200°F. In the urea process (trade name–NO_xOUT), the optimum temperature ranges between 1,600°F and 2,100°F. Because the temperature of CFB boiler exhaust gas normally ranges from 1,550°F to 1,650°F, achieving the required reaction temperature is the main difficulty for application of SNCR to coal-fired boilers. Expected NOx removal efficiencies are typically between 40 to 62 percent, according to the RBLC, or between 30 and 50 percent reduction, according to the EPA fact sheet (EPA-452/F-03-031). Additionally, UAF received a statement from the manufacturer Babcock & Wilcox that SNCR would have a NOx removal efficiency of 10 to 20 percent with an ammonia lip of less than 20 ppm. The Department considers SNCR a technically feasible control technology for the large dual fuel-fired boiler.

(c) Non-Selective Catalytic Reduction (NSCR)
NSCR simultaneously reduces NOx and oxidizes CO and hydrocarbons in the exhaust gas to N_2, carbon dioxide (CO_2), and water. The catalyst, usually a noble metal, causes the reducing gases in the exhaust stream (hydrogen, methane, and CO) to reduce both NO and NO_2 to N_2 at a temperature between 800°F and 1,200°F, below the expected temperature of the CFB boiler flue gas. NSCR requires a low excess O_2 concentration in the exhaust gas stream to be effective because the O_2 must be depleted before the reduction chemistry can proceed. NSCR is only effective with rich-burn gas-fired units that operate at all times with an air/fuel ratio controller at or close to stoichiometric conditions. Coal-fired boilers

[3] https://www3.epa.gov/ttncatc1/dir1/fscr.pdf

operate under conditions far more fuel-lean than required to support NSCR. The Department's research did not identify NSCR as a control technology used to control NOx emissions from large coal fired boilers installed at any facility after 2005. The Department does not consider NSCR a technically feasible control technology for the large dual fuel-fired boiler.

(d) Low NOx Burners (LNBs)
Using LNBs can reduce formation of NOx through careful control of the fuel-air mixture during combustion. Control techniques used in LNBs includes staged air, and staged fuel, as well as other methods that effectively lower the flame temperature. Experience suggests that significant reduction in NOx emissions can be realized using LNBs. The U.S. EPA reports that LNBs have achieved reduction up to 80%, but actual reduction depends on the type of fuel and varies considerably from one installation to another. Typical reductions range from 40% - 60% but under certain conditions, higher reductions are possible. The Department considers the use of LNBs a technically feasible control technology for the large dual fuel-fired boiler.

(e) Circulating Fluidized Bed (CFB)
In a fluidized bed combustor, fuel is introduced to a bed of either sorbent (limestone) or inert material (usually sand) that is fluidized by an upward flow of air. This upward air flow allows for better mixing of the gas and solids to create a better heat transfer and chemical reactions. Combustion takes place in the bed at a lower temperature than other boiler types which lowers the formation of thermally generated NOx. The Department considers the use of a CFB as a technically feasible control technology for the large dual fuel-fired boiler.

(f) Low Excess Air (LEA)
Boiler operation with low excess air is considered an integral part of good combustion practices because this process can maximize the boiler efficiency while controlling the formation of NOx. Boilers operated with five to seven percent excess air typically have peak NOx formation from both peak combustion temperatures and chemical reactions. At both lower and higher excess air concentrations the formation of NOx is reduced. At higher levels of excess air, an increase in the formation of CO occurs. CO can increase reduced. As a result, the preference is to reduce excess air such that both NOx and CO generation is minimized and the boiler efficiency is optimized. Only one RLBC entry identified low excess air technology as a NOx control alternative for a mass-feed stoker designed boiler. Boilers are regularly designed to operate with low excess air as described in the previous LNB discussion. Low excess air technology can be achieved through LNB with a staged combustion and will therefore not be a technology carried forward.

(g) Good Combustion Practices (GCPs)
GCPs typically include the following elements:

1. Sufficient residence time to complete combustion;
2. Providing and maintaining proper air/fuel ratio;
3. High temperatures and low oxygen levels in the primary combustion zone;

4. High enough overall excess oxygen levels to complete combustion and maximize thermal efficiency.

Combustion efficiency is dependent on the gas residence time, the combustion temperature, and the amount of mixing in the combustion zone. GCPs are accomplished primarily through combustion chamber design as it relates to residence time, combustion temperature, air-to-fuel mixing, and excess oxygen levels. The Department considers GCPs a technically feasible control technology for the dual fuel-fired boiler.

(h) Fuel Switching
This evaluation considers retrofit of existing coal-fired boilers. It is assumed that use of another type of coal would not reduce NOx emissions. Therefore, the Department does not consider the use of an alternate fuel to be a technically feasible control technology for the dual fuel-fired boiler.

(i) Steam / Water Injection
Steam/water injection into the combustion zone reduces the firing temperature in the combustion chamber and has been traditionally associated with reducing NOx emissions from gas combustion turbines but not coal-fired boilers. In addition, steam/water has several disadvantages, including increases in carbon monoxide and un-burned hydrocarbon emissions and increased fuel consumption. Further, the Department found that steam or water injection is not listed in the EPA RBLC for use in any coal-fired boilers and it would be less efficient at controlling NOx emissions than SCR. Therefore, the Department does not consider steam or water injection to be a technically feasible control technology for the existing dual fuel-fired boiler.

(j) Reburn
Reburn is a combustion hardware modification in which the NOx produced in the main combustion zone is reduced in a second combustion zone downstream. This technique involves withholding up to 40 percent (at full load) of the heat input to the main combustion zone and introducing that heat input above the top row of burners to create a reburn zone. Reburn fuel (natural gas, oil, or pulverized coal) is injected with either air or flue gas to create a fuel-rich zone that reduces the NOx created in the main combustion zone to nitrogen and water vapor. The fuel-rich combustion gases from the reburn zone are completely combusted by injecting overfire air above the reburn zone. Reburn may be applicable to many boiler types firing coal as the primary fuel, including tangential, wall-fired, and cyclone boilers. However, the application and effectiveness are site-specific because each boiler is originally designed to achieve specific steam conditions and capacity which may be altered due to reburn. Commercial experience is limited; however, this limited experience does indicate NOx reduction of 50 to 60 percent from uncontrolled levels may be achieved. Reburn combustion control would require significant changes to the design of the existing boilers. Therefore, the Department does not consider reburn to be a technically feasible control technology to retrofit the existing dual fuel-fired boiler.

Step 2 - Eliminate Technically Infeasible NOx Control Technologies for the Dual Fuel-Fired Boiler
As explained in Step 1 of Section 3.1, the Department does not consider non-selective catalytic reduction, low NOx burners, fuel switching, steam/water injection, or reburn as technically feasible technologies to control NO_x emissions from the dual fuel-fired boiler.

Step 3 - Rank the Remaining NOx Control Technologies for the Large Dual Fuel-Fired Boiler
The following control technologies have been identified and ranked for control of NOx from the large dual fuel-fired boiler:

(a) Selective Catalytic Reduction (70% - 90% Control)
(b) Selective Non-Catalytic Reduction (30%-50% Control)
(g) Good Combustion Practices (Less than 40% Control)
(d) Low NOx Burners/Staged Combustion (0% Control)
(e) Circulating Fluidized Bed (0% Control)

Control technologies already in practice at the stationary source or included in the design of the EU are considered 0% control for the purpose of the SIP BACT for existing stationary sources.

Step 4 - Evaluate the Most Effective Controls

UAF BACT Proposal

UAF provided an economic analysis for the installation of SCR or SNCR in conjunction with CFB and staged combustion. A summary of the analysis is shown below:

Table 3-2. UAF Economic Analysis for Technically Feasible NOx Controls

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR	51.8	207.2	$26,740,640	$5,889,642	$22,232
SNCR	207.2	51.8	$2,960,000	$527,764	$10,192
Capital Recovery Factor = 0.1424 (7% interest rate for a 10 year equipment life)					

UAF contends that the economic analysis indicates the level of NOx reduction does not justify the use of SCR or SNCR for the dual fuel-fired boiler based on the excessive cost per ton of NOx removed per year.

UAF proposed the following as BACT for the large dual fuel-fired boiler:

(a) NOx emissions from the operation of the dual fired boiler will be controlled with the use of CFB and staged combustion; and

(b) NOx emissions from the large dual fuel-fired boiler shall not exceed 0.2 lb/MMBtu.

Department Evaluation of BACT for NOx Emissions from the Dual Fuel-Fired Boiler
The Department revised the cost analysis provided by UAF for the installation of SCR and SNCR using EPA's May 2016 Air Pollution Control Cost Estimation Spreadsheet for Selective Catalytic

Reduction,[4] and Selective Non-Catalytic Reduction,[5] using the unrestricted potential to emit of EU 113, a baseline emission rate of 0.2 lb NOx/MMBtu,[6] a retrofit factor of 1.0 for a retrofit of average difficulty, a NOx removal efficiency of 90% and 50% for SCR and SNCR respectively, an interest rate of 5.5% (current bank prime interest rate), and a 20 year equipment life. A summary of the analysis is shown below:

Table 3-3. Department Economic Analysis for Technically Feasible NOx Controls

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR	259	233	$11,676,081	$1,444,246	$6,197
SNCR	259	129	$2,170,943	$291,628	$2,252
Capital Recovery Factor = 0.0837 (5.5% interest rate for a 20 year equipment life)					

The Department's economic analysis indicates the level of NOx reduction justifies the use of SCR or SNCR for the dual fuel-fired boiler located in the Serious PM-2.5 nonattainment area.

Step 5 - Selection of NOx BACT for the Large Dual Fuel-Fired Boiler

The Department's finding is that selective catalytic reduction and selective non-catalytic reduction are both economically and technically feasible control technologies for NOx. Since selective catalytic reduction has a higher control efficiency, it is selected as BACT to control NOx emissions from the dual fuel-fired boiler.

The Department's finding is that BACT for NOx emissions from the dual fuel-fired boiler is as follows:

(a) NOx emissions from EU 113 shall be controlled by operating and maintaining SCR in conjunction with the designed CFB and staged combustion at all times the unit is in operation;

(b) NOx emissions from EU 113 shall not exceed 0.02 lb/MMBtu averaged over a 3-hour period; and

(c) Maintain good combustion practices by following the manufacturer's operational procedures at all times of operation.

Table 3-4 lists the proposed BACT determination for this facility along with those for other coal-fired boilers in the Serious PM-2.5 nonattainment area.

[4] https://www3.epa.gov/ttn/ecas/docs/scr_cost_manual_spreadsheet_2016_vf.xlsm
[5] https://www3.epa.gov/ttn/ecas/docs/sncr_cost_manual_spreadsheet_2016_vf.xlsm
[6] Emission rate is NOx limit from 40 C.F.R. 60.44b(l)(1) [NSPS Subpart Db]

Table 3-4. Comparison of NOx BACT for Coal-Fired Boilers at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
UAF	Dual Fuel-Fired Boiler	295.6 MMBtu/hr	0.02 lb/MMBtu[7]	Selective Catalytic Reduction
Fort Wainwright	6 Coal-Fired Boilers	1,380 MMBtu/hr	0.06 lb/MMBtu[8]	Selective Catalytic Reduction
Chena	Four Coal-Fired Boilers	497 MMBtu/hr (combined)	0.05 lb/MMBtu[9]	Selective Catalytic Reduction

3.2 NOx BACT for the Mid-Sized Diesel-Fired Boilers (EUs 3 and 4)

Possible NOx emission control technologies for mid-sized diesel-fired boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 12.220, Industrial Size Distillate Fuel Oil Boilers (>100 MMBtu/hr and ≤ 250 MMBtu/hr). The search results for mid-sized diesel-fired boilers are summarized in Table 3-5.

Table 3-5. RBLC Summary of NOx Control for Mid-Sized Boilers Firing Diesel

Control Technology	Number of Determinations	Emission Limits (lb/1000 gal)
No Control Specified	2	4 – 13

Possible NOx emission control technologies for mid-sized diesel-fired boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 12.310, Industrial Size Gaseous Fuel Boilers (>100 MMBtu/hr and ≤ 250 MMBtu/hr). The search results for mid-sized diesel-fired boilers are summarized in Table 3-6.

Table 3-6. RBLC Summary of NOx Control for Mid-Sized Boilers Firing Natural Gas

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Selective Catalytic Reduction	7	0.01 – 0.014
Low NOx Burners	26	0.01 – 0.12
Limited Operation	1	0.098
Good Combustion Practices	6	0.0002 – 0.119
No Control Specified	7	0.04 – 0.14

RBLC Review

A review of similar units in the RBLC indicates selective catalytic reduction, low-NOx burners, limited operation, and good combustion practices are the principle NOx control technologies installed on mid-sized boilers. The lowest NOx emission rate listed in the RBLC is 0.0002 lb/MMBtu.

Step 1 - Identification of NOx Control Technology for the Mid-Sized Diesel-Fired Boilers

[7] Calculated using a 90% NOx control efficiency for SCR with uncontrolled emission rate from 40 C.F.R. 60.44b(l)(1) [NSPS Subpart Db].

[8] Calculated using a 90% NOx control efficiency for SCR with uncontrolled emission factor from AP-42 Table 1.1-3 for spreader stoker sub-bituminous coal (8.8 lb NOx/ton) and converted to lb/MMBtu using heat value for Usibelli Coal of 7,560 Btu/lb, http://www.usibelli.com/coal/data-sheet.

[9] Calculated using a 90% NOx control efficiency for SCR with uncontrolled emission rate from most recent NOx source test, which occurred on Oct 27, 2018.

From research, the Department identified the following technologies as available for NOx control of mid-sized diesel-fired boilers:

(a) Selective Catalytic Reduction
The theory of SCR was discussed in detail in the NOx BACT for the dual fuel-fired boiler and will not be repeated here. The Department considers SCR a technically feasible control technology for the mid-sized diesel-fired boilers.

(b) Selective Non-Catalytic Reduction
The theory of SNCR was discussed in detail in the NOx BACT for the CFB dual fuel-fired boiler and will not be repeated here. The expected NOx control efficiency for the SNCR without LNB is 30 to 50 percent, and with LNB is 65 to 75 percent. The Department considers SNCR a technically feasible control technology for the mid-sized diesel-fired boilers.

(c) Low NOx Burners
The theory of LNBs was discussed in detail in the NOx BACT for the CFB dual fuel-fired boiler and will not be repeated here. EUs 3 and 4 currently have LNB controls in the place. If the LNB systems were to be replaced an estimated NOx control efficiency of 35 to 55 percent is expected. The use of LNBs is a technically feasible control technology for the mid-sized diesel-fired boilers.

(d) Natural Gas
Natural gas combustion has a lower NOx emission rate than diesel combustion. For this reason, combustion of natural gas rather than diesel is preferred. EU 4 is equipped to burn natural gas, but due to the lack of guarantee of natural gas always being available to them, UAF has retained the ability due to burn diesel in EU 4. EU 3 is not currently configured to burn natural gas. UAF has had pressure issues with operating EU 4 on natural gas and feels that operating both mid-sized diesel-fired boilers on natural gas would create an issue. The Department agrees that operating on natural gas is not a technically feasible control technology for the mid-sized diesel-fired boilers.

(e) Limited Operation
EU 4 currently has an owner requested limit through the Title I permitting program to limit NOx emissions to no more than 40 tons per 12 month rolling period. With the limit on operation in place the NOx emissions are reduced from EU 4. The Department considers limited operation a technically feasible control technology for the mid-sized diesel-fired boilers.

(f) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the CFB dual fuel-fired boiler and will not be repeated here. Proper management of the combustion process will result in a reduction of NOx emissions. The Department considers GCPs a technically feasible control technology for the mid-sized diesel-fired boilers.

Step 2 - Eliminate Technically Infeasible NOx Controls for the Mid-Sized Boilers
As explained in Step 1 of Section 3.2, the Department does not consider switching fuel to natural gas as technically feasible technologies to control NOx emissions from the mid-sized diesel-fired boilers.

For EU 4, SCR is not a technically feasible technology due to the lack of space surrounding the EU required for an SCR system.

EU 3 is used as a backup to the existing large boilers if one of them fails, and will be used as the backup to EU 113 if it fails. As the backup EU, it is not technically feasible to use an operational limit to control NOx emissions.

SNCR is not identified in the RBLC as a control technology used for diesel-fired boilers between 100 and 250 MMBtu/hr and is therefore not considered a feasible technology.

Step 3 - Rank the Remaining NOx Control Technologies for the Mid-Sized Diesel-Fired Boilers
The following control technologies have been identified and ranked by efficiency for the control of NOx emissions from EU 3.

(a) Selective Catalytic Reduction (80% - 90% Control)
(c) Low NOx Burners (35% - 55% Control)
(f) Good Combustion Practices (Less than 40% Control)

The following control technologies have been identified and ranked by efficiency for the control of NOx emissions from EU 4.

(c) Low NOx Burners (35% - 55% Control)
(f) Good Combustion Practices (Less than 40% Control)
(e) Limited Operation (0% Control)

Control technologies already in practice at the stationary source or included in the design of the EU are considered 0% control for the purpose of the SIP BACT for existing stationary sources.

Step 4 - Evaluate the Most Effective Controls

UAF BACT Proposal

UAF provided an economic analysis for the installation of LNB and SCR. A summary of the analysis is shown below:

Table 3-7. Economic Analysis for Technically Feasible NOx Controls

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR (EU 3)	20.8	118.0	$3,434,525	$992,901	$7,261
LNB (EU 3)	79.2	59.6	$1,255,695	$216,454	$3,634
LNB (EU 4)	12.7	1.2	$1,342,628	$231,439	$189,312
Capital Recovery Factor = 0.1424 (7% interest rate for a 10 year equipment life)					

UAF contends that the economic analysis indicates the level of NOx reductions does not justify the use of SCR or LNB for the mid-sized diesel fired boilers based on the excessive cost per ton of NOx removed.

UAF proposed the following as BACT for NOx emissions from EU 3:

(a) NOx emissions from the operation of EU 3 shall be controlled by good combustion practices; and

(b) NOx emissions from EU 3 shall not exceed 0.2 lb/MMBtu.

UAF proposes the following as BACT for NOx emissions from EU 4:

(a) NOx emissions from the operation of EU 4 shall be controlled by limited operation;

(b) Combined NOx emissions from EUs 4 and 8 shall not exceed 40 tons per 12 month rolling period;

(c) NOx emissions from the operation of EU 4 shall be controlled by good combustion practices; and

(c) NOx emissions from EU ID 4 shall not exceed 0.2 lb/MMBtu while firing diesel fuel and 140 lb/MMscf while firing natural gas.

Department Evaluation of BACT for NOx Emissions from the Mid-Sized Diesel-Fired Boilers

The Department revised the cost analyses provided by UAF for the installation of SCR and LNB on EU 3 using a NOx control efficiency of 90% and 55% respectively, an interest rate of 5.5% (current bank prime interest rate), and a 20 year equipment life. A summary of the analysis is shown below:

Table 3-8. Department Economic Analysis for Technically Feasible NOx Controls

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR	138.8	125	$3,434,525	$792,939	$6,348
LNB	138.8	76	$1,255,695	$142,747	$1,870
Capital Recovery Factor = 0.0837 (5.5% interest rate for a 20 year equipment life)					

The Department's economic analysis indicates the level of NOx reduction justifies the use of SCR or LNB as BACT for EU 3 located in the Serious PM-2.5 nonattainment area.

The Department reviewed UAF's proposal for EU 4 and finds that because the EU is already limited to 40 tpy of NOx emissions combined with EU 8, requiring the installation and operation of any add-on control technology will not further reduce annual NOx emissions.

Step 5 - Selection of NOx BACT for the Mid-Sized Diesel-Fired Boilers

The Department's finding is that selective catalytic reduction and low NOx burners are both economically and technically feasible control technologies for NOx. Since selective catalytic reduction has a higher control efficiency, it is selected as BACT to control NOx emissions from EU 3.

The Department's finding is that BACT for NOx emissions from EU 3 is as follows:

(a) NOx emissions from EU 3 shall be controlled by operating and maintaining selective catalytic reduction at all times the unit is in operation;

(b) NOx emissions from EU 3 shall not exceed 0.02 lb/MMBtu averaged over a 3-hour averaging period; and

(c) Maintain good combustion practices at all times of operation by following the manufacturer's operation and maintenance procedures.

The Department's finding is that BACT for NOx emissions from EU 4 is as follows:

(a) NOx emissions from EU 4 shall be controlled by limiting the combined NOx emissions of EU 4 and 8 to no more than 40 tons per 12 month rolling period;

(b) Maintain good combustion practices at all times of operation by following the manufacturer's operation and maintenance procedures and

(c) NOx emissions from EU 4 shall not exceed 0.2 lb/MMBtu while firing diesel fuel and 140 lb/MMscf while firing natural gas, both over a 3-hour averaging period.

Table 3-9 lists the proposed NOx BACT determination for the facility along with those for other mid-sized diesel-fired boilers in the Serious PM-2.5 nonattainment area.

Table 3-9. Comparison of NOx BACT for the Mid-Sized Diesel-Fired Boilers

<table>
<tr><th>Facility</th><th>EU ID</th><th>Process Description</th><th>Capacity</th><th>Fuel</th><th>Limitation</th><th>Control Method</th></tr>
<tr><td rowspan="3">UAF</td><td>3</td><td rowspan="3">Dual Fuel-Fired Boilers</td><td rowspan="3">100 – 250 MMBtu/hr</td><td>Diesel</td><td>0.02 lb/MMBtu</td><td>Selective Catalytic Reduction
Good Combustion Practices</td></tr>
<tr><td rowspan="2">4</td><td>Diesel</td><td>0.2 lb/MMBtu</td><td rowspan="2">Limited Operation
Good Combustion Practices</td></tr>
<tr><td>Natural Gas</td><td>140 lb/MMscf</td></tr>
</table>

3.3 NOx BACT for the Small Diesel-Fired Boilers (EUs 19-21)

Possible NOx emission control technologies for small diesel-fired boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 13.220, Commercial/Institutional Size Boilers (<100 MMBtu/hr). The search results for the small diesel-fired boilers are summarized in Table 3-10.

Table 3-10. RBLC Summary of NOx Control for Small Diesel-Fired Boilers

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Low NOx Burners	3	0.02 – 0.14
Good Combustion Practices	1	0.01

RBLC Review

A review of similar units in the RBLC low NOx burners, and good combustion practices are the principle NOx control technologies installed on small-diesel fired boilers. The lowest emission rate listed in the RBLC is 0.01 lb/MMBtu.

Step 1 - Identification of NOx Control Technology for the Small Diesel-Fired Boilers

From research, the Department identified the following technologies as available for control of NOx emissions from small diesel-fired boilers:

(a) Low NOx Burners
The theory of LNBs was discussed in detail in the NOx BACT for the large dual fuel-fired boiler and will not be repeated here. The Department considers LNB a technically feasible control technology for small diesel-fired boilers.

(b) Limited Operation
The three small diesel-fired boilers share an operating limit of 19,650 hours per 12 rolling month period. Limiting the operation of emission units reduces the potential to emit for those units. The Department considers limited operation a technically feasible control technology for the small diesel-fired boilers.

(c) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the large dual fuel-fired boiler and will not be repeated here. The Department considers GCPs a technically feasible control technology for the small diesel-fired boilers.

(d) Flue Gas Recirculation (FGR)
Flue gas recirculation involves extracting a portion of the flue gas from the economizer section or air heater outlet and readmitting it to the furnace through the furnace hopper, the burner windbox, or both. This method reduces the concentration of oxygen in the combustion zone and may reduce NOx by as much as 40 to 50 percent in some boilers. Chapter 1.3-7 from AP-42 indicates that FGR can require extensive modifications to the burner and windbox and can result in possible flame instability at high FGR rates. The Department does not consider FGR a technically feasible control technology for the small diesel-fired boilers.

Step 2 - Eliminate Technically Infeasible NOx Control Technologies for the Small Diesel-Fired Boilers
As explained in Step 1 of Section 3.2, the Department does not consider flue gas recirculation as technically feasible technology for the small diesel-fired boilers.

Step 3 - Rank the Remaining NOx Control Technologies for the Small Diesel-Fired Boilers
The following control technologies have been identified and ranked by efficiency for the control of NOx emissions from the small diesel-fired boilers:

(a)	Low NOx Burners	(35% - 55% Control)
(c)	Good Combustion Practices	(Less than 40% Control)
(b)	Limited Operation	(0% Control)

Control technologies already in practice at the stationary source or included in the design of the EU are considered 0% control for the purpose of the SIP BACT for existing stationary sources.

Step 4 - Evaluate the Most Effective Controls

UAF BACT Proposal

UAF proposes the following as BACT for NOx emissions from the small diesel-fired boilers:

(a) NOx emissions from the operation of the small diesel-fired boilers shall be controlled with limited operation;

(b) Limit the combined operation of EUs 19-21 to no more than 19,650 hours in any 12 month rolling period; and

(c) NOx emissions from the small diesel-fired boilers shall not exceed 1.24 g/MMBtu.

Department Evaluation of BACT for NOx Emissions from Small Diesel-Fired Boilers

The Department reviewed UAF's proposal and finds that the 3 small diesel-fired boilers have a combined potential to emit (PTE) of 8.8 tons per year (tpy) for NOx based on combined operation of 19,650 hours per year. At 8.8 tpy, the cost effectiveness in terms of dollars per ton for add-on pollution control for these units is economically infeasible. The Department finds that in addition to limiting the operation of the small diesel-fired boilers, good combustion practices is BACT for NOx.

Step 5 - Selection of NOx BACT for the Small Diesel-Fired Boilers

The Department's finding is that BACT for NOx emissions from the diesel-fired boilers is as follows:

(a) NOx emissions from EUs 19-21 shall not exceed 0.15 lb/MMBtu[10];

(b) Combined operating limit of no more than 19,650 hours per 12 month rolling period;

(c) Maintain good combustion practices by following the manufacturer's operational procedures at all times of operation; and

(d) Compliance with the hour limit will be monitored with an hour meter.

Table 3-11 lists the proposed BACT determination for this facility along with those for other diesel-fired boilers rated at less than 100 MMBtu/hr in the Serious PM-2.5 nonattainment area.

Table 3-11. Comparison of NOx BACT for the Small Diesel-Fired Boilers at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
UAF	3 Diesel-Fired Boilers	< 100 MMBtu/hr	0.15 lb/MMBtu	Limited Operation Good Combustion Practices
Fort Wainwright	27 Diesel-Fired Boilers	< 100 MMBtu/hr	0.15 lb/MMBtu	Limited Operation Good Combustion Practices
GVEA Zehnder	2 Diesel-Fired Boilers	< 100 MMBtu/hr	0.15 lb/MMBtu	Low NOx Burners

3.4 NOx BACT for the Large Diesel-Fired Engine (EU 8)

Possible NOx emission control technologies for large engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 17.100 to

[10] Emission rate from AP-42 Table 1.3-1 for boilers smaller than 100 MMBtu/hr (20 lb/1,000 gallons of diesel) and converted to lb/MMBtu assuming 0.137 MMBtu/gal diesel (AP-42).

17.190, Large Internal Combustion Engines (>500 hp). The search results for large diesel-fired engines are summarized in Table 3-12.

Table 3-12. RBLC Summary for NOx Controls for Large Diesel-Fired Engines

Control Technology	Number of Determinations	Emission Limits (g/hp-hr)
Selective Catalytic Reduction	3	0.5 - 0.7
Other Add-On Control	1	1.0
Federal Emission Standards	13	3.0 - 6.9
Good Combustion Practices	31	3.0 - 13.5
No Control Specified	60	2.8 - 14.1

RBLC Review
A review of similar units in the RBLC indicates selective catalytic reduction, good combustion practices, and compliance with the federal emission standards are the principle NOx control technologies installed on large diesel-fired engines. The lowest NOx emission rate listed in the RBLC is 0.5 g/hp-hr.

Step 1 - Identification of NOx Control Technology for the Large Diesel-Fired Engine
From research, the Department identified the following technologies as available for the control of NOx emissions from diesel-fired engines rated at 500 hp or greater:

(a) Selective Catalytic Reduction
The theory of SCR was discussed in detail in the NOx BACT for the dual fuel-fired boiler and will not be repeated here. EU 8 currently has an SCR system installed at this time, therefore, the Department considers SCR a technically feasible control technology for the large diesel-fired engine.

(b) Turbocharger and Aftercooler
Turbocharger technology involves the process of compressing intake air in a turbocharger upstream of the air/fuel injection. This process boosts the power output of the engine. The air compression increases the temperature of the intake air so an aftercooler is used to reduce the intake air temperature. Reducing the intake air temperature helps lower the peak flame temperature which reduces NOx formation in the combustion chamber. EU ID 8 is currently operating with a turbocharger and aftercooler. The Department considers turbocharger and aftercooler a technically feasible control technology for the large diesel-fired engine.

(c) Fuel Injection Timing Retard (FITR)
FITR reduces NOx emissions by the delay of the fuel injection in the engine from the time the compression chamber is at minimum volume to a time the compression chamber is expanding. Timing adjustments are relatively straightforward. The larger volume in the compression chamber produces a lower peak flame temperature. With the use of FITR the engine becomes less fuel efficient, particular matter emissions increase, and there is a limit with respect to the degree the timing may be retarded because an excessive timing delay can cause the engine to misfire. The timing retard is generally limited to no more than three degrees. Diesel engines may also produce more black smoke due to a decrease in exhaust temperature and incomplete combustion. FITR can achieve up to 50 percent NOx

reduction. Due to the increase in particulate matter emissions resulting from FITR, this technology will not be carried forward.

(d) Ignition Timing Retard (ITR)
ITR lowers NOx emissions by moving the ignition event to later in the power stroke, after the piston has begun to move downward. Because the combustion chamber volume is not at a minimum, the peak flame temperature is not as high, which lowers combustion temperature and produces less thermal NOx. Use of ITR can cause an increase in fuel usage, an increase PM emissions, and engine misfiring. ITR can achieve between 20 to 30 percent NOx reduction. Due to the increase in the particulate matter emissions resulting from ITR, this technology will not be carried forward.

(e) Federal Standard
RBLC NOx determinations for federal emission standards require the engines meet the requirements of 40 C.F.R. 60 NSPS Subpart IIII, 40 C.F.R 63 Subpart ZZZZ, non-road engines (NREs), or EPA tier certifications. NSPS Subpart IIII applies to stationary compression ignition internal combustion engines that are manufactured or reconstructed after July 11, 2005. EU 8 was manufactured prior to July 11, 2005 and has not been reconstructed since. Therefore, EU 8 is not subject to NSPS Subpart IIII. EU 8 is considered an institutional emergency engine and is therefore exempt from NESHAP Subpart ZZZZ. For these reasons federal emission standards will not be carried forward as a control technology.

(f) Limited Operation
EU 8 currently operates under a combined annual NOx emission limit with EU 4. Limiting the operation of emissions units reduces the potential to emit of those units. The Department considers limited operation a technically feasible control technology for the large diesel-fired engine.

(g) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the large dual fuel-fired boiler and will not be repeated here. The Department considers GCPs a technically feasible control technology for the large diesel-fired engine.

Step 2 - Eliminate Technically Infeasible NOx Control Technologies for the Large Engine
As explained in Step 1 of Section 3.4, the Department does not consider fuel injection timing retard, ignition timing retard, and federal emissions standards as technically feasible technologies to control NOx emissions from the large diesel-fired engine.

Step 3 - Rank the Remaining NOx Control Technologies for the Large Diesel-Fired Engine
The following control technologies have been identified and ranked by efficiency for the control of NOx emissions from the large diesel-fired engine.

(g)	Good Combustion Practices	(Less than 40% Control)
(a)	Selective Catalytic Reduction	(0% Control)
(b)	Turbocharger and Aftercooler	(0% Control)

(f) Limited operation (0% Control)

Control technologies already in practice at the stationary source or included in the design of the EU are considered 0% control for the purpose of the SIP BACT for existing stationary sources.

Step 4 - Evaluate the Most Effective Controls

UAF BACT Proposal

UAF proposes the following as BACT for NOx emissions from the large diesel-fired engine:

(a) NOx emissions from the operation of the large diesel-fired engine shall be controlled with limited use of the unit;

(b) NOx emissions from the operation of the large diesel-fired engine shall be controlled by operating a turbocharger and aftercooler;

(c) NOx emissions from the large diesel-fired engine shall not exceed 0.0195 g/hp-hr; and

(d) Combined NOx emissions from EUs 4 and 8 shall not exceed 40 tons per 12 month rolling period; and

(e) Maintain good combustion practices by following the manufacturer's operational procedures at all times of operation.

Department Evaluation of BACT for NOx Emissions from the Large Diesel-Fired Engine

The Department reviewed UAF's proposal and found that in addition to a turbocharger and aftercooler, and limited operation (all currently in practice), SCR (currently installed but not operating) and good combustion practices are also BACT for the control of NOx emissions from the large diesel-fired engine.

Step 5 - Selection of NOx BACT for the Large Diesel-Fired Engine

The Department's finding is that the BACT for NOx emissions from the large diesel-fired engine is as follows:

(a) NOx emissions from EU 8 shall be controlled by operating SCR, and a turbocharger and aftercooler at all times of operation;

(b) Limit non-emergency operation of EU 8 to no more than 100 hours per year for maintenance checks and readiness testing;

(c) NOx emissions from the large diesel-fired engine shall not exceed 1.3 g/hp-hr[11] averaged over a 3-hour period;

(d) Combined NOx emissions from EUs 4 and 8 shall not exceed 40 tons per 12 month rolling period; and

(e) Maintain good combustion practices by following the manufacturer's operational procedures at all times of operation.

Table 3-13 lists the proposed BACT determination for this facility along with those for other diesel-fired engines rated at more than 500 hp located in the Serious PM-2.5 nonattainment area.

[11] Worst-case NOx emissions rate from February 1, 2002 source test report while EU 8 was operating with SCR.

Table 3-13. Comparison of NOx BACT for Large Diesel-Fired Engines at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
Fort Wainwright	8 Large Diesel-Fired Engines	> 500 hp	3.0 – 10.9 g/hp-hr	Limited Operation Good Combustion Practices Federal Emission Standards
UAF	Large Diesel-Fired Engine	13,266 hp	1.3 g/hp-hr	Selective Catalytic Reduction Turbocharger and Aftercooler Good Combustion Practices Limited Operation
GVEA North Pole	Large Diesel-Fired Engine	600 hp	10.9 g/hp-hr	Turbocharger and Aftercooler Good Combustion Practices Limited Operation
GVEA Zehnder	2 Large Diesel-Fired Engines	11,000 hp (each)	10.9 g/hp-hr	Turbocharger and Aftercooler Good Combustion Practices Limited Operation

3.5 NOx BACT for the Small Diesel-Fired Engines (EUs 23, 24, and 26 – 29)

Possible NOx emission control technologies for small engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 17.210, Small Internal Combustion Engines (<500 hp). The search results for small diesel-fired engines are summarized in Table 3-14.

Table 3-14. RBLC Summary for NOx Control for Small Diesel-Fired Engines

Control Technology	Number of Determinations	Emission Limits (g/hp-hr)
Federal Emission Standards	5	2.2 – 4.8
Good Combustion Practices	25	2.0 – 9.5
Limited Operation	4	3.0
No Control Specified	25	2.6 – 5.6

RBLC Review

A review of similar units in the RBLC indicates limited operation, good combustion practices, and compliance with the federal emission standards are the principle NOx control technologies for small diesel-fired engines. The lowest NOx emission rate listed in the RBLC is 2.0 g/hp-hr

Step 1 - Identification of NOx Control Technology for the Small Diesel-Fired Engine

From research, the Department identified the following technologies as available for NOx control of the small diesel-fired engines:

(a) Selective Catalytic Reduction
The theory of SCR was discussed in detail in the NOx BACT for the large dual fuel-fired boiler and will not be repeated here. The Department considers SCR a technically feasible control technology for the small diesel-fired engines.

(b) Turbocharger and Aftercooler
The theory of a turbocharger and aftercooler was discussed in detail in the NOx BACT for the large diesel-fired engine and will not be repeated here. EU 27 currently operates with a turbocharger and aftercooler. The Department considers a turbocharger and aftercooler a technically feasible control technology for the small diesel-fired engines.

(c) Ignition Timing Retard (ITR)
The theory of ITR was discussed in detail in the NOx BACT for the large diesel-fired engine and will not be repeated here. Due to the increase in particulate matter emissions resulting from ITR, this technology will not be carried forward.

(d) Federal Emission Standards
RBLC NOx determinations for federal emission standards require the engines meet the requirements of 40 C.F.R. 60 Subpart IIII, 40 C.F.R 63 Subpart ZZZZ, non-road engines (NREs), or EPA tier certifications. Subpart IIII applies to stationary compression ignition internal combustion engines that are manufactured or reconstructed after July 11, 2005. The Department considers meeting the technology based NSPS of Subpart IIII as a technically feasible control technology for the small diesel-fired engines.

(e) Limited Operation
EU 27 currently operates under an owner requested limit of 4,380 hours of operation per 12 month rolling period, and EUs 24, 28, and 29 are considered emergency engines with 100 hour limits per calendar year for non-emergency operations. Limiting the operation of emission units reduces the potential to emit for those units. The Department considers limited operation as a technically feasible control technology for the small diesel-fired engines.

(f) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the large dual fired boiler and will not be repeated here. The Department considers GCPs a technically feasible control technology for the small diesel-fired engines.

Step 2 - Eliminate Technically Infeasible NOx Control Technologies for the Small Engines
As explained in Step 1 of Section 3.5, the Department does not consider ignition timing retard as a technically feasible technology to control NOx emissions from the small diesel-fired engines.

Step 3 - Rank the Remaining NOx Control Technologies for the Small Diesel-Fired Engines
The following control technologies have been identified and ranked by efficiency for the control of NOx emissions from the small diesel-fired engines.

(a)	Selective Catalytic Reduction	(90% Control)
(f)	Good Combustion Practices	(Less than 40% Control)
(d)	Federal Emission Standards	(Baseline)
(b)	Turbocharger and Aftercooler	(0% Control)
(e)	Limited Operation	(0% Control)

Control technologies already in practice at the stationary source or included in the design of the EU are considered 0% control for the purpose of the SIP BACT for existing stationary sources.

Step 4 - Evaluate the Most Effective Controls

UAF BACT Proposal

UAF provided an economic analysis of the installation of SCR on EU 27. A summary of the analysis is shown below:

Table 3-15. Economic Analysis for Technically Feasible NOx Controls

Control Alternative	Captured Emissions (tpy)	Emission Reduction (tpy)	Capital Cost ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR	0.8	6.9	$151,592	$84,544	$12,200
Capital Recovery Factor = 0.1424 (7% interest rate for a 10 year equipment life)					

UAF contends that the economic analysis indicates the level of NOx reduction does not justify the use of SCR based on the excessive cost per ton of NOx removed per year.

UAF proposes the following as BACT for NOx emissions from the small diesel-fired engine EU 27:

(a) NOx emissions from the operation of the small diesel-fired engine shall be controlled with limited use of the unit;

(b) NOx emissions from the operation of the small diesel-fired engine shall be controlled by complying with the federal standards under 40 C.F.R. 63 Subpart ZZZZ;

(c) NOx emissions from the operation of the small diesel-fired engine shall be controlled by operating a turbocharger and aftercooler;

(d) Maintain good combustion practices by following the manufacturer's operational procedures at all times of operation;

(e) NOx emissions from the small diesel-fired engine shall not exceed 3.20 g/hp-hr; and

(f) Operating hours for the small diesel-fired engine shall not exceed 4,380 hours per year.

Department Evaluation of BACT for NOx Emissions from the Small Diesel-Fired Engine

The Department revised the cost analysis provided by UAF for the installation of SCR on EU 27 to a 20 year equipment life. A summary of the analysis is shown below:

Table 3-16. Department Economic Analysis for Technically Feasible NOx Controls

Control Alternative	Captured Emissions (tpy)	Emission Reduction (tpy)	Capital Cost ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR	0.8	6.9	$151,592	$84,544	$11,141

Capital Recovery Factor = 0.094 (7% for a 20 year life cycle)

The Department's economic analysis indicates the level of NOx reduction does not justify installing SCR as BACT for the small diesel-fired engine EU 27 in the Serious PM-2.5 nonattainment area.

Step 5 - Selection of NOx BACT for the Small Diesel-Fired Engines
The Department's finding is that BACT for NOx emissions from the small diesel-fired engines is as follows:

(a) NOx emissions from EU 27 shall be controlled by operating a turbocharger and aftercooler at all times of operation;

(b) Limit the operation of EU 27 to no more than 4,380 hours per year;

(c) Limit non-emergency operation of EUs 24, 28, and 29 to no more than 100 hours per year each for maintenance checks and readiness testing;

(d) Maintain good combustion practices by following the manufacturer's operational procedures at all times of operation; and

(e) Comply with the numerical BACT emission limits listed in Table 3-17.

Table 3-17. Proposed NOx BACT Limits for the Small Diesel-Fired Engines

EU	Year	Description	Size	Status	BACT Limit	Proposed BACT
23	2003	Detroit Diesel	235 kW	AP-42 Table 3.3-1	14.1 g/hp-hr	Good Combustion Practices
26	1987	Mitsubishi-Bosh	45 kW	AP-42 Table 3.3-1	14.1 g/hp-hr	
27	TBD	Caterpillar C-15	500 hp	Certified Engine	3.2 g/hp-hr	Limit Operation to 4,380 hours per year, Turbo Charger and Aftercooler, & Good Combustion Practices
24	2001	Cummins	51 kW	AP-42 Table 3.3-1	14.1 g/hp-hr	Limit Operation for non-emergency use (100 hours each per year) and Good Combustion Practices
28	1998	Detroit Diesel	120 hp	AP-42 Table 3.3-1	14.1 g/hp-hr	
29	2013	Cummins	314 hp	Certified Engine	0.3 g/hp-hr	

Table 3-18 lists the proposed BACT determination for this facility along with those for other diesel-fired engines rated at less than 500 hp located in the Serious PM-2.5 nonattainment area.

Table 3-18. Comparison of NOx BACT for the Small Diesel-Fired Engines at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
UAF	Six Small Diesel-Fired Engines	< 500 hp	0.3 – 14.1 lb/hp-hr	Turbocharger and Aftercooler Good Combustion Practices Limited Operation
Fort Wainwright	41 Small Diesel-Fired Engines	< 500 hp	3.0 – 14.1 lb/hp-hr	40 CFR 60 Subpart IIII & Limited Operation

3.6 NOx BACT for the Pathogenic Waste Incinerator (EU 9A)

Possible NOx emission control technologies for pathogenic waste incinerators were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 21.300, Hospital, Medical, and Infectious Waste Incinerator. The search results for the pathogenic waste incinerators are summarized in Table 3-19.

Table 3-19. RBLC Summary of NOx Control for Pathogenic Waste Incinerators

Control Technology	Number of Determinations	Emission Limits (lb/hr)
Multiple Chamber Design	1	0.0900

RBLC Review
The RBLC has one entry for medical waste incinerators. The lowest emission rate listed in the RBLC is 0.0900 lb/hr.

Step 1 - Identification of NOx Control Technology for the Pathogenic Waste Incinerator
From research, the Department identified the following technologies as available for control of NOx emissions from pathogenic waste incinerators:

(a) Selective Catalytic Reduction
The theory of SCR was discussed in detail in the NOx BACT for the large dual fuel-fired boiler and will not be repeated here. The Department considers SCR a technically feasible control technology for the pathogenic waste incinerator.

(b) Selective Non-Catalytic Reduction
The theory of SNCR was discussed in detail in the NOx BACT for the large dual fuel-fired boiler and will not be repeated here. The Department considers SNCR a technically feasible control technology for the pathogenic waste incinerator.

(c) Limited Operation
EU 9A is currently operating under an owner requested limit to combust no more than 109 tons of waste per 12 month rolling period. With this limit NOx emissions for EU 9A are 0.2 tpy. The Department considers limited operation a technically feasible control technology for the pathogenic waste incinerator.

(d) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the large dual fuel-fired boiler and will not be repeated here. The Department considers GCPs a technically feasible control technology for the pathogenic waste incinerator.

Step 2 - Eliminate Technically Infeasible NOx Control Technologies for the Pathogenic Waste Incinerator
All control technologies are technically feasible. However, the Department finds that due to the limited NOx emissions from the pathogenic waste incinerator (0.2 tpy); SCR and SNCR will not be effective in reducing NOx emissions.

Step 3 - Rank the Remaining NOx Control Technologies for the Pathogenic Waste Incinerator

The following control technologies have been identified and ranked by efficiency for the control of NOx emissions from the pathogenic waste incinerator:

(d) Good Combustion Practices (Less than 40% Control)
(c) Limited Operation (0% Control)

Control technologies already in practice at the stationary source or included in the design of the EU are considered 0% control for the purpose of the SIP BACT for existing stationary sources.

Step 4 - Evaluate the Most Effective Controls

UAF BACT Proposal

UAF proposes the following as BACT for NOx emissions from the pathogenic waste incinerator:

(a) Limit the operation of pathogenic waste incinerator to no more than 109 tons of waste per 12 month rolling period;

(b) NOx emissions from the pathogenic waste incinerator shall not exceed 3.56 lb/ton;

(c) Compliance with the proposed operational limit will be demonstrated by recording pounds of waste combusted for the pathogenic waste incinerator; and

(d) Maintain good combustion practices.

Step 5 - Selection of NOx BACT for the Pathogenic Waste Incinerator

The Department's finding is that BACT for NOx emissions from the pathogenic waste incinerator is as follows:

(a) NOx emissions from EU 9A shall not exceed 3.56 lb/ton;

(b) Limit the operation of EU 9A to 109 tons of waste combusted per 12 month rolling period;

(c) Maintain good combustion practices by following the manufacturer's operational procedures at all times of operation; and

(d) Compliance with the proposed operational limit will be demonstrated by recording pounds of waste combusted for the pathogenic waste incinerator.

Table 3-20 lists the proposed BACT determination for this facility along with those for other waste incinerators located in the Serious PM-2.5 nonattainment area.

Table 3-20. Comparison of NOx BACT for Pathogenic Waste Incinerators at Nearby Power Plants

Facility	Process Description	Capacity	Limitation		Control Method
UAF	One Pathogenic Waste Incinerator	83 lb/hr	3.56	lb/ton	Limited Operation Good Combustion Practices

4. BACT DETERMINATION FOR PM-2.5

The Department based its PM-2.5 assessment on BACT determinations found in the RBLC, internet research, and BACT analyses submitted to the Department by GVEA for the North Pole Power Plant and Zehnder Facility, Aurora for the Chena Power Plant, US Army for Fort Wainwright, and UAF for the Combined Heat and Power Plant.

4.1 PM-2.5 BACT for the Large Dual Fuel-Fired Boiler (EU 113)

Possible PM-2.5 emission control technologies for large dual fuel-fired boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 11.110, Coal Combustion in Industrial Size Boilers and Furnaces. The search results are listed in Table 4-1.

Table 4-1. RBLC Summary of PM-2.5 Control for Industrial Coal-Fired Boilers

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Pulse Jet Fabric Filters	4	0.012 – 0.024
Electrostatic Precipitators	2	0.02 – 0.03

RBLC Review
A review of similar units in the RBLC indicates that fabric filters and electrostatic precipitators are the principle particulate matter control technologies installed on large dual fuel-fired boilers. The lowest PM-2.5 emission rate listed in RBLC is 0.012 lb/MMBtu.

Step 1 - Identification of PM-2.5 Control Technologies for the Large Dual Fuel-Fired Boiler
From research, the Department identified the following technologies as available for control of PM-2.5 emissions from the large dual fuel-fired boiler:

(a) Fabric Filters
Fabric filters or baghouses are comprised of an array of filter bags contained in housing. Air passes through the filter media from the "dirty" to the "clean" side of the bag. These devices undergo periodic bag cleaning based on the build-up of filtered material on the bag as measured by pressure drop across the device. The cleaning cycle is set to allow operation within a range of design pressure drop. Fabric filters are characterized by the type of cleaning cycle: mechanical-shaker,[12] pulse-jet,[13] and reverse-air.[14] Fabric filter systems have control efficiencies of 95% to 99.9%, and are generally specified to meet a discharge concentration of filterable particulate (e.g., 0.01 grains per dry standard cubic feet). The Department considers fabric filters a technically feasible control technology for the large dual fuel-fired boiler.

(b) Wet and Dry Electrostatic Precipitators (ESP)
ESPs remove particles from a gas stream by electrically charging particles with a discharge electrode in the gas path and then collecting the charged particles on grounded plates. The inlet air is quenched with water on a wet ESP to saturate the gas stream and ensure a wetted surface on the collection plate. This wetted surface along with a period deluge of water is what cleans the collection plate surface. Wet ESPs typically control streams with inlet grain loading values of 0.5 – 5 gr/ft^3 and have control efficiencies between 90% and 99.9%.[15] Wet ESPs have the advantage of controlling some amount of condensable particulate

[12] https://www3.epa.gov/ttn/catc/dir1/ff-shaker.pdf
[13] https://www3.epa.gov/ttn/catc/dir1/ff-pulse.pdf
[14] https://www3.epa.gov/ttn/catc/dir1/ff-revar.pdf
[15] https://www3.epa.gov/ttn/catc/dir1/fwespwpi.pdf
https://www3.epa.gov/ttn/catc/dir1/fwespwpl.pdf

matter. The collection plates in a dry ESP are periodically cleaned by a rapper or hammer that sends a shock wave that knocks the collected particulate off the plate. Dry ESPs typically control streams with inlet grain loading values of 0.5 – 5 gr/ft^3 and have control efficiencies between 99% and 99.9%.[16] The Department considers ESP a technically feasible control technology for the large dual fuel-fired boiler.

(c) Wet Scrubbers
Wet scrubbers use a scrubbing solution to remove $PM/PM_{10}/PM_{2.5}$ from exhaust gas streams. The mechanism for particulate collection is impaction and interception by water droplets. Wet scrubbers are configured as counter-flow, cross-flow, or concurrent flow, but typically employ counter-flow where the scrubbing fluid is in the opposite direction as the gas flow. Wet scrubbers have control efficiencies of 50% - 99%.[17] One advantage of wet scrubbers is that they can be effective on condensable particulate matter. A disadvantage of wet scrubbers is that they consume water and produce water and sludge. For fine particulate control, a venturi scrubber can be used, but typical loadings for such a scrubber are 0.1-50 grains/scf. The Department considers the use of wet scrubbers to be a technically feasible control technology for the large dual fuel-fired boiler.

(d) Cyclone
Cyclones are used in industrial applications to remove particulate matter form exhaust flows and other industrial stream flows. Dirty air enters a cyclone tangentially and the centrifugal force moves the particulate matter against the cone wall. The air flows in a helical pattern from the top down to the narrow bottom before exiting the cyclone straight up the center and out the top. Large and dense particles in the stream flow are forced by inertia into the walls of the cyclone where the material then falls to the bottom of the cyclone and into a collection unit. Cleaned air then exits the cyclone either for further treatment or release to the atmosphere. The narrowness of the cyclone wall and the speed of the air flow determine the size of particulate matter that is removed from the stream flow. Cyclones are most efficient at removing large particulate matter (PM-10 or greater). Conventional cyclones are expected to achieve 0 to 40 percent PM-2.5 removal. High efficiency single cyclones are expected to achieve 20 to 70 percent PM-2.5 removal. The Department considers cyclones a technically feasible control technology for the large dual fuel-fired boiler.

[16] https://www3.epa.gov/ttn/catc/dir1/fdespwpi.pdf
https://www3.epa.gov/ttn/catc/dir1/fdespwpl.pdf
[17] https://www3.epa.gov/ttn/catc/dir1/fcondnse.pdf
https://www3.epa.gov/ttn/catc/dir1/fiberbed.pdf
https://www3.epa.gov/ttn/catc/dir1/fventuri.pdf

(e) Settling Chamber

Settling chambers appear only in the biomass fired boiler RBLC inventory for particulate control, not in the coal fired boiler RBLC inventory. This type of technology is a part of the group of air pollution control collectively referred to as "pre-cleaners" because the units are often used to reduce the inlet loading of particulate matter to downstream collection devices by removing the larger, abrasive particles. The collection efficiency of settling chambers is typically less than 10 percent for PM-10. The EPA fact sheet does not include a settling chamber collection efficiency for PM-2.5. The Department does not consider settling chambers a technically feasible control technology for the large dual fuel-fired boiler.

(f) Good Combustion Practices

The theory of GCPs was discussed in detail in the NOx BACT for the large dual fuel-fired boiler and will not be repeated here. Proper management of the combustion process will result in a reduction of PM-2.5 emissions. The Department considers GCPs a technically feasible control technology for the large dual fuel-fired boiler.

Step 2 - Elimination of Technically Infeasible PM-2.5 Control Technologies for the Large Dual Fuel-Fired Boiler

As explained in Step 1 of Section 4.1, the Department does not consider a settling chamber a technically feasible control technology to control PM-2.5 emissions from the large dual fuel-fired boiler.

Step 3 - Rank the Remaining PM-2.5 Control Technologies for the Large Dual Fired Boiler

The following control technologies have been identified and ranked by efficiency for the control of PM-2.5 from the dual fuel-fired boiler:

(a) Fabric Filters	(99.9% Control)
(b) Electrostatic Precipitator	(99.6% Control)
(c) Scrubber	(50% - 99% Control)
(d) Cyclone	(20% - 70%)
(f) Good Combustion Practices	(Less than 40%)

Step 4 - Evaluate the Most Effective Controls

UAF BACT Proposal

UAF proposes the following as BACT for PM-2.5 emissions from the large dual fuel-fired boiler:

(a) PM-2.5 emissions shall be controlled by installing, operating, and maintaining a fabric filter; and

(b) PM-2.5 emissions shall not exceed 0.012 lb/MMBtu.

Step 5 - Selection of PM-2.5 BACT for the Large Dual Fuel-Fired Boiler

The Department's finding is that BACT for PM-2.5 emissions from the large dual fuel-fired boilers is as follows:

(a) PM-2.5 emissions from EU 113 shall be controlled by operating and maintaining fabric filters at all times of operation;

(b) PM-2.5 emissions from EU 113 shall not exceed 0.006 lb/MMBtu[18];

(c) Maintain good combustion practices at all times of operation by following the manufacturer's operating and maintenance procedures; and

(d) Initial compliance with the proposed PM-2.5 emission limit will be demonstrated by conducting a performance test to obtain an emission rate.

Table 4-2 lists the proposed PM-2.5 BACT determination for this facility along with those for other industrial coal-fired boilers in the Serious PM-2.5 nonattainment area.

Table 4-2. Comparison of PM-2.5 BACT for Coal-Fired Boilers at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
UAF	One Dual Fuel-Fired Boiler	295.6 MMBtu/hr	0.006 lb/MMBtu[18]	Fabric Filters
Fort Wainwright	Six Coal-Fired Boilers	1,380 MMBtu/hr	0.006 lb/MMBtu[18]	Full Steam Baghouse

4.2 PM-2.5 BACT for the Mid-Sized Diesel-Fired Boilers (EUs 3 and 4)

Possible PM-2.5 emission control technologies for mid-sized diesel-fired boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 12.220, Industrial Size Distillate Fuel Oil Boilers (>100 MMBtu/hr and ≤ 250 MMBtu/hr). The search results for mid-sized diesel-fired boilers are summarized in 4-3.

Table 4-3. RBLC Summary of PM-2.5 Control for Mid-Sized Boilers Firing Diesel

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
No Control Specified	7	0.0066 – 0.02
Good Combustion Practices	3	0.007 – 0.015

Possible PM-2.5 emission control technologies for mid-sized diesel-fired boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 12.310, Industrial Size Gaseous Fuel Boilers (>100 MMBtu/hr and ≤ 250 MMBtu/hr). The search results for mid-sized diesel-fired boilers are summarized in Table 4-4.

Table 4-4. RBLC Summary of PM-2.5 Control for Mid-Sized Boilers Firing Natural Gas

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Limited Operation	2	0.0074 - 0.3
Good Combustion Practices	42	0.0019 – 0.008
No Control Specified	19	0.0074 – 0.01

RBLC Review

A review of similar units in the RBLC indicates limited operation and good combustion practices are the principle PM-2.5 control technologies installed on mid-sized boilers. The lowest PM-2.5 emission rate listed in the RBLC is 0.0019 lb/MMBtu.

[18] Average soot blown emission rate (rounded up) from worst coal-fired boiler tested at Fort Wainwright (Boiler No. 3) during most recent source test on April 19-22, 24, and 25, 2017.

Step 1 - Identification of PM-2.5 Control Technology for the Mid-Sized Diesel-Fired Boilers
From research, the Department identified the following technologies as available for PM-2.5 control of mid-sized diesel-fired boilers:

(a) Fabric Filters
The theory behind fabric filters was discussed in detail in the PM-2.5 BACT for the large dual fuel-fired boiler and will not be repeated here. The Department considers fabric filters a technically feasible control technology for the mid-sized diesel-fired boilers.

(b) Electrostatic Precipitators
The theory behind ESPs was discussed in detail in the PM-2.5 BACT for the large dual fuel-fired boiler and will not be repeated here. The Department considers ESPs a technically feasible control technology for the mid-sized diesel-fired boilers.

(c) Scrubber
The theory behind scrubbers was discussed in detail in the PM-2.5 BACT for the large dual fuel-fired boiler and will not be repeated here. The Department considers scrubbers a technically feasible control technology for the mid-sized diesel-fired boilers.

(d) Cyclone
The theory behind cyclones was discussed in detail in the PM-2.5 BACT for the large dual fuel-fired boiler and will not be repeated here. The Department considers cyclones a technically feasible control technology for the mid-sized diesel-fired boilers.

(e) Natural Gas
The theory behind the use of natural gas for the mid-sized diesel-fired boilers was discussed in detail in the NOx BACT for the mid-sized diesel-fired boilers. The Department does not consider switching to natural gas a technically feasible control technology for the mid-sized diesel-fired boilers.

(f) Limited Operation
The theory behind limited operation for EUs 3 and 4 was discussed in detail in the NOx BACT for the mid-sized diesel-fired boilers and will not be repeated here. The Department considers limited operation a technically feasible control technology for the mid-sized diesel-fired boilers.

(g) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the large dual fuel-fired boiler and will not be repeated here. Proper management of the combustion process will result in a reduction of PM-2.5 emissions. The Department considers GCPs a technically feasible control technology for the mid-sized diesel-fired boilers.

Step 2 - Eliminate Technically Infeasible PM-2.5 Control Technologies for the Mid-Sized Diesel-Fired Boilers

As explained in Step 1 of Section 4.2, the Department does not consider natural gas as a technically feasible technology to control particulate matter emissions from the mid-sized diesel-fired boilers.

Additionally, due to the residue from the diesel combustion in the exhaust gas, fabric filters, scrubbers, ESPs, and cyclones are not technically feasible control technologies.

EU 3 is used as a backup to the existing large boilers if one of them fails, and will be used as the backup to EU 113 if it fails. As the backup EU, it is not technically feasible to use an operational limit to control PM-2.5 emissions.

Step 3 - Rank the Remaining PM-2.5 Control Technologies for the Mid-Sized Diesel-Fired Boilers
UAF has selected the only remaining control technologies, therefore, ranking is not required.

Step 4 - Evaluate the Most Effective Controls

UAF BACT Proposal

UAF proposes the following as BACT for the mid-sized diesel-fired boilers:

(a) PM-2.5 emissions from EU 3 and 4 shall not exceed 0.016 lb/MMBtu while firing diesel fuel;

(b) PM-2.5 emissions from EU 4 shall not exceed 7.6 lb/MMscf while firing natural gas; and

(c) PM-2.5 emissions from EU 4 will be limited by complying with the combined annual NOx emission limit of 40 tons per 12 month rolling period for EUs 4 and 8.

Step 5 - Selection of PM-2.5 BACT for the Mid-Sized Diesel-Fired Boilers
The Department's finding is that BACT for PM-2.5 emissions from EUs 3 and 4 is as follows:

(a) PM-2.5 emissions from EUs 3 and 4 shall not exceed 0.012 lb/MMBtu[19] averaged over a 3-hour period while firing diesel fuel;

(b) PM-2.5 emissions from EU 4 shall not exceed 0.0075 lb/MMBtu[20] averaged over a 3-hour period while firing natural gas;

(c) PM-2.5 emissions from EU 4 shall be controlled by limiting combined NOx emissions of EU 4 and 8 to no more than 40 tons per 12 month rolling period;

(d) Maintain good combustion practices by following the manufacturer's operational procedures at all times of operation.

Table 4-5 lists the proposed BACT determination for the facility.

Table 4-5. PM-2.5 BACT Limits for the Mid-Sized Diesel-Fired Boilers

Facility	EU ID	Process Description	Capacity	Fuel	Limitation	Control Method
UAF	3	Dual Fuel-Fired Boilers	100 – 250 MMBtu/hr	Diesel	0.012 lb/MMBtu[19]	Good Combustion Practices
	4			Diesel	0.012 lb/MMBtu[19]	Limited Operation

[19] Emission factor from AP-42 Table's 1.3-2 (total condensable particulate matter from No. 2 oil, 1.3 lb/1,000 gal) and 1.3-6 (PM-2.5 size-specific factor from distillate oil, 0.25 lb/1,000 gal) converted to lb/MMBtu.
[20] Emission factor from AP-42 Table 1.4-2 for total particulate matter and converted to lb/MMBtu.

				Natural Gas	0.0075 lb/MMBtu[20]	Good Combustion Practices

4.3 PM-2.5 BACT for the Small Diesel-Fired Boilers (EUs 19 through 21)

Possible PM-2.5 emission control technologies for small diesel-fired boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 13.220, Commercial/Institutional Size Boilers (<100 MMBtu/hr). The search results for diesel-fired engines are summarized in Table 4-6.

Table 4-6. RBLC Summary of PM-2.5 Control for Small Diesel-Fired Boilers

Control Technology	Number of Determinations	Emission Limits
Good Combustion Practices	3	0.25 lb/gal
		0.1 tpy
		2.17 lb/hr

RBLC Review
A review of similar units in the RBLC indicates good combustion practices are the principle PM-2.5 control technologies installed on diesel-fired boilers. The lowest PM-2.5 emission rate listed in the RBLC is 0.1 tpy.

Step 1 - Identification of PM-2.5 Control Technology for the Small Diesel-Fired Boilers
From research, the Department identified the following technologies as available for control of PM-2.5 emissions from the small diesel-fired boilers:

(a) Scrubbers
The theory behind scrubbers was discussed in detail in the PM-2.5 BACT for the large dual fuel-fired boiler and will not be repeated here. The Department considers scrubbers as a technically feasible control technology for the small diesel-fired boilers.

(b) Limited Operation
The theory behind limited operation was discussed in detail in the NOx BACT for the small diesel-fired boilers and will not be repeated here. The Department considers limited operation a technically feasible control technology for the small diesel-fired boilers.

(c) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the large dual fuel-fired boiler and will not be repeated here. Proper management of the combustion process will result in a reduction of PM-2.5 emissions. The Department considers GCPs a technically feasible control technology for the small diesel-fired boilers.

Step 2 - Eliminate Technically Infeasible PM-2.5 Control Technologies for the Diesel-Fired Boilers
All identified control devices are technically feasible for the small diesel-fired boilers.

Step 3 - Rank the Remaining PM-2.5 Control Technologies for the Small Diesel-Fired Boilers

The following control technologies have been identified and ranked by efficiency for the control of PM-2.5 emissions from the small diesel-fired boilers:

(a) Scrubber (70% - 90% Control)
(c) Good Combustion Practices (Less than 40% Control)
(b) Limited Operation (0% Control)

Control technologies already in practice at the stationary source or included in the design of the EU are considered 0% control for the purpose of the SIP BACT for existing stationary sources.

Step 4 - Evaluate the Most Effective Controls

UAF BACT Proposal

UAF provided an economic analysis of the installation of a scrubber. A summary of the analysis is shown below:

Table 4-7. UAF Economic Analysis for Technically Feasible PM-2.5 Controls

Control Alternative	Captured Emissions (tpy)	Emission Reduction (tpy)	Capital Cost ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Scrubber	0.01	0.93	$300,000	$42,713	$47,939
Capital Recovery Factor = 0.1424 (7% for a 10 year life cycle)					

UAF contends that the economic analysis indicates the level of PM-2.5 reduction does not justify the use of a scrubber to be used in conjunction with limited operation on the small diesel-fired boilers based on the excessive cost per ton of PM-2.5 removed per year.

UAF proposes the following as BACT for PM-2.5 emissions for the small diesel-fired boilers:

(a) PM-2.5 emissions from the operation of the small diesel-fired boilers will be controlled by limiting the combined operation to no more than 19,650 hours per 12-month rolling period; and

(b) PM-2.5 emissions from the small diesel-fired boilers shall not exceed 7.06 g/MMBtu.

Department Evaluation of BACT for PM-2.5 Emissions from the Small Diesel-Fired Boilers.

The Department reviewed UAF's proposal and finds that the 3 small diesel-fired boilers have a combined potential to emit (PTE) of less than one ton per year (tpy) for PM-2.5 based on a limit on operation of 19,650 hours per 12 month rolling period. The Department does not agree with all of the assumptions made by UAF in their cost analysis. However, the Department believes that at 0.9 tpy, the cost effectiveness in terms of dollars per ton for add-on pollution control for these units is economically infeasible.

Step 5 - Selection of PM-2.5 BACT for the Small Diesel-Fired Boilers

The Department's finding is that BACT for PM-2.5 emissions from the diesel-fired boilers is as follows:

(a) PM-2.5 emissions from the operation of the small diesel-fired boilers will be controlled by limiting the combined operation to no more than 19,650 hours per 12-month rolling period;
(b) PM-2.5 emissions from EUs 19 through 21 shall not exceed 0.012 lb/MMBtu[19]; and
(c) Maintain good combustion practices by following the manufacturer's operational procedures at all times of operation.

Table 4-8 lists the proposed PM-2.5 BACT determination for this facility along with those for other small diesel-fired boilers rated at less than 100 MMBtu/hr in the Serious PM-2.5 nonattainment area.

Table 4-8. PM-2.5 BACT Limits for the Small Diesel-Fired Boilers

Facility	Process Description	Capacity	Limitation	Control Method
UAF	3 Diesel-Fired Boilers	< 100 MMBtu/hr	0.012 lb/MMBtu[19]	Limited Operation Good Combustion Practices
Fort Wainwright	27 Diesel-Fired Boilers	< 100 MMBtu/hr	0.012 lb/MMBtu[19]	Good Combustion Practices
Zehnder Facility	2 Diesel-Fired Boilers	< 100 MMBtu/hr	0.012 lb/MMBtu[19]	Good Combustion Practices

4.4 PM-2.5 BACT for the Large Diesel-Fired Engine (EU 8)

Possible PM-2.5 emission control technologies for large diesel-fired engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 17.110-17.190, Large Internal Combustion Engines (>500 hp). The search results for large diesel-fired engines are summarized in Table 4-9.

Table 4-9. RBLC Summary of PM-2.5 Control for the Large Diesel-Fired Engines

Control Technology	Number of Determinations	Emission Limits (g/hp-hr)
Federal Emission Standards	12	0.03 – 0.02
Good Combustion Practices	28	0.03 – 0.24
Limited Operation	11	0.04 – 0.17
Low Sulfur Fuel	14	0.15 – 0.17
No Control Specified	14	0.02 – 0.15

RBLC Review

A review of similar units in the RBLC indicates that good combustion practices, compliance with the federal emission standards, low ash/sulfur diesel, and limited operation are the principle PM-2.5 control technologies installed on large diesel-fired engines. The lowest PM-2.5 emission rate in the RBLC is 0.02 g/hp-hr.

Step 1 - Identification of PM-2.5 Control Technology for the Large Diesel-Fired Engine

From research, the Department identified the following technologies as available for control of PM-2.5 emissions diesel-fired engines rated at 500 hp or greater:

(a) Diesel Particulate Filter (DPF)
DPF is a control technology that are designed to physically filter particulate matter from the exhaust stream. Several designs exist which require cleaning and replacement of the

filter media after soot has become caked onto the filter media. Regenerative filter designs are also available that burn the soot on a regular basis to regenerate the filter media. The Department considers DPF a technically feasible control technology for the large diesel-fired engine.

(b) Positive Crankcase Ventilation
Positive crankcase ventilation is the process of re-introducing the combustion air into the cylinder chamber for a second chance at combustion after the air has seeped into and collected in the crankcase during the downward stroke of the piston cycle. This process allows any unburned fuel to be subject to a second combustion opportunity. Any combustion products act as a heat sink during the second pass through the piston, which will lower the temperature of combustion and reduce the thermal NOx formation. Positive crankcase ventilation is included in the design of EU 8. The Department considers positive crankcase ventilation a technically feasible control technology for the large diesel-fired engine.

(c) Diesel Oxidation Catalyst (DOC)
DOC can reportedly reduce PM-2.5 emissions by 30% and PM emissions by 50%. A DOC is a form of "bolt on" technology that uses a chemical process to reduce pollutants in the diesel exhaust into decreased concentrations. They replace mufflers on vehicles, and require no modifications. More specifically, this is a honeycomb type structure that has a large area coated with an active catalyst layer. As CO and other gaseous hydrocarbon particles travel along the catalyst, they are oxidized thus reducing pollution. The Department considers DOC a technically feasible control technology for the large diesel-fired engine.

(d) Low Ash Diesel
Residual fuels and crude oil are known to contain ash forming components, while refined fuels are low ash. Fuels containing ash can cause excessive wear to equipment and foul engine components. EU 8 is fired exclusively on distillate fuel which is a form of refined fuel. The potential PM-2.5 emissions are based on emission factors for distillate fuel. EU 8 is capable of firing either diesel or heavy fuel oil (non-low ash fuel) according to manufacturer specifications. The Department considers low ash diesel as a technically feasible control technology for the large diesel-fired engine.

(e) Federal Emission Standards
The theory behind the federal emission standards for EU 8 was discussed in detail in the NOx BACT for the large diesel-fired engine and will not be repeated here. Due to EU 8 not being subject to either 40 C.F.R. 60 Subpart IIII or 40 C.F.R. 63 Subpart ZZZZ the Department does not consider federal emission standards as a feasible control technology for the large diesel-fired engine.

(f) Limited Operation
The theory behind limited operation for EU 8 was discussed in detail in the NOx BACT for the large diesel-fired engine and will not be repeated here. Due to EUs 4 and 8 currently

operating under a combined NOx emission limit, the Department considers limited operation a technically feasible control technology for the large diesel-fired engine.

(g) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the large dual fuel-fired boiler and will not be repeated here. Proper management of the combustion process will result in a reduction of PM-2.5 emissions. The Department considers GCPs a technically feasible control technology for the large diesel-fired engine.

Step 2 - Eliminate Technically Infeasible PM-2.5 Control Technologies for the Large Engine
As explained in Step 1 of Section 4.4, the Department does not consider meeting the federal emission standards as a technically feasible technology to control PM-2.5 emissions from EU 8. Additionally, EU 8 is equipped with SCR for controlling NOx emissions, which creates a backpressure. This backpressure does not allow for the operation of a DPF. Therefore, a DPF is not a technically feasible PM-2.5 control option for the large diesel-fired engine.

Step 3 - Rank the Remaining PM-2.5 Control Technologies for the Large Diesel-Fired Engine
The following control technologies have been identified and ranked by efficiency for the control of PM-2.5 emissions from the large diesel-fired engines:

(g)	Good Combustion Practices	(Less than 40% Control)
(c)	Diesel Oxidation Catalyst	(30% Control)
(b)	Positive Crankcase Ventilation	(~10% Control)
(d)	Low Ash/Sulfur Diesel	(~20% Control)
(f)	Limited Operation	(0% Control)

Control technologies already in practice at the stationary source or included in the design of the EU are considered 0% control for the purpose of the SIP BACT for existing stationary sources.

Step 4 - Evaluate the Most Effective Controls

UAF BACT Proposal

UAF proposes the following as BACT for PM-2.5 emissions from the large diesel-fired engine:

(a) PM-2.5 emissions from the large diesel-fired engine shall be controlled by operating with positive crankcase ventilation;

(b) PM-2.5 emissions shall not exceed 0.32 g/hp-hr;

(c) EU 8 shall combust only low ash diesel; and

(d) PM-2.5 emissions from EU 8 will be limited by complying with the combined annual NOx emission limit of 40 tons per 12 month rolling period for EUs 4 and 8.

Step 5 - Selection of PM-2.5 BACT for the Large Diesel-Fired Engine
The Department's finding is that the BACT for NOx emissions from the large diesel-fired engine is as follows:

(a) PM-2.5 emissions from EU 8 shall be controlled by operating positive crankcase ventilation at all time of operation;

(b) Limit non-emergency operation of EU 8 to no more than 100 hours per year for maintenance checks and readiness testing;

(c) Combined NOx emissions from EUs 4 and 8 shall not exceed 40 tons per rolling 12 month period;

(d) PM-2.5 emissions from EU 8 shall not exceed 0.32 g/hp-hr over a 3-hour period; and

(e) EU 8 shall combust only low ash diesel.

Table 4-10 lists the proposed BACT determination for this facility along with those for other diesel-fired engines rated at more than 500 hp located in the Serious PM-2.5 nonattainment area.

Table 4-10. Comparison of PM-2.5 BACT for the Large Diesel-Fired Engine at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
UAF	Large Diesel-Fired Engine	> 500 hp	0.32 g/hp-hr	Positive Crankcase Ventilation Limited Operation
Fort Wainwright	Large Diesel-Fired Engines	> 500 hp	0.15 – 0.32 g/hp-hr	Limited Operation Ultra-Low Sulfur Diesel Federal Emission Standards
GVEA North Pole	Large Diesel-Fired Engines	> 500 hp	0.32 g/hp-hr	Limited Operation Good Combustion Practices
GVEA Zehnder	Large Diesel-Fired Engines	> 500 hp	0.32 g/hp-hr	Limited Operation Good Combustion Practices

4.5 PM-2.5 BACT for the Small Diesel-Fired Engines (EUs 23, 24, and 26 – 29)

Possible PM-2.5 emission control technologies for small engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 17.210, Small Internal Combustion Engines (<500 hp). The search results for small diesel-fired engines are summarized in Table 4-11.

Table 4-11. RBLC Summary for PM-2.5 Control for the Small Diesel-Fired Engine

Control Technology	Number of Determinations	Emission Limits (g/hp-hr)
Federal Emission Standards	3	0.15
Good Combustion Practices	19	0.15 – 0.4
Limited Operation	7	0.15 – 0.17
Low Sulfur Fuel	7	0.15 – 0.3
No Control Specified	14	0.02 – 0.09

RBLC Review

A review of similar units in the RBLC indicates low ash/sulfur diesel, compliance with federal emission standards, limited operation, and good combustion practices are the principle PM-2.5 control technologies installed on small diesel-fired engines. The lowest PM-2.5 emission rate listed in the RBLC is 0.02 g/hp-hr.

Step 1 - Identification of PM-2.5 Control Technology for the Small Diesel-Fired Engines

From research, the Department identified the following technologies as available for control of PM-2.5 emissions from the diesel-fired engines rated at 500 hp or less:

(a) Diesel Particulate Filter
The theory behind DPF was discussed in detail in the PM-2.5 BACT for the large diesel-fired engine and will not be repeated here. The Department considers DPF a technically feasible control technology for the small diesel-fired engines.

(b) Diesel Oxidation Catalyst
The theory behind DOC was discussed in detail in the PM-2.5 BACT for the large diesel-fired engines and will not be repeated here. The Department considers DOC a technically feasible control technology for the small diesel-fired engines.

(c) Low Ash Diesel
Residual fuels and crude oil are known to contain ash forming components, while refined fuels are low ash. Fuels containing ash can cause excessive wear to equipment and foul engine components. The Department considers low ash diesel a technically feasible control technology for the small diesel-fired engines.

(d) Federal Emission Standards
The theory behind federal emission standards for the small diesel-fired engine was discussed in detail in the NOx BACT for the small diesel-fired engine and will not be repeated here. The Department considers federal emission standards a technically feasible control technology for the small diesel-fired engines.

(e) Limited Operation
The theory behind limited operation for the small diesel-fired engine was discussed in detail in the NOx BACT for the small diesel-fired engine and will not be repeated here. The Department considers limited operation a technically feasible control technology for the small diesel-fired engines.

(f) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the large dual fuel-fired boiler and will not be repeated here. Proper management of the combustion process will result in a reduction of PM-2.5 emissions. The Department considers GCPs a technically feasible control technology for the small diesel-fired engines.

Step 2 - Eliminate Technically Infeasible PM-2.5 Control Technologies for the Small Engines
All identified control technologies are technically feasible for the small diesel-fired engines.

Step 3 - Rank the Remaining PM-2.5 Control Technologies for the Small Diesel-Fired Engines
The following control technologies have been identified and ranked by efficiency for the control of PM-2.5 emissions from the small diesel-fired engines:

(a) Diesel Particulate Filter (60% - 90% Control)
(b) Diesel Oxidation Catalyst (40% Control)

(c) Low Ash/ Sulfur Diesel (25% Control)
(f) Good Combustion Practices (Less than 40% Control)
(d) Federal Emission Standards (0% Control)
(e) Limited Operation (0% Control)

Control technologies already in practice at the stationary source or included in the design of the EU are considered 0% control for the purpose of the SIP BACT for existing stationary sources.

Step 4 - Evaluate the Most Effective Controls

UAF BACT Proposal

UAF provided an economic analysis for the installation of DPF on EU 27. A summary of the analysis is shown below:

Table 4-12. UAF Economic Analysis for Technically Feasible PM-2.5 Controls

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
DPF	0.26	0.22	$30,751	$4,378	$17,169
Capital Recovery Factor = 0.1424 (7% interest rate for a 10 year equipment life)					

UAF contends that the economic analysis indicates the level of PM-2.5 reduction does not justify the use of DPF for EU 27 based on the excessive cost per ton of PM-2.5 removed per year.

UAF proposes the following as BACT for PM-2.5 emissions from the small diesel-fired engine EU 27:

(a) PM-2.5 emissions from EU 27 will be controlled by limiting the operation to no more than 4,380 hours per 12-month rolling period;

(b) Comply with the federal emission standards of NSPS Subpart IIII, Tier 3; and

(c) NOx emissions from EU 27 will not exceed 0.11 g/hp-hr.

Department Evaluation of BACT for NOx Emissions from the Small Diesel-Fired Engine

The Department revised the cost analysis provided by UAF for the installation of DPF on EU 27 using a 20 year equipment life. A summary of the analysis is shown below:

Table 4-13. Department Economic Analysis for Technically Feasible PM-2.5 Controls

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Capital Cost ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
DPF	0.26	0.22	$30,751	$2,891	$13,139
Capital Recovery Factor = 0.094 (7% interest rate for a 20 year equipment life)					

The Department's economic analysis economic analysis indicates the level of PM-2.5 reduction does not justify the use of a DPF to be used in conjunction with the federal emission standards and limited operation.

Step 5 - Selection of PM-2.5 BACT for the Small Diesel-Fired Engines
The Department's finding is that BACT for PM-2.5 emissions from the small diesel-fired engines is as follows:

(a) Limit operation of EU 27 to no more than 4,380 hours per 12-month rolling period;

(b) Limit non-emergency operation of EUs 24, 28, and 29 to no more than 100 hours per year each for maintenance checks and readiness testing;

(c) Maintain good combustion practices by following the manufacturer's operational procedures at all times of operation;

(d) EU 27 shall comply with the federal emission standards of NSPS Subpart IIII, Tier 3; and

(f) Comply with the numerical BACT emission limits listed in Table 4-14.

Table 4-14. Proposed PM-2.5 BACT Limits for the Small Diesel-Fired Engines

EU	Year	Description	Size	Status	BACT Limit	Proposed BACT
23	2003	Detroit Diesel	235 kW	AP-42 Table 3.3-1	1.0 g/hp-hr	Good Combustion Practices
26	1987	Mitsubishi-Bosh	45 kW	AP-42 Table 3.3-1	1.0 g/hp-hr	
27	TBD	Caterpillar C-15	500 hp	Certified Engine	0.11 g/hp-hr	Limit Operation to 4,380 hours per year, Turbo Charger and Aftercooler, & Good Combustion Practices
24	2001	Cummins	51 kW	AP-42 Table 3.3-1	1.0 g/hp-hr	Limit Operation for non-emergency use (100 hours each per year) and Good Combustion Practices
28	1998	Detroit Diesel	120 hp	AP-42 Table 3.3-1	1.0 g/hp-hr	
29	2013	Cummins	314 hp	Certified Engine	0.015 g/hp-hr	

Table 4-15 lists the proposed BACT determination for this facility along with those for other diesel-fired engines rated at less than 500 hp located in the Serious PM-2.5 nonattainment area.

Table 4-15. Comparison of PM-2.5 BACT for the Small Engines at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
UAF	Six Small Diesel-Fired Engine	< 500 hp	0.015 – 1.0 g/hp-hr	Good Combustion Practices Limited Operation
Fort Wainwright	41 Small Diesel-Fired Engines	< 500 hp	0.015 – 1.0 g/hp-hr	Good Combustion Practices Limited Operation

4.6 PM-2.5 BACT for the Pathogenic Waste Incinerator (EU 9A)

Possible PM-2.5 emission control technologies for waste incinerators were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 21.300 for Hospital, Medical and Infectious Waste Incinerators. The search results for pathogenic waste incinerators are summarized in Table 4-16.

Table 4-16. RBLC Summary of PM-2.5 Control for Pathogenic Waste Incinerator

Control Technology	Number of Determinations	Emission Limits (lb/hr)
Multiple Chamber Design	1	0.0400

RBLC Review
A review of similar units in the RBLC indicates multiple chamber design is the principle PM-2.5 control technology installed on pathogenic waste incinerators. The lowest emission rate listed in the RBLC is 0.0400 lb/hr

Step 1 - Identification of PM-2.5 Control Technology for the Pathogenic Waste Incinerator
From research, the Department identified the following technologies as available for control of PM-2.5 emissions from pathogenic waste incinerators:

(a) Fabric Filters
The theory behind fabric filters was discussed in detail in the PM-2.5 BACT for the large dual fuel-fired boiler and will not be repeated here. The Department considers fabric filters a technically feasible control technology for the pathogenic waste incinerator.

(b) ESPs
The theory behind ESPs was discussed in detail in the PM-2.5 BACT for the large dual fuel-fired boiler and will not be repeated here. The Department considers ESPs a technically feasible control technology for the pathogenic waste incinerator.

(c) Multiple Chambers
A multiple chamber incinerator introduces the waste material and a portion of the combustion air in the primary chamber. The waste material is combusted in the primary chamber. The secondary chamber introduces the remaining air to complete the combustion of all incomplete combustion products. Many of the volatile organic compounds from waste material are completely combusted in the secondary chamber. Solid waste incinerators can reduce PM-10 emissions up to 70 percent using multiple chambers. The expectation is that less than 70 percent control of PM-2.5 would be removed. The Department considers multiple chambers a technically feasible control technology for the pathogenic waste incinerator.

(d) Limited Operation
The theory behind the limited operation for EU 9A was discussed in detail in the NOx BACT for the pathogenic waste incinerator and will not be repeated here. The Department considers limited operation a technically feasible control technology for the pathogenic waste incinerator.

(e) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the large dual fuel-fired boiler and will not be repeated here. Proper management of the combustion process will result in a reduction of PM-2.5 emissions. The Department considers GCPs a technically feasible control technology for the pathogenic waste incinerator.

Step 2 - Eliminate Technically Infeasible PM-2.5 Controls for Pathogenic Waste Incinerator
The applicant provided information from the manufacturer of the pathogenic waste incinerator that an ESP is a technically infeasible PM-2.5 control for the pathogenic waste incinerator due to the high moisture content of the exhaust.

Step 3 - Rank the Remaining PM-2.5 Control Technologies for the Pathogenic Waste Incinerator
The following control technologies have been identified and ranked by efficiency for the control of PM-2.5 emissions from the pathogenic waste incinerator:

(a) Fabric Filter (99.9% Control)
(e) Good Combustion Practices (Less than 40% Control)
(c) Multiple Chambers (0% Control)
(d) Limited Operation (0% Control)

Control technologies already in practice at the stationary source or included in the design of the EU are considered 0% control for the purpose of the SIP BACT for existing stationary sources.

Step 4 - Evaluate the Most Effective Controls

UAF BACT Proposal

UAF provided an economic analysis for the installation of a fabric filter. A summary of the analysis is shown below:

Table 4-17. UAF Economic Analysis for Technically Feasible PM-2.5 Controls

Control Alternative	Captured Emissions (tpy)	Emission Reduction (tpy)	Capital Cost ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Fabric Filter	0.01	0.24	$1,300,000	$217,011	$761,441
Capital Recovery Factor = 0.1424 (7% interest rate for a 10 year equipment life)					

UAF contends that the economic analysis indicates the level of PM-2.5 reduction does not justify the use of a fabric filter in conjunction with the multiple chamber design and limited operation based on the excessive cost per ton of PM-2.5 removed per year.

UAF proposes the following as BACT for PM-2.5 emissions from the pathogenic waste incinerator:

(a) PM-2.5 emissions from the operation of EU 9A will be controlled with a multiple chamber design and by limiting operation to no more than 109 tons of waste combusted per 12-month rolling period;

(b) PM-2.5 emissions from EU 9A shall not exceed 4.67 lb/ton; and

(c) Compliance with the operating hours limit will be demonstrated by monitoring and recording the weight of waste combusted on a monthly basis.

Step 5 - Selection of PM-2.5 BACT for the Pathogenic Waste Incinerator
The Department's finding is that BACT for PM-2.5 emissions from the pathogenic waste incinerator is as follows:

(a) PM-2.5 emissions from EU 9A shall be controlled with a multiple chamber design;

(b) PM-2.5 emissions from EU 9A shall not exceed 4.67 lb/ton;

(c) Limit the operation of EU 9A to 109 tons of waste combusted per 12 month rolling period;

(d) Maintain good combustion practices by following the manufacturer's operational procedures at all times of operation; and
(e) Compliance with the proposed operational limit will be demonstrated by recording pounds of waste combusted for the pathogenic waste incinerator.

Table 4-18 lists the proposed BACT determination for this facility along with those for other waste incinerators located in the Serious PM-2.5 nonattainment area.

Table 4-18. Comparison of PM-2.5 BACT for Pathogenic Waste Incinerators at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
UAF	One Pathogenic Waste Incinerator	83 lb/hr	4.67 lb/ton	Multiple Chambers Good Combustion Practices Limited Operation

4.7 PM-2.5 BACT for the Material Handling Units (EUs 105, 107, 109 through 111, 114, and 128 through 130)

Possible PM-2.5 emission control technologies for material handling were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 99.100 - 190, Fugitive Dust Sources. The search results for material handling units are summarized in Table 4-19.

Table 4-19. PM-2.5 Control for Material Handling Units

Control Technology	Number of Determinations	Emission Limits
Fabric Filter / Baghouse	10	0.005 gr/dscf
Electrostatic Precipitator	3	0.032 lb/MMBtu
Wet Suppressants / Watering	3	29.9 tpy
Enclosures / Minimizing Drop Height	4	0.93 lb/hr

RBLC Review
A review of similar units in the RBLC indicates good operational practices, enclosures, fabric filters, and minimizing drop heights are the principle PM-2.5 control technologies for material handling operations.

Step 1 - Identification of PM-2.5 Control Technology for the Material Handling Units
From research, the Department identified the following technologies as available for PM-2.5 control of the material handling units:

(a) Fabric Filters
The theory behind fabric filters was discussed in detail in the PM-2.5 BACT for the large dual fuel-fired boiler and will not be repeated here. The Department considers fabric filters a technically feasible control technology for EUs 105, 107, 109, 110, 114, and 128 through 130. The ash unloading to disposal trucks (EU 111) occurs in a building with large doors. During ash unloading the doors remain closed to prevent the release of fugitive emissions.

Therefore, the Department does not consider a fabric filter a technically feasible control technology for EU 111.

(b) Scrubbers
The theory behind scrubbers was discussed in detail in the PM-2.5 BACT for the large dual fuel-fired boiler and will not be repeated here. The Department considers scrubbers a feasible control technology for the material handling units, except for EU 111. EU 111 does not have collected emissions and therefore a scrubber is not considered a technically feasible control technology.

(c) Suppressants
The use of dust suppression to control particulate matter can be effective for stockpiles and transfer points exposed to the open air. Applying water or a chemical suppressant can bind the materials together into larger particles which reduces the ability to become entrained in the air either from wind or material handling activities. The Department considers the use of suppressants a technically feasible control technology for all of the material handling units.

(d) Enclosures
An enclosure prevents the release of fugitive emissions into the ambient air by confining all fugitive emissions within a structure and preventing additional fugitive emissions from being generated from winds eroding stockpiles and lifting particulate matter from conveyors. Often enclosures are paired with fabric filters. The RBLC does not identify a control efficiency for an enclosure that is not associated with another control option. The Department considers enclosures a technically feasible control technology for the material handling units.

(e) Wind Screens
A wind screen is similar to a solid fence which is used to lower wind velocities near stockpiles and material handling sites. As wind speeds increase, so do the fugitive emissions from the stockpiles, conveyors, and transfer points. The use of wind screens is appropriate for materials not already located in enclosures. Due to all of the material handling units being operated in enclosures the Department does not consider wind screens a technically feasible control option for the material handling units.

(f) Vents/Closed System Vents/Negative Pressure Vents
Vents can control fugitive emissions by collecting fugitive emissions from enclosed loading, unloading, and transfer points and then venting emissions to the atmosphere or back into other equipment such as a storage silo. Other vent control designs include enclosing emission units and operating under a negative pressure. The Department considers vents to be a technically feasible control technology for the material handling units, except for EU 111. EU 111 does not have collected emissions and the vent system would be ineffective when trucks enter and departed the loading area.

Step 2 - Eliminate Technically Infeasible PM-2.5 Controls for the Material Handling Units
As explained in Step 1 of Section 4.7, the Department does not consider fabric filters, scrubbers, and vents as technically feasible PM-2.5 control technologies for EU 111. The Department does not consider wind screens as technically feasible PM-2.5 control technologies for the material handling units.

Step 3 - Rank the Remaining PM-2.5 Control Technologies for the Material Handling Units
The following control technologies have been identified and ranked for control of particulates from the material handling equipment:

(a)	Fabric Filters	(50 - 99% Control)
(d)	Enclosures	(50 - 99% Control)
(b)	Scrubber	(50% - 99% Control)
(e)	Cyclone	(20% - 70% Control)
(c)	Suppressants	(less than 90% Control)
(f)	Vents	(less than 90% Control)

Step 4 - Evaluate the Most Effective Controls

UAF BACT Proposal

UAF proposes the following as BACT for PM-2.5 emissions from the material handling units:

(a) PM-2.5 emissions from EUs 105, 107, 109 through 111, 114, and 128 through 130 will be controlled by enclosing each EU.

(b) PM-2.5 emissions from the operation of the material handling units, except EU 111, will be controlled by installing, operating, and maintaining fabric filters and vents.

(c) PM-2.5 emissions from EUs 105, 107, 109, 110, and 128 through 130 shall not exceed 0.003 gr/dscf.

(d) PM-2.5 emissions from EU 111 shall not exceed $5.5x10^{-5}$ lb/ton.

(e) PM-2.5 emissions from EU 114 shall not exceed 0.05 gr/dscf.

Step 5 - Selection of PM-2.5 BACT for the Material Handling Units
The Department's finding is that BACT for PM-2.5 emissions from the material handling equipment is as follows:

(a) PM-2.5 emissions from EUs 105, 107, 109 through 111, 114, and 128 through 130 will be controlled by enclosing each EU;

(b) PM-2.5 emissions from the operation of the material handling units, except EU 111, will be controlled by installing, operating, and maintaining fabric filters and vents;

(c) PM-2.5 emissions from EUs 105, 107, 109, 110, and 128 through 130 shall not exceed 0.003 gr/dscf;

(d) PM-2.5 emissions from EU 111 shall not exceed $5.5x10^{-5}$ lb/ton;

(e) PM-2.5 emissions from EU 114 shall not exceed 0.05 gr/dscf; and

(f) Initial compliance with the emission rates for the material handling units, except EU 111, will be demonstrated with a performance test to obtain an emission rate.

Table 4-20. PM-2.5 BACT Control Technologies Proposed for the Material Handling Units

Facility	Process Description	Capacity	Limitation	Control Method
UAF	7 Material Handling Units	Varies	0.003 gr/dcf	Fabric Filter & Enclosure & Vent
UAF	Ash Loadout to Truck (EU 111)	N/A	5.50E-05 lb/ton	Enclosure
UAF	Dry Sorbent Handing Vent Filter Exhaust	5 acfm	0.050 gr/dcf	Fabric Filter & Enclosure & Vent

5. BACT DETERMINATION FOR SO_2

The Department based its SO_2 assessment on BACT determinations found in the RBLC, internet research, and BACT analyses submitted to the Department by GVEA for the North Pole Power Plant and Zehnder Facility, Aurora for the Chena Power Plant, US Army for Fort Wainwright, and UAF for the Combined Heat and Power Plant.

5.1 SO_2 BACT for the Large Dual Fuel-Fired Boiler (EU 113)

Possible SO_2 emission control technologies for the large dual fuel-fired boiler were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 11.110, Coal Combustion in Industrial Size Boilers and Furnaces. The search results are summarized in Table 5-1.

Table 5-1: RBLC Summary of SO_2 Control for Industrial Coal-Fired Boilers

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Flue Gas Desulfurization / Scrubber / Spray Dryer	10	0.06 – 0.12
Limestone Injection	10	0.055 – 0.114
Low Sulfur Coal	4	0.06 – 1.2

RBLC Review

A review of similar units in the RBLC indicates flue gas desulfurization and low sulfur coal are the principle SO_2 control technologies installed on large dual fuel-fired boilers. The lowest SO_2 emission rate in the RBLC is 0.055 lb/MMBtu

Step 1 - Identification of SO_2 Control Technology for the Large Dual Fuel-Fired Boiler

From research, the Department identified the following technologies as available for control of SO_2 emissions from the large dual fuel-fired boiler:

(a) Flue Gas Desulfurization (FGD)/Scrubber/Spray Dryer
Two basic types of FGD systems exist, dry and wet scrubbing. In the wet scrubbing system, flue gas is contacted with a solution or slurry of alkaline material in a vessel providing a relatively long residence time. Generally, particulate matter has not been removed prior to entering into the adsorber, and the spray drying process acts as a combined SO_2/PM removal system. The SO_2 in the flue reacts with the alkali solution or slurry by adsorption and/or absorption mechanisms to form liquid-phase salts. These salts are dried to about one percent free moisture by the heat in the flue gas. These solids are entrained in the flue gas and carried from the dryer to a PM collection device, such as a baghouse.

Spray drying technology is less complex mechanically, and no more complex chemically, than wet scrubbing systems. The main advantages of the spray dryer is that this technology avoids two problems associated with wet scrubbing, corrosion and liquid waste treatment. A PM collection device is also required for dry scrubbing.

The vendor for the large dual fuel-fired boiler, Babcock & Wilcox, indicated that this new boiler design can accommodate a wet or dry FGD system. The wet FGD system is a spray dry adsorber (SDA) that would be located at grade between the air heater and the baghouse. The current baghouse and filter media is capable of handling the higher solids loading from an SDA. The system would utilize a baghouse fly ash recycle system which would activate a portion of the un-reacted lime in the fly ash. The recycled slurry, when sprayed through the atomizer, will reduce the SO_2 emissions, possibly without the need for any additional reagent depending on the level of SO_2 reduction required. The proposed SDA technology is expected to achieve an SO_2 emission rate of 0.04 lb/MMBtu, which is approximately 92 percent SO_2 control. The Department considers SDA a technically feasible control technology for the large dual fuel-fired boiler.

Babcock & Wilcox indicated that the large dual fuel-fired boiler design should include a small dry sorbent injection (DSI) system to reduce hydrofluoric acid (HF) and hydrochloric acid (HCl) emissions. This small DSI system is not designed for and is not expected to control SO_2 emissions. An add-on DSI system would be required for SO_2 control.

An add-on DSI system is possible and would use sodium bicarbonate or specialized hydrated lime as a reagent to react with SO_2. This form of a dry FDG system would likely require a silo for reagent storage, a mill building, pneumatic conveying, and reagent distribution upstream of the baghouse. Potentially, the baghouse ash handling system capacity would also need to be increased, depending on the sorbent injection rate. The add-on DSI system could achieve approximately a 75 percent SO_2 control. The Department considers an add-on DSI system for SO_2 emissions control to be a feasible control technology for the large dual fuel-fired boiler.

(b) Limestone Injection
In the limestone injection process, crushed coal and limestone are suspended in a boiler by an upward stream of hot air. The coal is burned in this bubbling fluidized mixture. The temperature in the combustion chamber of between 1,500 and 1,600 degrees is the correct temperature for the limestone to react with SO_2 to form a solid compound that is collected in a particulate matter collection device. The sulfur reduction can be achieved with either limestone or hydrated lime. Limestone injection technology has the benefits of low capital costs, low feed rates, and low operating costs.

The CFB design of the large dual fuel-fired boiler is capable of using limestone as part of the feed bed which controls the sulfur emissions released during coal combustion. The proposed fabric filter baghouse system would remove the particulate matter formed as calcium sulfate. The Department considers limestone injection a technically feasible control technology for the large dual fuel-fired boiler.

(c) Low Sulfur Coal
UAF purchases coal from the Usibelli Coal Mine located in Healy, Alaska. This coal mine is located 115 miles south of Fairbanks. The coal mined at Usibelli is sub-bituminous coal and has a relatively low sulfur content with guarantees of less than 0.4 percent by weight. Usibelli Coal Data Sheets indicate a range of 0.08 to 0.28 percent Gross As Received (GAR) percent Sulfur (%S). According to the U.S. Geological Survey, coal with less than one percent sulfur is classified as low sulfur coal. The Department considers the use of low sulfur coal a technically feasible control technology for the large dual fuel-fired boiler.

(d) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the large dual fuel-fired boiler and will not be repeated here. Proper management of the combustion process will result in a reduction of SO_2 emissions. The Department considers GCPs a technically feasible control technology for the large dual fuel-fired boiler.

Step 2 - Eliminate Technically Infeasible SO_2 Controls for the Large Dual Fuel-Fired Boiler
All identified control technologies are technically feasible for the large dual fuel-fired boiler.

Step 3 - Rank the Remaining SO_2 Control Technologies for the Large Dual Fuel-Fired Boiler
The following control technologies have been identified and ranked by efficiency for control of SO_2 emissions from the large dual fuel-fired boiler:

(a-1)	Wet Scrubber	(99% Control)
(a-2)	Spray Dry Absorbers	(92% Control)
(a-3)	Dry Sorbent Injection	(75% Control)
(d)	Good Combustion Practices	(Less than 40% Control)
(b)	Limestone Injection	(0% Control)
(c)	Low Sulfur Coal	(0% Control)

Control technologies already in practice at the stationary source or included in the design of the EU are considered 0% control for the purpose of the SIP BACT for existing stationary sources.

Step 4 - Evaluate the Most Effective Controls

UAF BACT Proposal

UAF provided an economic analysis of the installation of wet and dry scrubber systems. A summary of the analysis is shown below:

Table 5-2. UAF Economic Analysis for Technically Feasible SO_2 Controls

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Spray Dry Absorber	258.9	238.2	$15,600,000	$3,270,753	$13,732
Dry Sorbent Injection	258.9	194.2	$2,535,000	$1,697,487	$8,742
Capital Recovery Factor = 0.1424 (7% interest rate for a 10 year equipment life)					

UAF contends that the economic analysis indicates the level of SO_2 reduction does not justify the use of spray dry absorbers or dry-sorbent injection for the dual fuel-fired boiler based on the excessive cost per ton of SO_2 removed per year.

UAF proposes the following as BACT for SO_2 emissions from the dual fuel-fired boiler:

(a) SO_2 emissions from the operation of EU 113 will be controlled by the operation of limestone injection at all times the unit is in operation;

(b) SO_2 emissions from EU 113 will be controlled by burning low sulfur coal at all times the dual fuel-fired boiler is combusting coal; and

(c) SO_2 emissions from EU 113 will not exceed 0.2 lb/MMBtu.

Department Evaluation of BACT for SO_2 Emissions from the Dual Fuel-Fired Boiler

The Department revised the cost analyses provided for the installation of spray dry absorbers and dry sorbent injection and created a new cost analysis for wet scrubbers, all using the unrestricted potential to emit for the dual fuel-fired boiler, a baseline emission rate of 0.2 lb SO_2/MMBtu,[21] a retrofit factor of 1.0 for a retrofit of average difficulty, a SO_2 removal efficiency of 99%, 90%, and 80% for spray dry absorbers and dry sorbent injection respectively, and a 15 year equipment life. A summary of the analysis is shown below:

Table 5-3. Department Economic Analysis for Technically Feasible SO_2 Controls

Control Alternative	Potential to Emit (PTE)	Emission Reduction (tpy)	Total Capital Cost ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Wet Scrubber	259	257	$29,487,290	$6,081,181	$23,690
SDA	259	233	$27,132,570	$5,463,391	$23,411
DSI	259	207	$5,192,915	$1,731,023	$8,345
Capital Recovery Factor = 0.0996 (5.5% interest rate for a 15 year equipment life)					

The Department's economic analysis indicates the level of SO_2 reduction justifies the use of dry sorbent injection as BACT for the dual fuel-fired boiler located in the Serious PM-2.5 nonattainment area.

Step 5 - Selection of SO_2 BACT for the Large Dual Fuel-Fired Boiler

The Department's finding is that BACT for SO_2 emissions from the dual fuel-fired boilers is as follows:

(a) SO_2 emissions from EU 113 shall be controlled by operating and maintaining dry sorbent injection and limestone injection at all times the unit is in operation;

(b) EU 113 shall not exceed a SO_2 emission rate of 0.10 lb/MMBtu[22] averaged over a 3-hour period;

[21] Emission rate is SO_2 limit from 40 C.F.R. 60.42b(k)(1) [NSPS Subpart Db]

[22] BACT limit selected after evaluating existing emission limits in the RBLC database for coal-fired boilers, taking into account previous source test data from coal-fired boilers in Alaska and actual emissions data from other sources

(c) SO_2 emissions from EU 113 will be controlled by burning low sulfur coal at all times the dual fuel-fired boiler is combusting coal;

(d) Maintain good combustion practices at all times of operation by following the manufacturer's operating and maintenance procedures; and

(e) Initial compliance with the proposed SO_2 emission rate for the dual fuel-fired boilers will be demonstrated by conducting a performance test to obtain an emission rate.

Table 5-4 lists the proposed SO_2 BACT determination for this facility along with those for other coal-fired boilers in the Serious PM-2.5 nonattainment area.

Table 5-4. Comparison of SO_2 BACT for Coal-Fired Boilers at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
UAF	Dual Fuel-Fired Boiler	295.6 MMBtu/hr	0.10 lb/MMBtu[22]	Dry Sorbent Injection Limestone Injection Low Sulfur Coal
Fort Wainwright	Six Coal-Fired Boilers	1,380 MMBtu/hr (combined)	0.10 lb/MMBtu	Low Sulfur Coal Dry Sorbent Injection Operational Limit
Chena	Four Coal-Fired Boilers	497 MMBtu/hr (combined)	0.10 lb/MMBtu	Dry Sorbent Injection Low Sulfur Coal

5.2 SO_2 BACT for the Mid-Sized Diesel-Fired Boilers (EUs 3 and 4)

Possible SO_2 emission control technologies for mid-sized diesel-fired boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 12.220, Industrial Size Distillate Fuel Oil Boilers (>100 MMBtu/hr and ≤ 250 MMBtu/hr). The search results for mid-sized diesel-fired boilers are summarized in Table 5-5.

Table 5-5. RBLC Summary of SO_2 Control for Mid-Sized Boilers Firing Diesel

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
No Control Specified	2	0.0006

Possible SO_2 emission control technologies for mid-sized diesel-fired boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 12.310, Industrial Size Gaseous Fuel Boilers (>100 MMBtu/hr and ≤ 250 MMBtu/hr). The search results for mid-sized diesel-fired boilers are summarized in Table 5-6.

Table 5-6. RBLC Summary of SO_2 Control for Mid-Sized Boilers Firing Natural Gas

employing similar types of controls, using manufacturer data provided by Babcock & Wilcox, and in-line with EPA's pollution control Fact Sheets while keeping in mind that BACT limits must be achievable at all times.

Control Technology	Number of Determinations	Emission Limits
Low Sulfur Fuel	2	0.89 - 11.24 (tpy)
Good Combustion Practices	5	0.03 – 0.18 (lb/hr)
No Control Specified	4	0.01 – 0.09 (lb/hr)

RBLC Review
A review of similar units in the RBLC indicates low sulfur fuel and good combustion practices are the principle SO_2 control technologies installed on mid-sized boilers. The lowest SO_2 emission rate listed in the RBLC is 0.0006 lb/MMBtu.

Step 1 - Identification of SO_2 Control Technology for the Mid-Sized Diesel-Fired Boilers
From research, the Department identified the following technologies as available for SO_2 control for the mid-sized diesel-fired boilers:

(a) Ultra Low Sulfur Diesel
ULSD has a fuel sulfur content of 0.0015 percent sulfur by weight or less. Using ULSD would reduce SO_2 emissions because the mid-sized diesel-fired boilers are combusting standard diesel that has a sulfur content of up to 0.5 percent sulfur by weight. Switching to ULSD could reach a great than 99 percent decrease in SO_2 emissions from the mid-sized diesel-fired boilers. The Department considers ULSD a technically feasible control technology for the mid-sized diesel-fired boilers.

(b) Natural Gas
The theory of operating the mid-sized diesel-fired boilers on natural gas was discussed in detail in the NOx BACT for the mid-sized diesel-fired boilers and will not be repeated here. The Department does not consider operating the mid-sized diesel-fired boilers on natural gas as a technically feasible control technology.

(c) Limited Operation
The theory of limited operation for the mid-sized diesel-fired boilers was discussed in detail in the NOx BACT for the mid-sized diesel-fired boilers and will not be repeated here. The Department considers limited operation a technically feasible control technology for the mid-sized diesel-fired boilers.

(d) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the large dual fuel-fired boiler and will not be repeated here. Proper management of the combustion process will result in a reduction of SO_2 emissions. The Department considers GCPs a technically feasible control technology for the mid-sized diesel-fired boilers.

Step 2 - Eliminate Technically Infeasible SO_2 Control Technologies for the Mid-Sized Diesel-Fired Boilers
Limited operation for EU 3 is a technically infeasible control technology as it is a backup unit.

Step 3 - Rank the Remaining SO_2 Control Technologies for the Mid-Sized Diesel-Fired Boilers
The following control technologies have been identified and ranked by efficiency for the control of SO_2 emissions from themed-sized diesel-fired boilers.

(a) Ultra Low Sulfur Diesel (99% Control)
(d) Good Combustion Practices (Less than 40% Control)
(c) Limited Operation (0% Control)

Control technologies already in practice at the stationary source or included in the design of the EU are considered 0% control for the purpose of the SIP BACT for existing stationary sources.

Step 4 - Evaluate the Most Effective Controls

UAF BACT Proposal

UAF proposes the following as BACT for SO_2 emissions from the mid-sized diesel-fired boilers:

(a) SO_2 emissions from EUs 3 and 4 shall combust ULSD while firing diesel fuel;

(b) SO_2 emissions from EU 4 shall not exceed 0.60 lb/MMscf while firing natural gas; and

(c) SO_2 emissions from EU 4 will be limited by complying with the combined annual NOx emission limit of 40 tons per 12 month rolling period for EUs 4 and 8.

Step 5 - Selection of SO_2 BACT for the Mid-Sized Diesel-Fired Boilers

The Department's finding is that BACT for SO_2 emissions from the mid-sized diesel-fired boilers is as follows:

(a) SO_2 emissions from EUs 3 and 4 shall be controlled by only combusting ULSD when firing diesel fuel;

(b) SO_2 emissions from EU 4 will be limited by complying with the combined annual NOx emission limit of 40 tons per 12 month rolling period for EUs 4 and 8;

(c) SO_2 emissions from EU 4 while firing natural gas shall not exceed 0.60 lb/MMscf;

(d) Maintain good combustion practices by following the manufacturer's maintenance procedures at all times of operation; and

(e) Compliance with the proposed SO_2 emission limit will be demonstrated through fuel shipment receipts and/or fuel testing for sulfur content.

Table 5-7 lists the proposed BACT determination for this facility along with those for other mid-sized diesel-fired boilers located in the Serious PM-2.5 nonattainment area.

Table 5-7. Comparison of SO_2 BACT for the Mid-Sized Diesel-Fired Boilers at Nearby Power Plants

Facility	EU ID	Process Description	Capacity	Fuel	Limitation	Control Method
UAF	3	Dual Fuel-Fired Boilers	100 – 250 MMBtu/hr	Diesel	15 ppmw S in fuel	Ultra Low Sulfur Diesel
	4			Diesel	15 ppmw S in fuel	Limited Operation Ultra Low Sulfur Diesel
				Natural Gas	0.60 lb/MMscf	

5.3 SO_2 BACT for the Small Diesel-Fired Boilers (EUs 19 through 21)

Possible SO_2 emission control technologies for small diesel-fired boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code

13.220, Commercial/Institutional Size Boilers (<100 MMBtu/hr). The search results for small diesel-fired boilers are summarized in Table 5-8.

Table 5-8. RBLC Summary of SO_2 Control for Small Diesel-Fired Boilers

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Low Sulfur Content	5	0.0036 – 0.0094
Good Combustion Practices	4	0.0005
No Control Specified	5	0.0005

RBLC Review
A review of similar units in the RBLC indicates that good combustion practices and combustion of low sulfur fuel are the principle SO_2 control technologies installed on small diesel-fired boilers. The lowest SO_2 emission rate listed in the RBLC is 0.0005 lb/MMBtu

Step 1 - Identification of SO_2 Control Technology for the Small Diesel-Fired Boilers
From research, the Department identified the following technologies as available for SO_2 control for the small diesel-fired boilers:

(a) ULSD
The theory of ULSD was discussed in detail in the SO_2 BACT for the mid-sized diesel-fired boilers and will not be repeated here. The Department considers ULSD a technically feasible control technology for the small diesel-fired boilers.

(b) Limited Operation
The theory behind limited operation was discussed in detail in the NOx BACT for the small diesel-fired boilers and will not be repeated here. The Department considers limited operation as a technically feasible control technology for the small diesel-fired boilers.

(c) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the large dual fuel-fired boiler and will not be repeated here. Proper management of the combustion process will result in a reduction of SO_2. The Department considers GCPs a technically feasible control technology for the small diesel-fired boilers.

Step 2 - Eliminate Technically Infeasible SO_2 Control Technologies for the Small Diesel-Fired Boilers
All identified control technologies are technically feasible for the diesel-fired boilers.

Step 3 - Rank the Remaining SO_2 Control Technologies for the Small Diesel-Fired Boilers
The following control technologies have been identified and ranked by efficiency for the control of SO_2 emissions from the small diesel-fired boilers:

(a) Ultra Low Sulfur Diesel (99% Control)
(c) Good Combustion Practices (Less than 40% Control)
(b) Limited Operation (0% Control)

Control technologies already in practice at the stationary source or included in the design of the EU are considered 0% control for the purpose of the SIP BACT for existing stationary sources.

Step 4 - Evaluate the Most Effective Controls

UAF BACT Proposal

UAF proposes the following as BACT for SO_2 emissions from the small diesel-fired boilers:

(a) SO_2 emissions from the operation of the small diesel-fired boilers will be controlled by limiting the combined operation to no more than 19,650 hours per 12-month rolling period;

(b) SO_2 emissions from the operation of the small diesel-fired boilers shall be controlled by using ULSD (0.0015 sulfur by weight) at all times of operation; and

(c) Compliance with the proposed SO_2 emission limit will be demonstrated through fuel shipment receipts and/or fuel testing for sulfur content.

Step 5 - Selection of SO_2 BACT for the Small Diesel-Fired Boilers

The Department's finding is that BACT for SO_2 emissions from the diesel-fired boilers is as follows:

(a) SO_2 emissions from EUs 19-21 shall be controlled by limited the combined operation to no more than 19,650 hours per 12-month rolling period;

(b) SO_2 emissions from the diesel-fired boilers shall be controlled by only combusting ULSD; and

(c) Compliance will be demonstrated with fuel shipment receipts and/or fuel tests for sulfur content.

Table 5-9 lists the proposed SO_2 BACT determination for this facility along with those for other small diesel-fired boilers rated at less than 100 MMBtu/hr in the Serious PM-2.5 nonattainment area.

Table 5-9. Comparison of SO_2 BACT for the Small Diesel-Fired Boilers at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
Fort Wainwright	Diesel-Fired Boilers	< 100 MMBtu/hr	15 ppmw S in fuel	Limited Operation Good Combustion Practices Ultra-Low Sulfur Diesel
	Waste Fuel-Fired Boilers		0.5 % S by weight	Good Combustion Practices
UAF	3 Diesel-Fired Boilers	< 100 MMBtu/hr	15 ppmw S in fuel	Limited Operation Ultra-Low Sulfur Diesel
GVEA Zehnder	2 Diesel-Fired Boilers	< 100 MMBtu/hr	15 ppmw S in fuel	Good Combustion Practices Ultra-Low Sulfur Diesel

5.4 SO_2 BACT for the Large Diesel-Fired Engine (EU 8)

Possible SO_2 emission control technologies for large engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 17.100 - 17.190, Large Internal Combustion Engines (>500 hp). The search results for large diesel-fired engines are summarized in Table 5-10.

Table 5-10. RBLC Summary Results for SO_2 Control for Large Diesel-Fired Engines

Control Technology	Number of Determinations	Emission Limits (g/hp-hr)
Low Sulfur Diesel	27	0.005 – 0.02
Federal Emission Standards	6	0.001 – 0.005
Limited Operation	6	0.005 – 0.006
Good Combustion Practices	3	None Specified
No Control Specified	11	0.005 – 0.008

RBLC Review
A review of similar units in the RBLC indicates combustion of low sulfur fuel, limited operation, and good combustion practices are the principle SO_2 control technologies installed on large diesel-fired engines. The lowest emission rate listed in the RBLC is 0.001 g/hp-hr.

Step 1 - Identification of SO_2 Control Technology for the Large Diesel-Fired Engine
From research, the Department identified the following technologies as available for the control of SO_2 emissions from the large diesel-fired engine:

(a) Ultra Low Sulfur Diesel
The theory of ULSD was discussed in detail in the SO_2 BACT for the mid-sized diesel-fired boilers and will not be repeated here. The Department considers ULSD a technically feasible control technology for the large diesel-fired engine.

(b) Federal Standards
The theory of federal emission standards was discussed in detail in the NOx BACT for the large diesel-fired engine and will not be repeated here. The Department does not consider federal emission standards a technically feasible control technology for the large diesel-fired engine.

(c) Limited Operation
The theory of limited operation for EU 8 was discussed in detail in the NOx BACT for the large diesel-fired engine and will not be repeated here. The Department considers limited operation as a technically feasible control technology for the large diesel-fired engine.

(d) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the dual fuel-fired boiler and will not be repeated here. Proper management of the combustion process will result in a reduction of SO_2 emissions. The Department considers GCPs a technically feasible control technology for the large diesel-fired engine.

Step 2 - Eliminate Technically Infeasible SO_2 Control Technologies for the Large Diesel-Fired Engine
As explained in Step 1 of Section 5.4, the Department does not consider federal emission standards as a technically feasible control technology to control SO_2 emissions from the large diesel-fired engine.

Step 3 - Rank the Remaining SO_2 Control Technologies for the Large Diesel-Fired Engine

(a) Ultra Low Sulfur Diesel (99% Control)

(d) Good Combustion Practices (Less than 40% Control)
(c) Limited Operation (0% Control)

Control technologies already in practice at the stationary source or included in the design of the EU are considered 0% control for the purpose of the SIP BACT for existing stationary sources.

Step 4 - Evaluate the Most Effective Controls

UAF BACT Proposal

UAF proposes the following as BACT for SO_2 emissions from the large diesel-fired engine:

(a) SO_2 emissions from EU 8 shall be controlled by combusting ULSD (0.0015 weight percent sulfur); and

(b) SO_2 emissions from EU 8 will be limited by complying with the combined annual NOx emission limit of 40 tons per 12 month rolling period for EUs 4 and 8.

Step 5 - Selection of SO_2 BACT for the Large Diesel Fired-Engine

The Department's finding is that BACT for SO_2 emissions from the large diesel-fired engines is as follows:

(a) SO_2 emissions from EU 8 shall be controlled by combusting only ULSD (0.0015 weight percent sulfur);

(b) Limit the combined operation of EU 4 and 8 to no more than 40 tons of NOx per 12 month rolling average;

(c) Maintain good combustion practices by following the manufacturer's maintenance procedures at all times of operation; and

(d) Compliance will be demonstrated with fuel shipment receipts and/or fuel tests for sulfur content.

Table 5-11 lists the proposed BACT determination for this facility along with those for other diesel-fired engines rated at more than 500 hp located in the Serious PM-2.5 nonattainment area.

Table 5-11. Comparison of SO_2 BACT for Large Diesel-Fired Engines at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
Fort Wainwright	8 Large Diesel-Fired Engines	> 500 hp	15 ppmw S in fuel	Limited Operation Good Combustion Practices Ultra-Low Sulfur Diesel
UAF	Large Diesel-Fired Engine	13,266 hp	15 ppmw S in fuel	Limited Operation Good Combustion Practices Ultra-Low Sulfur Diesel
GVEA North Pole	Large Diesel-Fired Engine	600 hp	15 ppmw S in fuel	Good Combustion Practices Ultra-Low Sulfur Diesel
GVEA Zehnder	2 Large Diesel-Fired Engines	11,000 hp	500 ppmw S in fuel	Good Combustion Practices Ultra-Low Sulfur Diesel

5.5 SO_2 BACT for the Small Diesel-Fired Engines (EUs 23, 24, and 26 – 29)

Possible SO_2 emission control technologies for small engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 17.210, Small Internal Combustion Engines (<500 hp). The search results for small diesel-fired engines are summarized in Table 5-12.

Table 5-12. RBLC Summary of SO_2 Controls for Small Diesel-Fired Engines

Control Technology	Number of Determinations	Emission Limits (g/hp-hr)
Low Sulfur Diesel	6	0.005 – 0.02
No Control Specified	3	0.005

RBLC Review
A review of similar units in the RBLC indicates combustion of low sulfur fuel is the principle SO_2 control technology for small diesel-fired engines. The lowest SO_2 emission rate listed in the RBLC is 0.005 g/hp-hr.

Step 1 - Identification of SO_2 Control Technology for the Small Diesel-Fired Engines
From research, the Department identified the following technologies as available for control of SO_2 emissions from diesel-fired engines rated at less than 500 hp:

(a) Ultra Low Sulfur Diesel
The theory of ULSD was discussed in detail in the SO_2 BACT for the mid-sized diesel-fired boilers and will not be repeated here. The Department considers ULSD a technically feasible control technology for the small diesel-fired engines.

(b) Limited Operation
The theory of limited operation for EU 27 was discussed in detail in the NOx BACT for the small diesel-fired engine and will not be repeated here. The Department considers limited operation a technically feasible control technology for the small diesel-fired engines.

(c) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the large dual fuel-fired boiler and will not be repeated here. Proper management of the combustion process will result in a reduction of SO_2 emissions. The department considers GCPs a technically feasible control technology for the small diesel-fired engines.

Step 2 - Eliminate Technically Infeasible SO_2 Control Technologies for the Small Engines
All identified control technologies are technically feasible for the small diesel-fired engines.

Step 3 - Rank the Remaining SO_2 Control Technologies for the Small Diesel-Fired Engines
The following control technologies have been identified and ranked by efficiency for the control of SO_2 emissions from the small diesel-fired engines.

(a) Ultra Low Sulfur Diesel (99% Control)
(c) Good Combustion Practices (Less than 40% Control)
(c) Limited Operation (0% Control)

Control technologies already in practice at the stationary source or included in the design of the EU are considered 0% control for the purpose of the SIP BACT for existing stationary sources.

Step 4 - Evaluate the Most Effective Controls

UAF BACT Proposal

UAF proposes the following as BACT for SO_2 emissions from the small diesel-fired engine EU 27:

(a) SO_2 emissions from the operation of the small diesel-fired engine shall be controlled by using ULSD at all times of operation (0.0015 weight percent sulfur); and

(b) SO_2 emissions from the operation of the small diesel-fired engine will be controlled by limiting operation to no more than 4,380 hours per 12-month rolling period.

Department Evaluation of BACT for SO_2 Emissions from Small Diesel-Fired Engines

The Department reviewed UAF's proposal and found that in addition to combusting only ULSD, and limiting operation of the small diesel-fired engine, good combustion practices is BACT for SO_2.

Step 5 - Selection of SO_2 BACT for the Small Diesel-Fired Engines

The Department's finding is that BACT for SO_2 emissions from the small diesel-fired engines is as follows:

(a) SO_2 emissions from small diesel-fired engines shall be controlled by combusting only ULSD at all times of operation;

(b) SO_2 emissions from the operation of EU 27 will be controlled by limiting operation to no more than 4,380 hours per 12-month rolling period;

(c) Limit non-emergency operation of EUs 24, 28, and 29 to no more than 100 hours per year each for maintenance checks and readiness testing;

(d) Maintain good combustion practices by following the manufacturer's operational procedures at all times of operation;

(e) Compliance will be demonstrated with fuel shipment receipts and/or fuel tests for sulfur content; and

(f) Compliance with the operating hours limit will be demonstrated by monitoring and recording the number of hours operated on a monthly basis.

Table 5-13 lists the proposed BACT determination for this facility along with those for other diesel-fired engines rated at less than 500 hp located in the Serious PM-2.5 nonattainment area.

Table 5-13. Comparison of SO_2 BACT for Small Diesel-Fired Engines at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
Fort Wainwright	41 Small Diesel-Fired Engines	< 500 hp	15 ppmw S in fuel	Limited Operation Ultra-Low Sulfur Diesel Good Combustion Practices
UAF	Six Small Diesel-Fired Engine	< 500 hp	15 ppmw S in fuel	Limited Operation

Facility	Process Description	Capacity	Limitation	Control Method
				Federal Emission Standards Ultra-Low Sulfur Diesel

5.6 SO_2 BACT for the Pathogenic Waste Incinerator (EU 9A)

Possible SO_2 emission control technologies for pathogenic waste incinerators were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 21.300 for Hospital, Medical, and Infectious Waste Incinerators. The search results for pathogenic waste incinerators are summarized in Table 5-14.

Table 5-14. RBLC Summary of SO_2 Control for the Pathogenic Waste Incinerator

Control Technology	Number of Determinations	Emission Limits (lb/hr)
Natural Gas	1	0.0500

RBLC Review

A review of similar units in the RBLC indicates use of natural gas as fuel is the principle SO_2 control technology installed on pathogenic waste incinerators. The lowest emission rate listed in the RBLC is 0.0500 lb/hr.

Step 1 - Identification of SO_2 Control Technology for the Pathogenic Waste Incinerator

From research, the Department identified the following technologies as available for control of SO_2 emissions from pathogenic waste incinerators:

(a) Natural Gas
Natural gas combustion has a lower SO_2 emission rate than standard diesel combustion and can be a preferred fuel for this reason. The availability of natural gas in Fairbanks can be limited. The Department considers natural gas as a technically feasible control option for the pathogenic waste incinerator.

(b) Ultra Low Sulfur Diesel
The theory of ULSD was discussed in detail in the SO_2 BACT for the mid-sized diesel-fired boilers and will not be repeated here. The Department considers ULSD a technically feasible control technology for the pathogenic waste incinerator.

(c) Limited Operation
The theory behind the limited operation for EU 9A was discussed in detail in the NOx BACT for the pathogenic waste incinerator and will not be repeated here. The Department considers limited operation a technically feasible control technology for the pathogenic waste incinerator.

(d) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the large dual fuel-fired boiler and will not be repeated here. Proper management of the combustion process will result in a reduction of SO_2 emissions. The Department considers GCPs a technically feasible control technology for the pathogenic waste incinerator.

Step 2 - Eliminate Technically Infeasible SO_2 Control Technologies for the Pathogenic Waste Incinerator

Natural gas is eliminated as a technically infeasible SO_2 control technology for the pathogenic waste incinerator due to the limited availability.

Step 3 - Rank the Remaining SO_2 Control Technologies for the Pathogenic Waste Incinerator

The following control technologies have been identified and ranked by efficiency for the control of SO_2 emissions from the pathogenic waste incinerator:

(b) Ultra Low Sulfur Diesel (99% Control)
(c) Good Combustion Practices (Less than 40% Control)
(c) Limited Operation (0% Control)

Control technologies already in practice at the stationary source or included in the design of the EU are considered 0% control for the purpose of the SIP BACT for existing stationary sources.

Step 4 - Evaluate the Most Effective Controls

UAF BACT Proposal

UAF proposes the following as BACT for SO_2 emissions from the pathogenic waste incinerator:

(a) SO_2 emissions from the operation of EU 9A will be controlled by limiting operation to no more than 109 tons of waste combusted per 12-month rolling period;

(b) SO_2 emissions from the operation of EU 9A shall be controlled by combusting ULSD at all times of operation; and

(c) Compliance will be demonstrated with fuel shipment receipts and/or fuel tests for sulfur content.

Department Evaluation of BACT for SO_2 Emissions from the Pathogenic Waste Incinerator

The Department reviewed UAF's proposal and found that in addition to combusting only ULSD, and limiting operation, good combustion practices is BACT for control of SO_2 emissions from the pathogenic waste incinerator.

Step 5 - Selection of SO_2 BACT for the Pathogenic Waste Incinerator

The Department's finding is that BACT for SO_2 emissions from the pathogenic waste incinerator is as follows:

(a) SO_2 emissions from the operation of EU 9A will be controlled by limiting operation to no more than 109 tons of waste combusted per 12-month rolling period;

(b) SO_2 emissions from the operation of EU 9A shall be controlled by combusting ULSD at all times of operation;

(c) Maintain good combustion practices by following the manufacturer's operational procedures at all times of operation; and

(d) Compliance shall be demonstrated by obtaining fuel shipment receipts and/or fuel tests for sulfur content.

6. BACT DETERMINATION SUMMARY

Table 6-1. NOx BACT Limits

EU ID	Description	Capacity	Proposed BACT Limit	Proposed BACT Control
3	Mid-Sized Diesel-Fired Boiler	180.9 MMBtu/hr	0.02 lb/MMBtu	Selective Catalytic Reduction Good Combustion Practices
4	Mid-Sized Diesel-Fired Boiler	180.9 MMBtu/hr	Diesel: 0.2 lb/MMBtu NG: 140 lb/MMscf	Limited Operation (EUs 4 and 8 combined 40 tons per rolling 12 month period) Good Combustion Practices
8	Large Diesel-Fired Engine	13,226 hp	1.3 g/hp-hr	Selective Catalytic Reduction Turbocharger and Aftercooler Limit Operation for non-emergency use (100 hours per year) Limited Operation (EUs 4 and 8 combined 40 tons per rolling 12 month period) Good Combustion Practices
9A	Pathogenic Waste Incinerator	83 lb/hr	3.56 lb/ton	Limited Operation (109 tons per rolling 12 month period) Good Combustion Practices
19	Small Diesel-Fired Boiler	6.13 MMBtu/hr	0.015 lb/MMBtu	Limited Operation (19,650 hours per rolling 12 month period combined) Good Combustion Practices
20	Small Diesel-Fired Boiler	6.13 MMBtu/hr	0.015 lb/MMBtu	
21	Small Diesel-Fired Boiler	6.13 MMBtu/hr	0.015 lb/MMBtu	
23	Small Diesel-Fired Engine	235 kW	14.1 g/hp-hr	Good Combustion Practices
26	Small `Diesel-Fired Engine	45 kW	14.1 g/hp-hr	
27	Caterpillar C-15	500 hp	3.2 g/hp-hr	Turbocharger and Aftercooler Good Combustion Practices Limited Operation (4,380 hours per year)
24	Cummins	51 kW	14.1 g/hp-hr	Limit Operation for non-emergency use (100 hours each per year) Good Combustion Practices
28	Detroit Diesel	120 hp	14.1 g/hp-hr	
29	Cummins	314 hp	0.3 g/hp-hr	
113	Large Dual Fuel-Fired Boiler	295.6 MMBtu/hr	0.02 lb/MMBtu	Fabric Filters

Table 6-2. PM-2.5 BACT Limits

EU ID	Description	Capacity	Proposed BACT Limit	Proposed BACT Control
3	Mid-Sized Diesel-Fired Boiler	180.9 MMBtu/hr	0.012 lb/MMBtu	Good Combustion Practices
4	Mid-Sized Diesel-Fired Boiler	180.9 MMBtu/hr	Diesel: 0.012 lb/MMBtu NG: 0.0075 lb/MMBtu	Limited Operation (EUs 4 and 8 combined 40 tons per rolling 12 month period) Good Combustion Practices
8	Large Diesel-Fired Engine	13,226 hp	0.32 g/hp-hr	Positive Crankcase Ventilation Limited Operation (EUs 4 and 8 combined 40 tons per rolling 12 month period)
9A	Pathogenic Waste Incinerator	83 lb/hr	4.67 lb/ton	Multiple Chambers Limited Operation (109 tons per rolling 12 month period) Good Combustion Practices
19	Small Diesel-Fired Boiler	6.13 MMBtu/hr	7.06 g/MMBtu	Limited Operation (19,650 hours per rolling 12 month period combined) Good Combustion Practices
20	Small Diesel-Fired Boiler	6.13 MMBtu/hr	7.06 g/MMBtu	
21	Small Diesel-Fired Boiler	6.13 MMBtu/hr	7.06 g/MMBtu	
23	Small Diesel-Fired Engine	235 kW	1.0 g/hp-hr	Good Combustion Practices
26	Small `Diesel-Fired Engine	45 kW	1.0 g/hp-hr	
27	Caterpillar C-15	500 hp	0.11 g/hp-hr	Turbocharger and Aftercooler Good Combustion Practices Limited Operation (4,380 hours per year)
24	Cummins	51 kW	1.0 g/hp-hr	Limit Operation for non-emergency use (100 hours each per year) Good Combustion Practices
28	Detroit Diesel	120 hp	1.0 g/hp-hr	
29	Cummins	314 hp	0.015 g/hp-hr	
105	Material Handling Unit	1,600 acfm	0.003 gr/dscf	Fabric Filters Enclosures Vents
107	Material Handling Unit	1,600 acfm	0.003 gr/dscf	
109	Material Handling Unit	1,600 acfm	0.003 gr/dscf	
110	Material Handling Unit	2,000 acfm	0.003 gr/dscf	
111	Material Handling Unit	N/A	5.5×10^{-5} lb/ton	Enclosure
113	Large Dual Fuel-Fired Boiler	295.6 MMBtu/hr	0.006 lb/MMBtu	Fabric Filters
114	Material Handling Unit	5 acfm	0.05 gr/dscf	Fabric Filters Enclosures Vents
128	Material Handling Unit	1,650 acfm	0.003 gr/dscf	
129	Material Handling Unit	1,650 acfm	0.003 gr/dscf	
130	Material Handling Unit	1,650 acfm	0.003 gr/dscf	

Table 6-3. SO_2 BACT Limits

EU ID	Description	Capacity	Proposed BACT Limit	Proposed BACT Control
3	Mid-Sized Diesel-Fired Boiler	180.9 MMBtu/hr	15 ppmv S in Fuel	Ultra-Low Sulfur Diesel
4	Mid-Sized Diesel-Fired Boiler	180.9 MMBtu/hr	Diesel: 15 ppmv S in Fuel NG: 0.60 lb/MMscf	Ultra-Low Sulfur Diesel Limited Operation (EUs 4 and 8 combined 40 tons per rolling 12 month period)
8	Large Diesel-Fired Engine	13,226 hp	15 ppmv S in Fuel	Limited Operation (EUs 4 and 8 combined 40 tons per rolling 12 month period) Good Combustion Practices Ultra-Low Sulfur Diesel
9A	Pathogenic Waste Incinerator	83 lb/hr	15 ppmv S in Fuel	Ultra-Low Sulfur Diesel Limited Operation (109 tons per rolling 12 month period)
19	Small Diesel-Fired Boiler	6.13 MMBtu/hr	15 ppmv S in Fuel	Limited Operation (19,650 hours per rolling 12 month period combined) Ultra-Low Sulfur Diesel
20	Small Diesel-Fired Boiler	6.13 MMBtu/hr	15 ppmv S in Fuel	
21	Small Diesel-Fired Boiler	6.13 MMBtu/hr	15 ppmv S in Fuel	
23	Small Diesel-Fired Engine	235 kW	15 ppmv S in Fuel	Good Combustion Practices
26	Small `Diesel-Fired Engine	45 kW	15 ppmv S in Fuel	
27	Caterpillar C-15	500 hp	15 ppmv S in Fuel	Good Combustion Practices Limited Operation (4,380 hours per year)
24	Cummins	51 kW	15 ppmv S in Fuel	Limit Operation for non-emergency use (100 hours each per year) Good Combustion Practices
28	Detroit Diesel	120 hp	15 ppmv S in Fuel	
29	Cummins	314 hp	15 ppmv S in Fuel	
113	Large Dual Fuel-Fired Boiler	295.6 MMBtu/hr	0.10 lb/MMBtu	Dry Sorbent Injection Limestone Injection Low Sulfur Coal

THE STATE of ALASKA
GOVERNOR BILL WALKER

Department of Environmental Conservation

DIVISION OF AIR QUALITY
Director's Office

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CERTIFIED MAIL: 7017 1450 0002 0295 9684
Return Receipt Requested

October 20, 2017

Frances Isgrigg
Director of Environmental Health, Safety & Risk Management
University of Alaska Fairbanks
PO Box 758145
Fairbanks, AK 99775

Subject: Request for additional information for the Best Available Control Technology Technical Memorandum for University of Alaska Fairbanks by December 22, 2017

Dear Ms. Isgrigg:

A portion of the Fairbanks North Star Borough (FNSB) has been in nonattainment with the 24-hour National Ambient Air Quality Standard for fine particulate matter ($PM_{2.5}$) since 2009. In a letter dated April 24, 2015, I requested that the University of Alaska Fairbanks and other affected stationary sources voluntarily provide the Alaska Department of Environmental Conservation (ADEC) with a Best Available Control Technology (BACT) analysis in advance of the nonattainment area being reclassified to a Serious Area. On May 10, 2017, the US Environmental Protection Agency (EPA) published their determination that the FNSB $PM_{2.5}$ nonattainment area would be reclassified from a Moderate Area to a Serious Area effective June 9, 2017.[1]

Once the nonattainment area was reclassified to Serious, it triggered the need for Best Available Control Measure (BACM)/BACT analyses. A BACM analysis requires that ADEC review potential control measure options for the various sectors that contribute to the $PM_{2.5}$ air pollution in the nonattainment area. A BACT analysis must be conducted for applicable stationary sources such as the University of Alaska Fairbanks. BACM and BACT are required to be evaluated regardless of the level of contribution by the source to the problem or its impact on the areas ability to attain.[2] The BACT analysis is a required component of a Serious State Implementation Plan (SIP).[3] ADEC sent an email to Ms. Isgrigg on May 11, 2017 notifying her of the reclassification to Serious and included

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[1] Federal Register, Vol. 82, No. 89, Wednesday May 10, 2017 (https://dec.alaska.gov/air/anpms/comm/docs/2017-09391-CFR.pdf)

[2] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf, Clean Air Act 189 (b)(1)(B) and 189 (e) and CFR 51.1010(4)(i) require the implementation of BACT for point sources and precursors emissions and BACM for area sources.

[3] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf, Clean Air Act 189 (b)(1)(B) and 189 (e) require the implementation of BACT for point sources and precursors emissions and BACM for area sources

a request for the BACT analysis to be completed by August 8, 2017. The BACT analysis was submitted by email to ADEC on February 8, 2017 from University of Alaska Fairbanks. It included emission units found in Operating Permit AQ0316TVP02 Revision 1 and Minor Permit AQ0316MSS06 Revision 2.

ADEC reviewed the BACT analysis provided for the University of Alaska Fairbanks and is requesting additional information to assist it in making a legally and practicably enforceable BACT determination for the source. ADEC requests a response by December 22, 2017. If ADEC does not receive a response to this information request by this date, ADEC will make a preliminary BACT determination based upon the information originally provided. However, ADEC does not have the in depth knowledge of your facility's infrastructure and without additional information may select a more stringent BACT for your facility in order to be approvable by EPA. It is ADEC's intent to release the preliminary BACT determinations for public comment along with any precursor demonstrations and BACM analysis before the required public comment process for the Serious SIP. In order to provide this additional comment opportunity, ADEC must adhere to a strict schedule. Your assistance in providing the necessary information in a timely manner is greatly appreciated.

After ADEC makes a final BACT determination for the University of Alaska Fairbanks, it must include the determination in the Alaska's Serious SIP that then ultimately requires approval by EPA.[4] In addition, the BACT implementation 'clock' was also triggered by the EPA reclassification of the area to Serious on June 9, 2017. Therefore, the control measures that are included in the final BACT determination will be required to be fully implemented prior to June 9, 2021 - 4 years after reclassification.[5]

As indicated in a meeting on September 21, 2017 between ADEC Air Quality staff and the stationary sources affected by the BACT requirements, ADEC will also be using the information submitted or developed to support the BACT determinations for Most Stringent Measure (MSM) consideration. MSMs will be a required element of the state implementation plan if the State applies for an extension of the attainment date from EPA. Therefore, the information you submit will be used for both analyses.

ADEC appreciates the cooperation that we've received from the University of Alaska Fairbanks. ADEC staff would like to continue periodic meetings to keep track of timelines and progress. If you have any questions related to this request, please feel free to contact us. Deanna Huff (email: Deanna.huff@alaska.gov) and Cindy Heil (email: Cindy.heil@alaska.gov) are the primary contacts for this effort within the Division of Air Quality.

Sincerely,

Denise Koch

Denise Koch, Director
Division of Air Quality

[4] https://www.gpo.gov/fdsys/pkg/USCODE-2013-title42/html/USCODE-2013-title42-chap85-subchapI-partD-subpart4-sec7513a
[5] 40. CFR 51.1010(4)

Enclosures:

October 20, 2017	Request for Additional Information for UAF BACT Analysis
May 11, 2017	Serious SIP BACT due date email
April 24, 2015	Voluntary BACT Analysis for UAF

cc: Larry Hartig, ADEC/ Commissioner's Office
Alice Edwards, ADEC/ Commissioner's Office
Cindy Heil, ADEC/Air Quality
Deanna Huff, ADEC/ Air Quality
Jim Plosay, ADEC/ Air Quality
Aaron Simpson, ADEC/Air Quality
Brittany Crutchfield, ADEC/Air Quality
Frances Isgrigg/University of Alaska Fairbanks
Tim Hamlin, USEPA Region 10
Zach Hedgpeth, USEPA Region 10

ADEC Request for Additional Information
University of Alaska Fairbanks
BACT Technical Memorandum Review
SLR Report July 2016

October 20, 2017

Please address the following comments by providing the additional information identified by December 22, 2017. Following the receipt of the information the Alaska Department of Environmental Conservation (ADEC) intends to make its preliminary Best Available Control Technology (BACT) determination and release that determination for public comment. In order to provide this additional comment opportunity, ADEC must adhere to a strict schedule. Your assistance in providing the necessary information in a timely manner is greatly appreciated. Additional requests for information may result from comments received during the public comment period or based upon the new information provided in response to this information request.

This document does not represent a final BACT determination by ADEC. Please contact Aaron Simpson at aaron.simpson@alaska.gov with any questions regarding ADEC's comments.

Draft Comments

1. Equipment Life – Page 123 (Adobe page number) of the analysis[1] states "a standardized ten year return on investment at seven percent interest rate is assumed". This assumption for the equipment life is based solely on the statement that "because of the harsh climate, equipment in interior Alaska experiences more wear and tear than equipment in moderate climates". The 10 year equipment life assumption is based on the harsh climate and evidence must be provided to support the claim. This evidence could include information regarding the actual age of currently operating control equipment, or design documents for associated process equipment such as boilers. For references on equipment life see the Texas Region 6 SIP findings[2].

2. CFB Boiler: Wet Scrubbing – Clearly explain the basis for excluding wet scrubbing in the BACT analysis.

3. CFB Boiler: SDA and DSI
    a. As part of their Oklahoma Best Available Retrofit Technology (BART) Federal Implementation Plan (FIP) final rule for regional haze[3], US EPA Region 6 found that a reasonable estimate for equipment life is 30 years for SO_2 control technologies, please provide a detailed explanation for the equipment life listed for the SDA and DSI control technologies.
    b. Please provide the documents for the following citations:
        i. "SCI engineering estimates (5 years old) for other SDAs."
        ii. "SCI engineering estimates (5 years old) for other DSI systems"
        iii. "Internal SDA cost study done by SCI in 2010, which indicated 8%."

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[1] University of Alaska Fairbanks, Voluntary Best Available Control Technology Analysis for the Serious $PM_{2.5}$ Non-Attainment Area Classification, Prepared by SLR, January 2017

[2] https://www.regulations.gov/document?D=EPA-R06-OAR-2014-0754-0001

[3] 76 FR 81728, December 28, 2011

  iv. "…similar internal SCI SDA cost analysis and other vendor (FTEK SCR) quotes."
  v. "Internet research bulk price" for hydrated lime.
  vi. "Internet research bulk price" for sodium bicarbonate.
  vii. "Current Per kW price based on GVEA data."

4. CFB Boiler: SNCR
   a. Please provide the technical justification for the 10-20% emission reduction stated in the email from Babcok and Wilcox for NOx SNCR.
   b. Please provide documentation for the following citations in the BACT analysis:
      i. Indirect capital costs "18% was used in similar SCR BACT analysis. Assume same amount for SNCR."
      ii. "ammonia solution cost from similar BACT analysis - $0.75/gal and specific gravity of 0.9."
      iii. "Current Per kW price based on GVEA data."
   c. The budgetary nature of the costs provided by FuelTech (+/- 30%) is reflected in the nature of the cost effectiveness analysis methodology established in the EPA Cost Manual – provide justification for including a 30% contingency factor.

5. CFB Boiler: SCR – Please revise the cost analysis submitted using the EPA updated coast manual chapter pertaining to SCR[4]. Specific comments related to the SCR cost effectiveness analysis include the following:
   a. The recently updated cost manual chapter covering SCR includes information regarding SCR equipment life, and indicates the technology can be expected to last 30 years. Please document why the actual expected equipment life of the control equipment is different from this value.
   b. The BACT analysis as submitted states that the normal exhaust temperature from the CFB boiler is expected to be 1,550-1,650˚F, which is outside of the SCR listed acceptable temperature range. Please provide a technical explanation of why the boiler exhaust temperature is so high. The analysis must also include consideration of high temperature SCR.
   c. Documentation must be provided for the following cited information:
      i. "Cost of startup spares indicated as a percentage of equipment cost per similar project."
      ii. Fab Site Vendor "days based on similar project".
      iii. Onsite Vendor "days based on similar project".
      iv. Indirect capital costs "18% was used in similar SCR BACT analysis for smaller CTs."
      v. "ammonia solution cost from similar BACT analysis - $0.75/gal and specific gravity of 0.9."
      vi. "Current Per kW price based on GVEA data."
      vii. "Replacement labor based on similar project."
      viii. "Labor cost based on similar project."
   d. The budgetary nature of the costs provided by FuelTech (+/- 30%) is reflected in the nature of the cost effectiveness analysis methodology established in the EPA Cost Manual – Please include why a 30% contingency factor is accurate.

[4] https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution

6. EU 3 Mid-Sized Diesel Boiler: PTE – Detailed basis must be provided for the NO_X PTE of 138.8 tpy for EU 3 used in the calculations. If PTE is based on the baseline emission rate used in the FuelTech quote (0.175 lb/MMBtu), the BACT limit proposed for good combustion practices should be 0.175 lb/MMBtu as well.

7. EU 3 Mid-Sized Diesel Boiler: LNB/FGR – This technology is eliminated based on cost effectiveness calculated assuming actual emissions. Please revise the cost analyses to be based on PTE.

8. EU 3 Mid-Sized Diesel Boiler: SCR
   a. Please provide the documentation for following citations in the BACT analysis.
      i. "December 2015 price according to Farmer's Coop Association."
      ii. "Replacement labor based on similar project."
      iii. Transport cost direct to site (SCR catalyst). "Based on similar project."
      iv. Transport cost for spent SCR catalyst. "Based on similar project."
   b. No basis is provided for the SCR freight cost of $20,000.
   c. Initial performance testing cost is included twice.
   d. The budgetary nature of the costs provided by FuelTech (+/- 30%) is reflected in the nature of the cost effectiveness analysis methodology established in the EPA Cost Manual, provide justification for 30% contingency factor.

9. EU 8 Large Diesel Fired Engine: Operational Scenario – Revise the cost analysis to assume operational hours of the unit up to 40 tpy as the emission limit, currently the calculations assume 8760 hours/yr.

10. EU 8 Large Diesel Fired Engine: DPF and SCR – The BACT analysis identifies back pressure as a potential technical challenge of installing a DPF to a large diesel engine such as EU 8, please provide a technical analysis basis for this statement.

11. EU 27 ACEP Generator – The BACT analysis includes evaluations of SCR and DPF as applied individually for control of NO_X and $PM_{2.5}$ respectively, from this emission unit. In addition please evaluate combined SCR/DPF.

12. For the purposes of this BACT analysis the cost analysis for each emissions control for each of EUs 4 and 8 should be based on the assumption that the 40 tpy NOx limit will be consumed by the EU being evaluated. Under the current permitting limit it is possible for one of EUs 4 and 8 to be the sole contributor to the 40 tpy of NOx in any given 12 month rolling period. Additionally, the 10 percent capacity limit for EU 4 was removed with the issuance of Minor Permit No. AQ0316MSS04 on August 4, 2016, and is therefore no longer applicable as limited operation for EU 4. Please revise the PTE and cost analysis for these units.

13. Describe for each emission unit type, what constitutes good combustion practices. Include any work or operational practice that will be implemented and describe how continuous compliance with good combustion practices will be achieved.

THE STATE of ALASKA

GOVERNOR BILL WALKER

Department of Environmental Conservation

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Return Receipt Requested

April 24, 2015

Frances Isgrigg
Director of Environmental Health, Safety & Risk Management
University of Alaska Fairbanks
PO Box 758145
Fairbanks, AK 99775

Subject: Voluntary BACT Analysis for Fairbanks Campus Power Plant

Dear Ms. Isgrigg:

Portions of the Fairbanks North Star Borough are in nonattainment with the 24-hour National Ambient Air Quality Standard for Fine Particulate Matter (PM 2.5). The Alaska Department of Environmental Conservation (ADEC) expects that the Environmental Protection Agency (EPA) will change the nonattainment designation from a Moderate Area to a Serious Area in June 2016. Once EPA designates the area as Serious, an 18-month clock begins for submittal of an implementation plan that includes best available control technologies (BACT) analysis and determination for stationary sources with over 70 tons per year (TPY) potential to emit (PTE) for PM2.5 or its precursors.

ADEC has neither the funding nor the in depth knowledge of your facility's infrastructure to determine the most appropriate BACT for your facility. Without the information or resources necessary to conduct detailed cost analysis and produce supporting documentation, ADEC may select a more stringent BACT for your facility in order to be approvable by EPA. In addition, 18 months is likely not adequate to complete a thorough BACT analysis.

Therefore, ADEC requests that your facility voluntarily begin the BACT analysis. We request that you submit an initial BACT analysis to ADEC by December 2015 and the final BACT analysis by March 2016 to ADEC. ADEC is required to make a BACT determination for every eligible facility within the designated PM2.5 nonattainment area and final BACT determinations are ultimately reviewed by EPA and subject to federal approval as part of the federally required PM2.5 implementation plan.

Background

EPA required that ADEC submit a State Implementation Plan (SIP) because portions of the Fairbanks North Star Borough (FSNB) are in nonattainment with the health based 24-hour National Ambient Air Quality Standard for PM2.5. ADEC submitted an initial, Moderate Area PM2.5 SIP for FNSB to EPA on December 31, 2014.

Unfortunately, this Moderate Area SIP was developed as an impracticable SIP because modeling was unable to demonstrate that attainment with the health standard was possible by December 30, 2015. Preliminary air monitoring results also indicate that FNSB will not demonstrate attainment in 2015. Attainment is calculated on a rolling three year average of the highest 98th percentile concentration at each monitor. When those monitoring results become final in May 2016 and an official three year design value is calculated, the FNSB non-attainment area will remain over the 24-hr PM 2.5 standard of 35 $\mu g/m^3$. The final determination of this design value will result in the FNSB non-attainment area being reclassified from a Moderate Area to a Serious Area[1] (40 CRF Parts 50, 51 and 93). This reclassification will happen by operation of law as outlined in Clean Air Act Sections 188 and 189. It is anticipated that the formal designation to Serious Area will occur in June 2016.

A Serious Area designation will result in several new, more stringent requirements, one of which is that all source categories in the nonattainment area that meet the BACT threshold of 70 TPY PTE for $PM_{2.5}$ and its precursor pollutants (NOx, SO2, VOC, NH3) must be analyzed for Best Available Control Measures (BACM). As part of BACM, a Best Available Control Technologies (BACT) analysis will be required. The Serious Area BACT trigger requires the same approach as a PSD/NSR BACT project. A Serious non-attainment area BACT limit is set using a top-down analysis on a case-by-case basis taking into account energy, environmental and economic impacts, and costs. The analysis must include all emission units at the source.

The timelines for completion of the BACT analysis, subsequent BACT determination, and the submittal of the Serious Area SIP are outlined in the preamble of the Particulate Matter 10 (PM10) rule and reconfirmed in the newly proposed $PM_{2.5}$ Implementation Rule[2]. Both rules require a completed SIP 18 months after designation to Serious. This 18 month time period does not allow enough time to thoroughly evaluate BACT, update the emission inventory, complete the modeling and allow for development and processing for a Serious Area SIP.

ADEC believes that it is best for facilities to complete the BACT analysis for their own facilities. ADEC does not have the funding to develop the analysis nor the in depth knowledge of each sources' infrastructure. ADEC would therefore base the cost analysis on the installation of control equipment without being able to factor in all the costs associated with retrofitting existing equipment. Without the detailed cost analysis and supporting documentation to support less stringent BACT options, it is doubtful that the BACT portions of the Serious SIP will be approvable without using the most stringent measures.

By requesting an early BACT analysis for facilities before the official Serious Area designation, it will help ADEC meet the following timelines and ultimately submit a Serious Area SIP to EPA by the

[1] 40 CFR Parts 50,51 and 93 http://www.epa.gov/airquality/particlepollution/actions.html

[2] http://www.epa.gov/airquality/particlepollution/actions.html

required due date. Early analysis also has the potential to increase flexibility for each Stationary Source under the rules.

- Serious Area SIP inventory development starts: January, 2015
- BACT kick off meeting: March 5, 2015
- Submit initial BACT results to ADEC: December, 2015
- Submit complete/final BACT analysis to ADEC: March, 2016
- Serious Area SIP modeling by ADEC starts: March, 2016
- Serious Area designation by EPA (Expected): June, 2016
- Serious Area SIP draft: December, 2016
- Serious Area SIP public notice period: February, 2017
- Serious Area SIP submitted by ADEC to EPA: December, 2017

Meeting the BACT analysis requirements is a major component of a Serious SIP. This is a challenging issue. It is important that ADEC accurately reflect the contributions of industrial sources to the air pollution problem and the potential improvements available within this emission sector along with the other emission sources in the community.

ADEC staff would like to continue periodic meetings to keep track of timelines and progress. If you have any questions related to this request, please feel free to contact us. Deanna Huff (email: Deanna.huff@alaska.gov) and Cindy Heil (email: Cindy.heil@alaska.gov) are the primary contacts for this effort within the Division of Air Quality.

Sincerely,

Denise Koch

Denise Koch, Director
Division of Air Quality

cc: Larry Hartig, ADEC/ Commissioner's Office
Alice Edwards, ADEC/ Commissioner's Office
John Kuterbach, ADEC/ Air Quality
Cindy Heil, ADEC/Air Quality
Deanna Huff, ADEC/ Air Quality

University of Alaska Fairbanks – Serious PM-2.5 NA BACT Analysis
BACT Analysis Review Comments
Report dated January 2017 – SLR

Zach Hedgpeth, PE
EPA Region 10 – Seattle
November 2, 2017

1. Equipment Life – Page 123 of the analysis[1] states "a standardized ten year return on investment at seven percent interest rate is assumed". This assumption for the equipment life is based solely on the statement that "because of the harsh climate, equipment in interior Alaska experiences more wear and tear than equipment in moderate climates". The analysis includes no further information to support the assumption of a ten year equipment life, nor the underlying assertion regarding wear and tear. The analysis must use a reasonable estimate of the actual life of the control equipment for each control technology, based on the best evidence available. In order to use an equipment life that is shortened based on the harsh climate, evidence must be provided to support the claim. This evidence could include information regarding the actual age of currently operating control equipment, or design documents for associated process equipment such as boilers.
2. CFB Boiler: Additional SO_2 Control Technologies – The BACT analysis mentions wet scrubbing technologies, but does not clearly explain the basis for excluding these technologies (such as limestone slurry forced oxidation) from consideration within the analysis. Since wet scrubbing would be expected to represent the highest SO_2 removal efficiency, this technology must be fully evaluated within the BACT analysis. Similarly, the analysis does not evaluate dry flue gas desulfurization or dry scrubbing. This enhanced dry SO_2 control technology can achieve higher removal efficiencies than dry sorbent injection, and must also be evaluated thoroughly within the BACT analysis. The BACT analysis must include rigorous site-specific evaluation of the technical feasibility and cost effectiveness of these technologies.
3. CFB Boiler: SDA and DSI
    a. As part of their Oklahoma Best Available Retrofit Technology (BART) Federal Implementation Plan (FIP) final rule for regional haze[2], EPA Region 6 conducted significant research into the actual expected lifetime of SO_2 control technologies, including wet, semi-dry, and dry scrubbing. Region 6 found that 30 years is a reasonable estimate of actual expected equipment life for these control technologies. The analysis for SDA and DSI therefore should use 30 years unless documented evidence is provided establishing that the actual expected equipment life of the control equipment is different from this value.
    b. The SDA and DSI cost analyses submitted with this analysis cite the following documents as the basis for costs and other information relied upon in the analysis, however, these documents have not been provided. These documents must be provided in order to rely upon the cited information in the analysis:
        i. "SCI engineering estimates (5 years old) for other SDAs."
        ii. "SCI engineering estimates (5 years old) for other DSI systems"
        iii. "Internal SDA cost study done by SCI in 2010, which indicated 8%."
        iv. "…similar internal SCI SDA cost analysis and other vendor (FTEK SCR) quotes."
        v. "Internet research bulk price" for hydrated lime.

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[1] University of Alaska Fairbanks, Voluntary Best Available Control Technology Analysis for the Serious $PM_{2.5}$ Non-Attainment Area Classification, Prepared by SLR, January 2017
[2] 76 FR 81728, December 28, 2011

    vi. "Internet research bulk price" for sodium bicarbonate.
    vii. "Current Per kW price based on GVEA data."

4. CFB Boiler: SNCR
    a. Within an email included in Appendix B, Babcock & Wilcox states only minimal NO_X reduction of around 10-20% would be expected from SNCR. In order to base the cost analysis on this minimal emission reduction, detailed technical justification must be submitted providing a rigorous basis for why SNCR can only achieve this smaller than average/expected emission reduction for this emission unit.
    b. The SNCR cost analysis cites the following documents and information as the basis for costs and other information relied upon in the analysis, however, documentation for these values and information has not been provided. Documentation must be provided in order to rely upon the cited information in the analysis:
        i. Indirect capital costs "18% was used in similar SCR BACT analysis. Assume same amount for SNCR."
        ii. "ammonia solution cost from similar BACT analysis - $0.75/gal and specific gravity of 0.9."
        iii. "Current Per kW price based on GVEA data."
    c. The budgetary nature of the costs provided by FuelTech (+/- 30%) is reflected in the nature of the cost effectiveness analysis methodology established in the EPA Cost Manual – it is not appropriate to include a 30% contingency factor based on this accuracy range.
5. CFB Boiler: SCR – The EPA has recently updated the cost manual chapter pertaining to SCR, and developed a cost spreadsheet to be used for evaluation of this technology for cost effectiveness[3]. The cost analysis submitted as part of this BACT analysis[4] does not use the EPA cost spreadsheet. Specific comments related to the SCR cost effectiveness analysis include the following:
    a. The recently updated cost manual chapter covering SCR includes information regarding SCR equipment life, and indicates the technology can be expected to last 30 years. The analysis should use 30 years as the equipment life for SCR unless documented evidence is provided establishing that the actual expected equipment life of the control equipment is different from this value.
    b. The BACT analysis as submitted states that the normal exhaust temperature from the CFB boiler is expected to be 1,550-1,650˚F. This factor is listed as a technical feasibility issue for SCR as a potential control technology since the temperature range for SCR is listed as 500-800˚F. Please provide a technical explanation of why the boiler exhaust temperature is so high, and why additional heat recovery has not been included in the design of the new power plant. The analysis must also include thorough analysis of high temperature SCR with respect to technical feasibility and cost effectiveness.
    c. The SCR cost analysis cites the following documents and information as the basis for costs and other information relied upon in the analysis, however, documentation for these values and information has not been provided. Documentation must be provided in order to rely upon the cited information in the analysis:
        i. "Cost of startup spares indicated as a percentage of equipment cost per similar project."
        ii. Fab Site Vendor "days based on similar project".
        iii. Onsite Vendor "days based on similar project".

[3] https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution

[4] "UAF BACT NOx Tables 3-X.xlsx"

iv. Indirect capital costs “18% was used in similar SCR BACT analysis for smaller CTs.”
v. “ammonia solution cost from similar BACT analysis - $0.75/gal and specific gravity of 0.9.”
vi. “Current Per kW price based on GVEA data.”
vii. “Replacement labor based on similar project.”
viii. “Labor cost based on similar project.”

d. The budgetary nature of the costs provided by FuelTech (+/- 30%) is reflected in the nature of the cost effectiveness analysis methodology established in the EPA Cost Manual – it is not appropriate to include a 30% contingency factor based on this accuracy range.

6. <u>EU 3 Mid-Sized Diesel Boiler: PTE</u> – Detailed basis must be provided for the NO_X PTE of 138.8 tpy for EU 3 used in the calculations. Note that page 19 of the Title V statement of basis[5] states that emissions from this boiler “in terms of ton/yr were never and will not be limited”. Based on the proposed BACT limit of 0.2 lb/MMBtu for good combustion practices, it appears the PTE should, at a minimum, reflect full load operation at this emission rate for 8,760 hours/year (about 158 tpy). If PTE is based on the baseline emission rate used in the FuelTech quote (0.175 lb/MMBtu), the BACT limit proposed for good combustion practices should be 0.175 lb/MMBtu as well.
7. <u>EU 3 Mid-Sized Diesel Boiler: LNB/FGR</u>
   a. This technology is eliminated based on cost effectiveness calculated assuming actual emissions. All cost analyses and BACT determinations must be based on PTE.
   b. On page 39, the BACT analysis describes this control option as “installation of a new burner on the boiler that is already equipped with a LNB and FGR”. The analysis must clarify the current status of the boiler with respect to LNB and FGR technology. If the boiler is already equipped with FGR, detailed technical justification must be provided regarding why the fan(s) and/or ducting must be replaced.
8. <u>EU 3 Mid-Sized Diesel Boiler: SCR</u>
   a. The SCR cost analysis cites the following documents and information as the basis for costs and other information relied upon in the analysis, however, documentation for these values and information has not been provided. Documentation must be provided in order to rely upon the cited information in the analysis:
      i. “December 2015 price according to Farmer's Coop Association.”
      ii. “Replacement labor based on similar project.”
      iii. Transport cost direct to site (SCR catalyst). “Based on similar project.”
      iv. Transport cost for spent SCR catalyst. “Based on similar project.”
   b. No basis is provided for the SCR freight cost of $20,000.
   c. Initial performance testing cost is included twice.
   d. The budgetary nature of the costs provided by FuelTech (+/- 30%) is reflected in the nature of the cost effectiveness analysis methodology established in the EPA Cost Manual – it is not appropriate to include a 30% contingency factor based on this accuracy range.
9. <u>EU 3 Mid-Sized Diesel Boiler: ULSD</u> – The ULSD cost analysis is based on “review of UAF's fuel costs from FY 2011 through 2016. Average of the FY 2014 through 2016 is used, which is 28 cents per gallon more to use ULSD.” The documents forming the basis for this information must be submitted in order to rely on this information for purposes of the analysis.
10. <u>EU 8 Large Diesel Fired Engine: Operational Scenario</u> – The NO_X BACT analysis for this unit applies the facility-requested 40 ton per year emission limit, and bases the analysis on an

[5] ADEC Permit No. AQ0316TVP02, Significant Revision 1: June 22, 2012, Statement of Basis

assumed NO_X reduction of only 36 tons (90% reduction from 40 tpy). However, the analysis assumes that the unit operates 8,760 hours/year when calculating the annual O&M costs (i.e., see aqueous ammonia cost). The assumptions underlying the cost analysis are therefore inconsistent. The cost effectiveness analysis must be revised to be consistent based on the assumed operational scenario for the unit. For example, if the unit is assumed to operate uncontrolled for NO_X up to the 40 ton/year limit, the corresponding costs associated with only those limited number of hours may be included. This applies to all annual operating & maintenance costs, including catalyst life.

11. EU 8 Large Diesel Fired Engine: SCR – Please provide detailed information regarding the visible emissions described in the BACT analysis which were observed during operation of the SCR currently installed on the large diesel engine. See page 19.
12. EU 8 Large Diesel Fired Engine: DPF and SCR – The BACT analysis identifies back pressure as a potential technical challenge of installing a DPF to a large diesel engine such as EU 8, but provides no technical analysis or other quantitative or analytical basis for this argument. Further, the BACT analysis determines that an appropriate DPF "likely does not exist" without citing any information from established DPF equipment suppliers. The BACT analysis cites only a single local Fairbanks engine company, whose employee states that the company has "never supplied a DPF with a new engine or for after market use". The information provided forms insufficient basis to reject DPF as technically infeasible and/or not cost effective. The analysis must provide detailed technical analysis of the back pressure issue by an engineering firm or control equipment supplier with the necessary expertise regarding the control technology. In order to establish the availability of a suitable DPF, the analysis must include information regarding these topics from established DPF control equipment suppliers. The availability of this control technology is not limited to DPF equipment currently available "off the shelf". UAF must explore whether manufacture of an appropriate DPF for this emission unit is technically feasible, and conduct an emission unit specific cost analysis following the EPA Cost Manual.
13. EU 27 ACEP Generator – The BACT analysis includes evaluations of SCR and DPF as applied individually for control of NO_X and $PM_{2.5}$ respectively, from this emission unit, however a combination SCR/DPF was not evaluated. The analysis must be revised to include a cost effectiveness analysis for this combined control technology.

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December 21, 2017

Denise Koch, Director
Alaska Department of Environmental Conservation
Division of Air Quality
410 Willoughby Avenue, Suite 303
Juneau, Alaska 99811-1800

Subject: ADEC Request for additional information for the Best Available Control Technology for University of Alaska Fairbanks

Dear Ms. Koch:

The University of Alaska Fairbanks (UAF) received a request for additional information regarding the Best Available Control Technology (BACT) analysis from the Alaska Department of Environmental Conservation (ADEC) on October 20, 2017. This request included a set of 13 comments. ADEC provided a second set of comments and information requests from the US Environmental Protection Agency (EPA) Region 10 on November 6, 2017.

UAF understands that ADEC expects responses to both sets of comments. EPA Region 10 comments 1 through 8 are similar or identical to ADEC comments 1 through 8. EPA Region 10 comments 9 and 11 address issues that were not mentioned in the ADEC comments. Comment 10 from EPA Region 10 is a similar question to comment 9 from ADEC, and comments 12 and 13 from EPA Region 10 are comparable to ADEC comments 10 and 11. Comments 12 and 13 from ADEC were not addressed in the EPA Region 10 comments.

UAF is providing responses to each comment from EPA Region 10, and to ADEC comments 12 and 13, thus addressing each comment from both agencies. Each comment is repeated verbatim in the attachment, followed by the UAF response.

If you have any questions or require additional information regarding this response, please feel free to contact me using the information below my signature.

Sincerely,

Russ Steiger
Environmental Compliance Officer
University of Alaska Fairbanks
Office of Environmental, Health, Safety, and Risk Management
Office: (907) 474-5812
Mobile: (716) 534-1511
Email: rhsteiger@alaska.edu

Enclosures:

Attachment 1: UAF Response to EPA Region 10 and ADEC Comments on BACT Analysis

cc (email) Deanna Huff/ADEC
Cindy Heil/ADEC
Aaron Simpson/ADEC
Denise Koch/ADEC
Zach Hedgpeth/EPA Region 10
Frances Isgrigg/UAF EHSRM

ATTACHMENT 1
UAF RESPONSE TO EPA REGION 10 and ADEC COMMENTS ON BACT ANALYSIS

EPA Region 10 Comments

1. Equipment Life – Page 123 of the analysis states "a standardized ten year return on investment at seven percent interest rate is assumed". This assumption for the equipment life is based solely on the statement that "because of the harsh climate, equipment in interior Alaska experiences more wear and tear than equipment in moderate climates". The analysis includes no further information to support the assumption of a ten-year equipment life, nor the underlying assertion regarding wear and tear. The analysis must use a reasonable estimate of the actual life of the control equipment for each control technology, based on the best evidence available. In order to use an equipment life that is shortened based on the harsh climate, evidence must be provided to support the claim. This evidence could include information regarding the actual age of currently operating control equipment, or design documents for associated process equipment such as boilers.

UAF Response to Comment 1:
Consistent with established ADEC practice and previously approved PSD permitting BACT analyses, a 10-year equipment life was used in the calculation of the capital recovery factor for the UAF BACT analysis. This 10-year equipment life timeframe is appropriate for equipment operated in the harsh Alaska climate. Two recent permits with BACT analyses based on a 10-year life are Permit No. AQ0237CPT04 (see footnote to Table B-4 of the Technical Analysis Report) and Permit No. AQ0083CPT06 (see page 24 of Technical Analysis Report).

The EPA Air Pollution Control Cost Manual (sixth edition, EPA/452/B-02-001, Control Cost Manual) uses equipment lifetimes between 5 and 30 years. Ten, 15, and 20-year lifespans are frequently used in the manual.

The updated selective catalytic reduction (SCR) section of the Control Cost Manual states "broadly speaking, a representative value of the equipment life for SCR at power plants can be considered as 30 years. For other sources, the equipment life can be between 20 and 30 years. The remaining life of the boiler may also be a determining factor for the system lifetime." The updated selective non-catalytic reduction (SNCR) section of the Control Cost Manual uses a 20-year lifespan in the example analysis, based on three petroleum refiners who estimated SNCR life at between 15 and 25 years.

Draft comment 1 from ADEC cited a proposed federal rulemaking addressing a regional haze determination from EPA Region 6. The preamble to the proposed rule includes a discussion of equipment life for sulfur dioxide (SO_2) scrubbers. The preamble states that a prior Oklahoma Federal Implementation Plan (FIP) used a lifetime of 30 years to determine costs for SO_2 scrubbers. Expanding the use of the Oklahoma FIP 30-year equipment life to the UAF equipment is not appropriate because the technically feasible emission controls identified for the UAF emission units (with the exception of EU 113) do not include SO_2 scrubbers. Additionally, *emission control equipment that may be suitable for use in Oklahoma may not be suitable for use in Interior Alaska, for obvious reasons.*

A 30-year equipment life for control equipment on EU 113 is inconsistent with EPA long-standing guidance regarding equipment life determinations. The 1990 New Source Review Workshop Manual for Prevention of Significant Deterioration and Nonattainment Area Permitting states on page b.10 of Appendix B that "The economic life of a control system typically varies between 10 to 20 years and longer ***and*** *should be determined consistent with data from EPA cost support documents and the IRS Class Life Asset Depreciation Range System" (emphasis added). EU 113 will be a co-generation boiler that will produce steam for campus heat, as well as steam for the generation of electricity. Table B-1 of IRS Publication 946 (2016) provides a class life, or a tax cost recovery period, of 22 years for assets associated with Industrial Steam and Electric Generation and/or Distribution Systems (see Asset Class 00.4). As a result, a 30-year equipment life is not consistent with the EPA policy that the economic life of a control system should also be consistent with the IRS Class Life Asset Depreciation Range System.*

2. CFB Boiler: Additional SO_2 Control Technologies – The BACT analysis mentions wet scrubbing technologies, but does not clearly explain the basis for excluding these technologies (such as limestone slurry forced oxidation) from consideration within the analysis. Since wet scrubbing would be expected to represent the highest SO_2 removal efficiency, this technology must be fully evaluated within the BACT analysis. Similarly, the analysis does not evaluate dry flue gas desulfurization or dry scrubbing. This enhanced dry SO_2 control technology can achieve higher removal efficiencies than dry sorbent injection, and must also be evaluated thoroughly within the BACT analysis. The BACT analysis must include rigorous site-specific evaluation of the technical feasibility and cost effectiveness of these technologies.

UAF Response to Comment 2:

The circulating fluidized bed (CFB) boiler design includes integrated dry scrubbing control technology. The CFB boiler incorporates dry scrubbing technology by way of the limestone injection system that is inherent to the CFB design. Wet scrubbing is typically not used in conjunction with CFB technology. The RACT/BACT/LAER Clearinghouse (RBLC) database does not list any applications of wet scrubbers used with CFB boilers. Wet scrubbing is essentially a more expensive version of dry scrubbing, and therefore is only utilized for the biggest, most challenging scrubbing applications. Because dry scrubbing technology has advanced to achieving approximately the same control efficiency as wet scrubbing (90 percent or greater), the cost effectiveness for wet scrubbing would only be higher due to the higher capital cost.

Please refer to the email from David Novogoratz at Babcock and Wilcox (B&W) to John Solan on February 1, 2016 in Appendix B of the BACT analysis report. B&W indicates that dry sorbent injection (DSI) and semi-dry scrubbing are feasible post-combustion SO_2 controls for the boiler. The DSI control system evaluated in the BACT analysis is in addition to the dry scrubbing that occurs within the boiler bed.

3. CFB Boiler: SDA and DSI
   a. As part of their Oklahoma Best Available Retrofit Technology (BART) Federal Implementation Plan (FIP) final rule for regional haze, EPA Region 6 conducted significant research into the actual expected lifetime of SO_2 control technologies, including wet, semi-dry, and dry scrubbing. Region 6 found that 30 years is a reasonable estimate of actual expected equipment life for these control technologies. The analysis for SDA and DSI therefore should use 30 years unless documented evidence is provided establishing that the actual expected equipment life of the control equipment is different from this value.

      UAF response to Comment 3a:
      The Control Cost Manual does not indicate the use of a 30-year equipment life for any SO_2 emission control systems. The Control Cost Manual, Section 5.2, Chapter 1, paragraph 1.5.2, provides a 15-year equipment life for a wet scrubber, and cites Section 1 of the manual regarding capital recovery costs.

      The EPA Region 6 use of a 30-year life for SO_2 scrubbers is not necessarily consistent with the EPA Cost Control Manual or Appendix B of the 1990 New Source Review Workshop Manual, and is not a mandate for all future BACT analyses to use 30-year lifespans for SO_2 emission control systems.

      UAF does not agree that a 30-year equipment life is appropriate, as discussed in the response to Comment 1 above. As a courtesy, UAF did re-calculate the cost analysis with a basis of a 15-year equipment life. For a spray dryer absorber (SDA), the cost effectiveness would be $11,598 per ton of SO_2 avoided and for dry sorbent injection (DSI), the cost effectiveness would be $8,186 per ton of SO_2 avoided.

   b. The SDA and DSI cost analyses submitted with this analysis cite the following documents as the basis for costs and other information relied upon in the analysis, however, these documents have not been provided. These documents must be provided in order to rely upon the cited information in the analysis:
      i. "SCI engineering estimates (5 years old) for other SDAs."

         UAF response to Comment 3b(i):
         These estimates were based on a Boiler MACT compliance feasibility study prepared by SCI for a confidential client. This documentation is client confidential and cannot be provided to the agency.

      ii. "SCI engineering estimates (5 years old) for other DSI systems"

         UAF response to Comment 3b(ii):
         These estimates were based on a Boiler MACT compliance feasibility study prepared by SCI for a confidential client. This documentation is client confidential and cannot be provided to the agency.

iii. "Internal SDA cost study done by SCI in 2010, which indicated 8%."

UAF response to Comment 3b(iii):
These estimates were based on a Boiler MACT compliance feasibility study prepared by SCI for a confidential client. This documentation is client confidential and cannot be provided to the agency.

iv. "...similar internal SCI SDA cost analysis and other vendor (FTEK SCR) quotes."

UAF response to Comment 3b(iv):
These estimates were based on a Boiler MACT compliance feasibility study prepared by SCI for a confidential client. This documentation is client confidential and cannot be provided to the agency. The FTEK SCR quote was provided in Appendix B of the BACT analysis report.

v. "Internet research bulk price" for hydrated lime.

UAF response to Comment 3b(v):
The cost of $560/ton for hydrated lime was conservatively high. Based on more recent internet research, the price for bulk hydrated lime is estimated to be approximately $150/ton (lime plant value) per this website: https://minerals.usgs.gov/minerals/pubs/commodity/lime/mcs-2017-lime.pdf. Delivery to Fairbanks, Alaska would incur a higher, unknown cost. Using $150/ton in the analysis is therefore conservatively low. This adjustment results in minimal reduction to the cost effectiveness value for the use of SDA control.

vi. "Internet research bulk price" for sodium bicarbonate.

UAF Response to Comment 3b(vi):
Sodium bicarbonate price rates are available at http://www.sodaashdirect.com/buy-sodium-carbonate-online.html. The prices provided on this website do not include shipping costs. The cost of $700/ton presented in the analysis is likely conservatively low when accounting for delivery to Fairbanks, Alaska.

vii. "Current Per kW price based on GVEA data."

UAF Response to Comment 3b(vii):
The electrical utility provider in Fairbanks, Golden Valley Electric Association (GVEA) currently charges $0.209 per kilowatt-hour. The UAF BACT analysis cites $0.18 per kilowatt-hour because that particular calculation was prepared in 2016. Current GVEA rates are available at http://www.gvea.com/rates/rates.

4. CFB Boiler: SNCR

a. Within an email included in Appendix B, Babcock & Wilcox states only minimal NO_X reduction of around 10-20% would be expected from SNCR. In order to base the cost analysis on this minimal emission reduction, detailed technical justification must be submitted providing a rigorous basis for why SNCR can only achieve this smaller than average/expected emission reduction for this emission unit.

UAF Response to Comment 4a:
Babcock and Wilcox (B&W) is the boiler manufacturer for EU 113, and is the source of technical expertise about this boiler. The SNCR emission reduction efficiencies discussed in the Control Cost Manual can be quite low, particularly for coal-fired boilers with low nitrogen oxides (NO_X) concentrations at the inlet to the emission control system. (See Figures 1.1a and 1.1c in Chapter 1, Section 1 in the updated SNCR chapter of the Control Cost Manual.) B&W has significant experience providing NO_X control systems for utility boilers such as EU 113. Given the B&W involvement in the design of the UAF CFB boiler, depth of knowledge of boiler exhaust characteristics and extensive knowledge on reductions that can be achieved from an SNCR control system, B&W has the expertise to make this determination. UAF accepts the B&W expert analysis of control technology for the CFB boiler and so is not providing additional justification for the SNCR NO_X emission reduction efficiencies.

b. The SNCR cost analysis cites the following documents and information as the basis for costs and other information relied upon in the analysis, however, documentation for these values and information has not been provided. Documentation must be provided in order to rely upon the cited information in the analysis:

i. Indirect capital costs "18% was used in similar SCR BACT analysis. Assume same amount for SNCR."

UAF Response to Comment 4b(i):
The indirect capital costs are calculated using 18 percent of the total direct cost (purchased equipment and material costs and direct installation costs). The BACT analysis for the SCR systems on the combustion turbines at the Exxon Mobil Point Thomson Production Facility used the same ratio. Please see Page 23 of the Technical Analysis Report (TAR) to Permit No. AQ1201CPT01.Consistent with that ADEC-approved analysis, UAF believes that 18 percent is an appropriate ratio for the EU 113 SNCR cost analysis.

ii. "ammonia solution cost from similar BACT analysis - \$0.75/gal and specific gravity of 0.9."

UAF Response to Comment 4b(ii):
Several different references indicate that ammonia solution has a specific gravity of approximately 0.9. The BACT analysis for the SCR systems on the combustion turbines at the Exxon Mobil Point Thomson Production Facility used an ammonia

solution cost of $0.75 per gallon. Please see Page 23 of the TAR to Permit No. AQ1201CPT01. Consistent with that ADEC-approved analysis, UAF believes that a cost of $0.75 per gallon is representative of ammonia costs for this analysis.

UAF notes that if any aqueous ammonia were to be used, the concentration of that solution would be less than 20 percent. The freezing point of 19 percent aqueous ammonia is -30 degrees Fahrenheit. Ambient temperatures during winter in Interior Alaska routinely drop below -30 degrees Fahrenheit, so considerations for heat tracing, circulation, as well as shipment of the solution to Fairbanks (with the inherent risk in supply disruption) are all likely to result in higher costs.

iii. "Current Per kW price based on GVEA data."

UAF Response to Comment 4b(iii):
The electrical utility provider in Fairbanks, Golden Valley Electric Association (GVEA) currently charges $0.209 per kilowatt-hour. The UAF BACT analysis cites $0.18 per kilowatt-hour because that particular calculation was prepared in 2016. Current GVEA rates are available at http://www.gvea.com/rates/rates.

c. The budgetary nature of the costs provided by Fuel Tech (+/- 30%) is reflected in the nature of the cost effectiveness analysis methodology established in the EPA Cost Manual – it is not appropriate to include a 30% contingency factor based on this accuracy range.

UAF Response to Comment 4c:
The capital costs for an SNCR system on the CFB boiler were provided by Babcock & Wilcox (B&W). The B&W estimate did not include any contingency costs. Because preparing a BACT analysis requires obtaining vendor pricing information without knowing the exact final emission limits, the vendor could not be provided with a precise emissions target. The vendor therefore must rely upon their general experience of what percent reduction could be achieved by an SNCR system. Applying a contingency factor in the cost effectiveness evaluation is both practical and appropriate. Use of a contingency factor for costs associated with control device retrofits is also consistent with a Boiler MACT compliance feasibility study prepared by SCI for a confidential client with six coal-fired boilers. Please see also the UAF response to Comment 4b(ii) above.

A contingency cost of 30 percent was applied to equipment and material costs, direct installation costs, and engineering and procurement costs in the BACT analysis for the SCR systems on the combustion turbines at the Exxon Mobil Point Thomson Production Facility. Please see Page 23 of the Technical Analysis Report (TAR) to Permit No. AQ1201CPT01.Consistent with that ADEC-approved analysis, UAF believes that 30 percent is an appropriate ratio for the EU 113 SNCR cost analysis.

5. CFB Boiler: SCR – The EPA has recently updated the cost manual chapter pertaining to SCR,

and developed a cost spreadsheet to be used for evaluation of this technology for cost effectiveness. The cost analysis submitted as part of this BACT analysis does not use the EPA cost spreadsheet. Specific comments related to the SCR cost effectiveness analysis include the following:

a. The recently updated cost manual chapter covering SCR includes information regarding SCR equipment life, and indicates the technology can be expected to last 30 years. The analysis should use 30 years as the equipment life for SCR unless documented evidence is provided establishing that the actual expected equipment life of the control equipment is different from this value.

   UAF Response to Comment 5a:
   The updated SCR section of the Control Cost Manual states "broadly speaking, a representative value of the equipment life for SCR at power plants can be considered as 30 years. For other sources, the equipment life can be between 20 and 30 years. The remaining life of the boiler may also be a determining factor for the system lifetime."

   UAF does not agree that a 30-year equipment life is appropriate, as discussed in the response to Comment 1 above. As a courtesy, UAF did re-calculate the cost analysis with a basis of a 20-year equipment life. For selective catalytic reduction (SCR), the cost effectiveness would be $22,232 per ton of NO_X emissions avoided.

b. The BACT analysis as submitted states that the normal exhaust temperature from the CFB boiler is expected to be 1,550-1,650°F. This factor is listed as a technical feasibility issue for SCR as a potential control technology since the temperature range for SCR is listed as 500-800°F. Please provide a technical explanation of why the boiler exhaust temperature is so high, and why additional heat recovery has not been included in the design of the new power plant. The analysis must also include thorough analysis of high temperature SCR with respect to technical feasibility and cost effectiveness.

   UAF Response to Comment 5b:
   The BACT analysis report correctly states on page 11 that the boiler combustion temperature is expected to range between 1,550 and 1,650 °F. UAF acknowledges that the description of the exhaust gas temperature provided on page 12 of the BACT analysis is not accurate.

   Stanley Consultants contacted Babcock and Wilcox (B&W) to seek clarification of exhaust gas characteristics. B&W indicated that the predicted flue gas temperatures at maximum combustion rate (MCR) conditions for the CFB boiler as listed on the performance summary sheet for the boiler are as follows:

   - *Exit of generating bank* 774°F
   - *Inlet of economizer* 774°F
   - *Exit of economizer* 463°F
   - *Exit of air preheater* 335°F

The ideal gas temperature for NO_X reduction ranges for SCR is from 700 to 750°F. (Steam – Its Generation and Use, Babcock & Wilcox, 42nd Edition, 2015). In utility boilers, the typical SCR system would be placed at the economizer outlet, preceding the air heater. As shown in the above temperature profile, the exit temperature at the economizer outlet is well below the ideal range. The exhaust flow coming out of the boiler is closer to this documented range, however design modifications would be needed to fit the SCR system into this arrangement and would involve a redesign of structure of the baghouse building to accommodate the installation of the SCR above the baghouse. Given the seismic design criteria of the site, this would be a challenging and expensive undertaking. These unique characteristics only serve to drive up capital costs and consequently the cost effectiveness value of the SCR control system.

c. The SCR cost analysis cites the following documents and information as the basis for costs and other information relied upon in the analysis, however, documentation for these values and information has not been provided. Documentation must be provided in order to rely upon the cited information in the analysis:

   i. "Cost of startup spares indicated as a percentage of equipment cost per similar project."

   UAF Response to Comment 5c(i):
   The cost of startup spares was estimated as a percentage of equipment cost in a similar project. The UAF consultant indicates that the project was prepared for a confidential client. UAF believes that the cost for startup spare equipment estimated at 0.50 percent of total equipment costs is reasonable for purposes of this analysis.

   ii. Fab Site Vendor "days based on similar project".

   UAF Response to Comment 5c(ii):
   The fabrication site vendor representative fees were assumed to be comparable to those fees from a similar project. The UAF consultant indicates that the project was prepared for a confidential client. UAF believes that these vendor fees are reasonable for purposes of this analysis.

   iii. Onsite Vendor "days based on similar project".

   UAF Response to Comment 5c(iii):
   The onsite vendor representative fees were assumed to be comparable to those fees from a similar project. The UAF consultant indicates that the project was prepared for a confidential client. UAF believes that these vendor fees are reasonable for purposes of this analysis.

   iv. Indirect capital costs "18% was used in similar SCR BACT analysis for smaller CTs."

UAF Response to Comment 5c(iv):
The indirect capital costs are calculated using 18 percent of the total direct cost (purchased equipment and material costs and direct installation costs). The BACT analysis for the SCR systems on the combustion turbines at the Exxon Mobil Point Thomson Production Facility used the same ratio. Please see Page 23 of the Technical Analysis Report (TAR) to Permit No. AQ1201CPT01.Consistent with that ADEC-approved analysis, UAF believes that 18 percent is an appropriate ratio for the EU 113 SNCR cost analysis.

v. "ammonia solution cost from similar BACT analysis - $0.75/gal and specific gravity of 0.9."

UAF Response to Comment 5c(v):
Several different references indicate that ammonia solution has a specific gravity of approximately 0.9. The BACT analysis for the SCR systems on the combustion turbines at the Exxon Mobil Point Thomson Production Facility used an ammonia solution cost of $0.75 per gallon. Please see Page 23 of the TAR to Permit No. AQ1201CPT01. Consistent with that ADEC-approved analysis, UAF believes that a cost of $0.75 per gallon is representative of ammonia costs for this analysis.

UAF notes that if any aqueous ammonia were to be used, the concentration of that solution would be less than 20 percent. The freezing point of 19 percent aqueous ammonia is -30 degrees Fahrenheit. Ambient temperatures during winter in Interior Alaska routinely drop below -30 degrees Fahrenheit, so considerations for heat tracing, circulation, as well as shipment of the solution to Fairbanks (with the inherent risk in supply disruption) are all likely to result in higher costs.

vi. "Current Per kW price based on GVEA data."

UAF Response to Comment 5c(vi):
The electrical utility provider in Fairbanks, Golden Valley Electric Association (GVEA) currently charges $0.209 per kilowatt-hour. The UAF BACT analysis cites $0.18 per kilowatt-hour because that particular calculation was prepared in 2016. Current GVEA rates are available at http://www.gvea.com/rates/rates.

vii. "Replacement labor based on similar project."

UAF Response to Comment 5c(vii):
The catalyst replacement manhours were assumed to be comparable to those manhours determined in a similar project. The UAF consultant indicates that the project was prepared for a confidential client. UAF believes that the labor hour estimate is appropriate for purposes of this analysis.

viii. "Labor cost based on similar project."

UAF Response to Comment 5c(viii):
The catalyst replacement labor rate was assumed to be comparable to the catalyst replacement labor rate determined in a similar project. The UAF consultant indicates that the project was prepared for a confidential client. The labor rate is likely conservatively low because the cost is not reflective of 2017 labor rates. UAF believes the rate is representative of labor costs for purposes of this analysis.

d. The budgetary nature of the costs provided by FuelTech (+/- 30%) is reflected in the nature of the cost effectiveness analysis methodology established in the EPA Cost Manual – it is not appropriate to include a 30% contingency factor based on this accuracy range.

UAF Response to Comment 5d:
The capital costs for an SCR system on the CFB Boiler were provided by Babcock & Wilcox (B&W). The estimate did not include any contingency costs. B&W did indicate that minimal space for an SCR retrofit is available. The arrangement to add SCR would be very complicated arrangement. This issue was not otherwise factored into the budgetary estimates provided. Because preparing a BACT analysis requires obtaining vendor pricing information without knowing the exact final emission limits, the vendor could not be provided with a precise emissions target. The vendor therefore must rely upon their general experience of what percent reduction could be achieved by an SCR system. Applying a contingency factor in the cost effectiveness evaluation seems both practical and appropriate. Use of a contingency factor for costs associated with control device retrofits is also consistent with a Boiler MACT compliance feasibility study prepared by SCI for a confidential client with six coal-fired boilers. Please see also the UAF response to Comment 5c(v) above.

A contingency cost of 30 percent was applied to equipment and material costs, direct installation costs, and engineering and procurement costs in the BACT analysis for the SCR systems on the combustion turbines at the Exxon Mobil Point Thomson Production Facility. Please see Page 23 of the Technical Analysis Report (TAR) to Permit No. AQ1201CPT01.Consistent with that ADEC-approved analysis, UAF believes that 30 percent is an appropriate ratio for the EU 113 SNCR cost analysis.

UAF notes that removing the contingency factor from the cost analysis calculation results in a cost effectiveness of \$28,425/ton of NO_X removed (as opposed to \$23,915/ton when including the 30 percent contingency). Disuse of the contingency factor does not alter the result that SCR cannot be determined to be BACT for EU 113.

6. <u>EU 3 Mid-Sized Diesel Boiler: PTE</u> – Detailed basis must be provided for the NO_X PTE of 138.8

tpy for EU 3 used in the calculations. Note that page 19 of the Title V statement of basis states that emissions from this boiler "in terms of ton/yr were never and will not be limited". Based on the proposed BACT limit of 0.2 lb/MMBtu for good combustion practices, it appears the PTE should, at a minimum, reflect full load operation at this emission rate for 8,760 hours/year (about 158 tpy). If PTE is based on the baseline emission rate used in the FuelTech quote (0.175 lb/MMBtu), the BACT limit proposed for good combustion practices should be 0.175 lb/MMBtu as well.

UAF Response to Comment 6:

The baseline NO_X emission rate of 0.175 lb/MMBtu is an emission rate which Fuel Tech used to prepare a cost estimate for an SCR system. Assuming an existing NO_X emission rate for EU 3 was necessary to prepare a cost estimate for a NO_X emission control system. (The vendor could also not be provided with a precise emissions target, because the nature of a BACT analysis requires obtaining vendor pricing without knowing the exact final emission limit.) The baseline NO_X emission rate of 0.175 lb/MMBtu is not a vendor-guaranteed emission rate. Fuel Tech is the SCR controls system vendor but is not the vendor that manufactured EU 3.

EU 3 was installed in 1970 and is almost 50 years old. NO_X emission rates depend on combustion efficiency, the amount of fuel-bound nitrogen, and several other factors. The exact NO_X emission profile of EU 3 is not known. (Please refer to the letter from Indeck dated February 5, 2016, provided in Appendix B of the UAF BACT analysis.) UAF does not wish to commit to a BACT limit which is less than 0.2 lb/MMBtu due to these unknowns. (The 40 CFR 60 Subpart Db NSPS NO_X emission limit is also 0.2 lb/MMBtu. The AP-42 emission factor of 24 lb/1,000 gallons of diesel (Table 1.3-1) is dependent on fuel heat content. Assuming a diesel heating value of 0.137 MMBtu/gallon, the resulting emission rate is 0.175 lb/MMBtu, which is less than the NSPS limit.) UAF believes that 0.2 lb/MMBtu is an appropriate and reasonable BACT limit for EU 3, given the age of the boiler and the unknown variables involved.

7. EU 3 Mid-Sized Diesel Boiler: LNB/FGR
   a. This technology is eliminated based on cost effectiveness calculated assuming actual emissions. All cost analyses and BACT determinations must be based on PTE.

   UAF Response to Comment 7a:

   The cost analysis for LNB/FGR emission controls on EU 3 based on potential to emit (PTE) is presented in the BACT report that UAF submitted to ADEC. The cost effectiveness of LNB/FGR for EU 3 is $3,634 per ton of NO_X removed, as shown in Table 3-18 and discussed on page 40 of the report.

   EU 3 is oil-fired and is operated as a backup boiler. Recent actual NO_X emissions are less than five percent of PTE for EU 3. The new CFB boiler, EU 113, which is currently being installed, will be more reliable than the existing coal-fired boilers which have been the primary source of steam at the UAF Central Heat and Power Plant (CHPP). EU 3 will continue in this backup role and so is not expected to be operated often. The actual emissions reductions achieved through installing LNB/FGR would be *minimal (i.e., less than 4 tons per year of NO_X removed). The effective cost of installing the controls would be approximately $35,500 per ton of NO_X removed, as discussed on page 41 of the report.*

UAF understands that BACT cost analyses are typically based on PTE as opposed to actual emissions. UAF also understands that BACT decisions are based on case-by-case analysis. As a result, an exception to this typical approach is appropriate in this case because:

- *EU 3 has a long history of infrequent use as backup boiler;*
- *The installation of EU 113 is expected to further reduce the operating frequency of EU 3; and*
- *The cost effectiveness of installing LNB/FGR equipment on EU 3 is very high based on the expected infrequent operation of this boiler.*

As a practical matter, the analysis demonstrates that installing LNB/FGR equipment on EU 3 is not a cost effective method to reduce NO_X emissions from EU 3.

b. On page 39, the BACT analysis describes this control option as "installation of a new burner on the boiler that is already equipped with a LNB and FGR". The analysis must clarify the current status of the boiler with respect to LNB and FGR technology. If the boiler is already equipped with FGR, detailed technical justification must be provided regarding why the fan(s) and/or ducting must be replaced.

UAF Response to Comment 7b:
UAF acknowledges that the description provided on page 39 of the BACT analysis is not accurate. EU 3 is not equipped with LNB or FGR technology. The letter from Indeck dated February 5, 2016, provided in Appendix B of the report, states the following. "The low NO_X burners offered here may be operated with the existing boiler force draft (FD) fans with some possible shortness of full MCR steam rating due to the settings of the existing equipment. If lower NOx levels are desired, these FD fans must be replaced with new FD fans and motors designed to allow for induced flue gas recirculation (FGR) from the boiler flue gas outlet. Optional pricing for these FD fans with FGR capability is provided."

In the letter, Indeck provided information about the existing burners, new LNB without FGR, and new LNB with FGR. The letter states that installing FGR would require the replacement of the existing forced draft (FD) fan and motor.

8. EU 3 Mid-Sized Diesel Boiler: SCR
   a. The SCR cost analysis cites the following documents and information as the basis for costs and other information relied upon in the analysis, however, documentation for these values and information has not been provided. Documentation must be provided in order to rely upon the cited information in the analysis:
      i. "December 2015 price according to Farmer's Coop Association."

UAF Response to Comment 8a(i):
The Farmer's Coop Association price web page is available at http://www.farmersco-op.coop/pages/custom.php?id=21023. Although prices change slightly over time, UAF believes the $356 cost per ton of urea is representative for this analysis.

ii. "Replacement labor based on similar project."

UAF Response to Comment 8a(ii):
The catalyst replacement manhours and labor rate were assumed to be comparable to the manhours determined in a similar project. The UAF consultant indicates that the project was prepared for a confidential client. UAF believes that the labor hour cost estimate for catalyst replacement is appropriate for purposes of this analysis.

iii. Transport cost direct to site (SCR catalyst). "Based on similar project."

UAF Response to Comment 8a(iii):
The catalyst transportation cost was assumed to be comparable to transport costs determined in a similar project. The UAF consultant indicates that the project was prepared for a confidential client. UAF believes that the catalyst transport cost estimate is appropriate for purposes of this analysis.

iv. Transport cost for spent SCR catalyst. "Based on similar project."

UAF Response to Comment 8a(iv):
The transportation cost for the spent catalyst is assumed to be the same as the transportation cost for a replacement catalyst to UAF.

b. No basis is provided for the SCR freight cost of $20,000.

UAF Response to Comment 8b:
The $20,000 freight cost was based on the cost of freight for a smaller SCR application on the ACEP Generator Engine, EU 27. Please refer to the email from Erick Pomrenke at NC Power Systems to Lain Pacini on November 12, 2015 in Appendix B of the BACT analysis report. NC Power Systems states that freight costs would be in the range of $9,000 to $12,000. The BACT analysis for EU 3 assumes that the SCR system for a larger emission unit would weigh more and consequently have higher freight costs for shipment. The freight cost for an SCR system on EU 3 has been scaled up from the cost provided by NC Power Systems.

c. Initial performance testing cost is included twice.

<u>*UAF Response to Comment 8c:*</u>

The performance testing cost of $10,000 was inadvertently included twice. In the cost analysis, testing was shown under Direct Costs (1)(b) "NO_X CEMS Certification Testing" and then again under Indirect Costs (4) "Performance Tests." Correcting the cost analysis to remove the duplicate cost has minimal impact on the calculated cost effectiveness of the control system. The cost effectiveness value changes from $8,416 to $8,400 per ton of NO_X removed.

d. The budgetary nature of the costs provided by FuelTech (+/- 30%) is reflected in the nature of the cost effectiveness analysis methodology established in the EPA Cost Manual – it is not appropriate to include a 30% contingency factor based on this accuracy range.

<u>*UAF Response to Comment 8d:*</u>

The accuracy range of the Fuel Tech cost estimate is unrelated to the contingency factor. Vendors provide these accuracy ranges because the vendors know certain factors cannot be accounted for in the cost in the absence of any substantial design work. An example of this issue would be any special structural material costs to accommodate seismic requirements, which certainly exist in this application in Interior Alaska.

UAF believes that the use of the 30 percent contingency factor is appropriate due to the following elements:

- *The age of EU 3, its ancillary equipment, and the building envelope in this part of the CHPP. EU 3 was installed in 1970. Installing emission controls (or any new equipment) on this boiler in this portion of the plant requires appropriate contingency to address unforeseen issues which are likely to arise when dealing with a facility which is 50 years old.*
- *A contingency cost of 30 percent was applied to equipment and material costs, direct installation costs, and engineering and procurement costs in the BACT analysis for the SCR systems on the combustion turbines at the Exxon Mobil Point Thomson Production Facility. Please see Page 23 of the Technical Analysis Report (TAR) to Permit No. AQ1201CPT01.Consistent with that ADEC-approved analysis, UAF believes that 30 percent is an appropriate ratio for the EU 3SCR cost analysis.*
- *Because preparing a BACT analysis requires obtaining vendor pricing information without knowing the exact final emission limit, the vendor could not be provided with a precise emissions target. The vendor therefore must rely upon their general experience of what percent reduction could be achieved by an SCR system. Applying a contingency factor in the cost effectiveness evaluation seems both practical and appropriate. Use of a contingency factor for costs associated with control device retrofits is also consistent with a Boiler MACT compliance feasibility study prepared by SCI*

for a confidential client with six coal-fired boilers.

- *The use of urea requires the consideration of material handling, storage, energy requirements for dissolving urea into solution, and maintaining that liquid solution during cold weather months in Interior Alaska. These issues are all likely to result in higher costs.*

UAF notes that removing the contingency factor from the cost analysis calculation results in a cost effectiveness of $7,261/ton of NO_X removed (as opposed to $8,416/ton when including the 30 percent contingency). As discussed in Section 3.5 of the BACT analysis report, UAF believes that the cost estimate for SCR on EU 3 is low. Additionally, the actual emission reductions that would be achieved through installing SCR would be minimal (i.e., less than 6 tons per year of NO_X removed). Please refer to the response to Comment 7a above. The effective cost of installing SCR on EU 3 would be approximately $144,000 per ton of NO_X removed when considering the backup role of EU 3 and the expectation that EU 3 will continue to operate at a very low capacity factor.

9. EU 3 Mid-Sized Diesel Boiler: ULSD – The ULSD cost analysis is based on "review of UAF's fuel costs from FY 2011 through 2016. Average of the FY 2014 through 2016 is used, which is 28 cents per gallon more to use ULSD." The documents forming the basis for this information must be submitted in order to rely on this information for purposes of the analysis.

UAF Response to Comment 9:
The fuel prices used in the ULSD cost analysis were obtained from the Oil Price Information Service (OPIS) through the website at https://www.opisnet.com/.

10. EU 8 Large Diesel Fired Engine: Operational Scenario – The NO_X BACT analysis for this unit applies the facility-requested 40 ton per year emission limit, and bases the analysis on an assumed NO_X reduction of only 36 tons (90% reduction from 40 tpy). However, the analysis assumes that the unit operates 8,760 hours/year when calculating the annual O&M costs (i.e., see aqueous ammonia cost). The assumptions underlying the cost analysis are therefore inconsistent. The cost effectiveness analysis must be revised to be consistent based on the assumed operational scenario for the unit. For example, if the unit is assumed to operate uncontrolled for NO_X up to the 40 ton/year limit, the corresponding costs associated with only those limited number of hours may be included. This applies to all annual operating & maintenance costs, including catalyst life.

UAF Response to Comment 10:
EU 8 does not have an operating limit that directly restricts operating hours. As a practical matter, UAF agrees that the 40 tpy NO_X emission limit would likely result in engine operating hours which are less than 8,760 hours per year. UAF also notes that the standard methodology of preparing a BACT analysis is not realistic in this case, because the 40 tpy NO_X limit remains in effect. Requiring the use of SCR to reduce the NO_X emission rate from EU 8 will not result in an overall emissions reduction. With an emissions reduction of zero tons per year, a cost effectiveness

value cannot be calculated:

Cost effectiveness = (Total Annualized Costs, $) / (Tons of Pollutant Avoided, tpy)

If the denominator of this fraction is zero, no emission control can be determined to be cost effective and therefore BACT. As addressed in Section 3.5 of the BACT analysis report, UAF recommends that the BACT limit require the use of the existing turbocharger, aftercooler, and operations under the existing 40 tpy NO_X limit.

11. <u>EU 8 Large Diesel Fired Engine: SCR</u> – Please provide detailed information regarding the visible emissions described in the BACT analysis which were observed during operation of the SCR currently installed on the large diesel engine. See page 19.

<u>UAF Response to Comment 11:</u>
The visible emissions from EU 8 originate from the Heat Recovery Steam Generator (HRSG), not the existing SCR system. Modifications to the exhaust system would be necessary to enable use of the existing SCR system. For more information on the visible emissions concern, please refer to the Compliance Order by Consent (COBC) dated effective September 25, 2015. (ADEC Enforcement Tracking No. 12-1016-50-0002)

An amendment to the COBC was executed in April 2016 to allow operations of EU 8 following specific maintenance events as recommended by the manufacturer. EU 8 operated for 89 minutes in May 2016 following an overhaul. UAF conducted a Method 9 visible emission observation during the engine run, which indicated excess visible emissions. UAF reported the observations to ADEC as required. Otherwise, EU 8 has not been operated and cannot be operated (except for validation of maintenance events per the COBC amendment).

12. <u>EU 8 Large Diesel Fired Engine: DPF and SCR</u> – The BACT analysis identifies back pressure as a potential technical challenge of installing a DPF to a large diesel engine such as EU 8, but provides no technical analysis or other quantitative or analytical basis for this argument. Further, the BACT analysis determines that an appropriate DPF "likely does not exist" without citing any information from established DPF equipment suppliers. The BACT analysis cites only a single local Fairbanks engine company, whose employee states that the company has "never supplied a DPF with a new engine or for aftermarket use". The information provided forms insufficient basis to reject DPF as technically infeasible and/or not cost effective. The analysis must provide detailed technical analysis of the backpressure issue by an engineering firm or control equipment supplier with the necessary expertise regarding the control technology. In order to establish the availability of a suitable DPF, the analysis must include information regarding these topics from established DPF control equipment suppliers. The availability of this control technology is not limited to DPF equipment currently available "off the shelf". UAF must explore whether manufacture of an appropriate DPF for this emission unit is technically feasible, and conduct an emission unit specific cost analysis following the EPA Cost Manual.

<u>UAF Response to Comment 12:</u>

EU 8 is a Fairbanks Morse Colt-Pielstick engine. Fairbanks Morse Engine (FME) is a well-established engine manufacturer with considerable technical expertise. FME is not a local Fairbanks engine company. FME is based in Wisconsin and was founded more than 140 years ago. More information on FME is available at www.fairbanksmorse.com.

According to information from an FME representative, a diesel particulate filter (DPF) device is not a commercially available technology for this engine. Please refer to the email from Joe Rubino to Julie Ackerlund of February 24, 2016 in Appendix B of the BACT analysis, which documents the discussion between SCI and FME. As stated in section 4.2.4 of the BACT analysis, the RBLC database has no entries for DPF devices installed on large diesel-fired engines. DPF is not currently technically feasible due to the backpressure which results when a filtration system is added to the exhaust stream. Because the UAF research indicates that a DPF device for EU 8 is neither commercially available nor technically feasible, a cost analysis for DPF technology will not be prepared.

Please note that UAF provided a BACT analysis for $PM_{2.5}$ direct emissions as a courtesy even though the analysis is not required. The UAF campus stationary source is not a nonattainment major source of $PM_{2.5}$, as described in Section 1.0 of the BACT analysis. As a result, direct $PM_{2.5}$ emissions do not trigger the requirement to prepare a BACT analysis, and BACT limits for $PM_{2.5}$ emissions from emission units at UAF are not required elements of the State Implementation Plan (SIP).

13. <u>EU 27 ACEP Generator</u> – The BACT analysis includes evaluations of SCR and DPF as applied individually for control of NO_X and $PM_{2.5}$ respectively, from this emission unit, however a combination SCR/DPF was not evaluated. The analysis must be revised to include a cost effectiveness analysis for this combined control technology.

    <u>UAF Response to Comment 13:</u>
    NC Power Systems supplied a capital cost for a combined SCR/DPF control system along with the cost estimate for the separate DPF and SCR packages. Please refer to the email from Erick Pomrenke at NC Power Systems to Lain Pacini on November 11, 2015 in Appendix B of the BACT analysis report. UAF has prepared a cost effectiveness analysis using the combined SCR/DPF capital cost. The analysis uses the existing SCR cost analysis submitted in the BACT report as a starting point and adjusts for the increased capital cost and the mass of pollutants controlled to account for a combined $NO_X/PM_{2.5}$ emission reduction. The cost effectiveness for a combined SCR/DPF is not economically feasible. The cost effectiveness is $11,340 per ton of pollutant (NO_X and $PM_{2.5}$) removed. This cost analysis is presented in Attachment A.

    Please note that UAF provided a BACT analysis for $PM_{2.5}$ direct emissions as a courtesy even though the analysis is not required. The UAF campus stationary source is not a nonattainment major source of $PM_{2.5}$, as described in Section 1.0 of the BACT analysis. As a result, direct $PM_{2.5}$ emissions do not trigger the requirement to prepare a BACT analysis, and BACT limits for $PM_{2.5}$ emissions from emission units at UAF are not required elements of the SIP.

ADEC Draft Comments

12. For the purposes of this BACT analysis the cost analysis for each emissions control for each of EUs 4 and 8 should be based on the assumption that the 40 tpy NOx limit will be consumed by the EU being evaluated. Under the current permitting limit it is possible for one of EUs 4 and 8 to be the sole contributor to the 40 tpy of NOx in any given 12 month rolling period. Additionally, the 10 percent capacity limit for EU 4 was removed with the issuance of Minor Permit No. AQ0316MSS04 on August 4, 2016, and is therefore no longer applicable as limited operation for EU 4. Please revise the PTE and cost analysis for these units.

    UAF Response to ADEC Comment 12:

    The 10 percent capacity factor limit on EU 4 remains in effect. Please refer to Conditions 17 and 41.2 of Permit No. AQ0316TVP02, Revision 1, and page 20 in the Statement of Basis for the Title V permit. The capacity factor limit is an owner requested limit (ORL) which enables EU 4 to be exempt from a NO_X emission standard and monitoring requirements in the New Source Performance Standards (NSPS) in 40 Code of Federal Regulations (CFR) 60 Subpart Db. Permit No. AQ0316MSS04 was issued on February 15, 2013, and addresses EUs 9A, 19, 20, and 21. That permit did not address EU 4 and did not remove the 10 percent capacity factor limit. Permit No. AQ0316MSS05 was issued on August 4, 2016 and does not include the capacity factor limit. Per item 4 under Section 4 of the Technical Analysis Report for Permit No. AQ0316MSS05, the NSPS requirements are not included in the minor permit because those requirements have since been incorporated into the operating permit. As a result, the PTE and cost analyses for EU 4 in the BACT analysis are correctly based on the 10 percent capacity factor limit. (Refer to Tables 1-3, 1-5, 3-3, 3-13, 5-3, and 5-9 in the analysis report.)

    With respect to EU 8, baseline NO_X and SO_2 PTE are each set at 40 tpy to reflect that EU 8 could consume either or both of the entire NO_X and/or SO_2 annual emission limits. Please refer to Tables 1-2, 1-3, 1-5, 3-3, and 5-3. No revisions to the PTE or cost analyses for EU 8 are needed as a result.

13. Describe for each emission unit type, what constitutes good combustion practices. Include any work or operational practice that will be implemented and describe how continuous compliance with good combustion practices will be achieved.

    UAF Response to ADEC Comment 13:

Emission Unit Type

- ***Mid-sized Diesel-Fired Boilers*** *(EUs 3 and 4) – 180.9 MMBtu/hr*
    - *Optimize air to fuel ratio.*
    - *Conduct regular maintenance.*
    - *Regular Cleaning of Boiler.*
        - *Any residue, such as soot or scale that coats the heat transfer surfaces of the boiler will reduce its efficiency and also increase the likelihood of equipment*

failure. Cleaning this surface according to manufacturer's recommendations is important to maintaining optimum boiler performance and equipment life.

- *Water Chemical Treatment*
  - *Good boiler water chemical treatment, depending on the dissolved minerals in the makeup of the water.*
  - *Poor water treatment practices can result in scale accumulation on the water side of the tubes.*
  - *Annual inspections of boilers should include a thorough examination of the water side surfaces for evidence of scaling and corrosion. Even a thin layer of scale interferes with heat transfer and thereby decreases combustion efficiency.*
- *Minimize Boiler Blowdown*
  - *Having too many total dissolved solids (TDS's) in the boiler water can cause scale and reduce boiler efficiency. Therefore, it is necessary to maintain the solids below certain limits.*
  - *Excessive blowing down will reduce useful output and lower efficiency.*

- ***Large Diesel-Fired Engine** (EU 8) – 13,266 hp*
  - *Optimize air to fuel ratio.*
  - *Operate the engine such that the following combustion air management conditions are met:*
    - *a sufficient quantity of oxygen is available to ensure complete combustion,*
    - *a sufficient amount of diluent (i.e., EGR) is present to control the combustion temperature,*
    - *the temperature and pressure (density) of the charge air is controlled,*
    - *suitable bulk motion and kinetic energy is imparted to the charge air in the cylinder to support the mixing of air, fuel and intermediate combustion products, and*
    - *the size and concentration of impurities such as dust and dirt is acceptable.*
  - *Manage the charge air temperature by:*
    - *Cooling high temperature air in boosted diesel engines and*
    - *Heating low temperature air to facilitate engine start-up and warm-up at low ambient temperatures.*
  - *Preheat engine.*
  - *Balance cylinder firing pressures.*
  - *Recirculate exhaust gas back into the intake system.*
- ***Medical/Pathological Waste Incinerator** (EU 9A)*
  - *EUs will be operated and maintained in accordance with manufacturer specification.*
- ***Small Boiler** (EUs 19 – 21)*
  - *EUs will be operated and maintained in accordance with manufacturer specification.*
- ***Small Engine** (EU 27)*
  - *EUs will be operated and maintained in accordance with manufacturer specification.*
- ***Large Coal-Fired Boiler** (EU 113) – 295.6 MMBtu/hr*
  - *Optimize air to coal ratio by reducing excess air or excess O2.*
  - *Minimize air-in leakage and air heater cross leakage to minimize fan power and flue gas heat losses.*
  - *Optimize coal fineness and moisture content based on the coal being burned in the unit.*
  - *Maintain boiler burners such that fuel distribution is evenly dispersed.*
  - *Maintain good water quality to prevent fouling of tube surfaces and poor heat transfer.*

- *Inspect and maintain insulation, boiler tubes, and access door seals.*

THE STATE of ALASKA
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September 13, 2018

Frances Isgrigg, Director
Environmental Health, Safety & Risk Management
University of Alaska Fairbanks
PO Box 758145
Fairbanks, AK 99775

Subject: Request for additional information for the Best Available Control Technology Technical Memorandum for University of Alaska Fairbanks by November 1, 2018

Dear Ms. Isgrigg:

A portion of the Fairbanks North Star Borough (FNSB) has been in nonattainment with the 24-hour National Ambient Air Quality Standard for fine particulate matter ($PM_{2.5}$) since 2009. In a letter dated April 24, 2015, I requested that the University of Alaska Fairbanks and other affected stationary sources voluntarily provide the Alaska Department of Environmental Conservation (ADEC) with a Best Available Control Technology (BACT) analysis in advance of the nonattainment area being reclassified to a Serious Area. On May 10, 2017, the US Environmental Protection Agency (EPA) published their determination that the FNSB $PM_{2.5}$ nonattainment area would be reclassified from a Moderate Area to a Serious Area effective June 9, 2017.[1]

Once the nonattainment area was reclassified to Serious, it triggered the need for Best Available Control Measure (BACM)/BACT analyses. A BACM analysis requires that ADEC review potential control measure options for the various sectors that contribute to the $PM_{2.5}$ air pollution in the nonattainment area. A BACT analysis must be conducted for applicable stationary sources such as the University of Alaska Fairbanks. BACM and BACT are required to be evaluated regardless of the level of contribution by the source to the problem or its impact on the areas ability to attain.[2] The BACT analysis is a required component of a Serious State Implementation Plan (SIP).[3] ADEC sent an email to Ms. Isgrigg on May 11, 2017 notifying her of the reclassification to Serious and included

[1] Federal Register, Vol. 82, No. 89, Wednesday May 10, 2017 (https://dec.alaska.gov/air/anpms/comm/docs/2017-09391-CFR.pdf)

[2] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf, Clean Air Act 189 (b)(1)(B) and 189 (e) and CFR 51.1010(4)(i) require the implementation of BACT for point sources and precursors emissions and BACM for area sources.

[3] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf, Clean Air Act 189 (b)(1)(B) and 189 (e) require the implementation of BACT for point sources and precursors emissions and BACM for area sources

a request for the BACT analysis to be completed by August 8, 2017. The BACT analysis was submitted by email to ADEC on February 8, 2017 from University of Alaska Fairbanks. It included emission units found in Operating Permit AQ0316TVP02 Revision 1 and Minor Permit AQ0316MSS06 Revision 2.

On March 22, 2018, ADEC released a preliminary draft of the BACT determination for the University of Alaska Fairbanks for public discussion on its website at: http://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-serious-sip-development. As indicated in the release, this document is a work in progress. ADEC received additional information from the University of Alaska Fairbanks and the EPA on the preliminary draft BACT determination and expects to make changes to the determination based upon this input. Therefore, ADEC is requesting additional information from the University of Alaska Fairbanks to assist it in making a legally and practicably enforceable BACT determination for the source.

Specifically, ADEC requests that the University of Alaska Fairbanks review the cost effectiveness spreadsheet provided as a part of the preliminary SO_2 BACT determination which was originally developed by Sargent & Lundy (S&L) in 2010. The spreadsheet includes a link to the S&L white paper that provides a basis for the cost effectiveness calculations and indicates that the model is intended to calculate estimated total project cost (total capital cost of installation), as well as direct and indirect annual operating costs. These calculations are largely based on the estimated usage of sorbent and the gross generating capacity of the plant. Please use this spreadsheet to calculate the cost effectiveness of SO_2 removal in dollars per ton and identify all assumptions and technical justifications used in the analysis.

If ADEC does not receive a response to this information request by November 1, 2018, ADEC will make a preliminary BACT determination based upon the information originally provided. However, ADEC does not have the in depth knowledge of your facility's infrastructure and without additional information, may select a more stringent BACT for your facility in order to be approvable by EPA. It is ADEC's intent to release the preliminary BACT determinations for public review along with any precursor demonstrations and BACM analyses before the required public comment process for the Serious SIP. In order to provide this additional comment opportunity, ADEC must adhere to a strict schedule. Your assistance in providing the necessary information in a timely manner is greatly appreciated.

After ADEC makes a final BACT determination for the University of Alaska Fairbanks, it must include the determination in Alaska's Serious SIP that then ultimately requires approval by EPA.[4] In addition, the BACT implementation 'clock' was also triggered by the EPA reclassification of the area to Serious on June 9, 2017. Therefore, the control measures that are included in the final BACT determination will be required to be fully implemented prior to June 9, 2021 - 4 years after reclassification.[5]

As indicated in a meeting on September 21, 2017 between ADEC Air Quality staff and the stationary sources affected by the BACT requirements, ADEC will also be using the information submitted or developed to support the BACT determinations for Most Stringent Measure (MSM) consideration. MSMs will be a required element of the state implementation plan if the State applies

[4] https://www.gpo.gov/fdsys/pkg/USCODE-2013-title42/html/USCODE-2013-title42-chap85-subchapI-partD-subpart4-sec7513a
[5] 40. CFR 51.1010(4)

for an extension of the attainment date from EPA. Therefore, the information you submit will be used for both analyses.

ADEC appreciates the cooperation that we've received from the University of Alaska Fairbanks. ADEC staff would like to continue periodic meetings to keep track of timelines and progress. If you have any questions related to this request, please feel free to contact us. Deanna Huff (email: Deanna.huff@alaska.gov) and Cindy Heil (email: Cindy.heil@alaska.gov) are the primary contacts for this effort within the Division of Air Quality.

Sincerely,

BY OR

Denise Koch, Director
Division of Air Quality

Enclosures:

September 10, 2018	ADEC Request for Additional Information for UAF BACT Analysis
May 21, 2018	EPA Comments on ADEC Preliminary Draft Serious SIP Development Materials for the Fairbanks Serious PM-2.5 nonattainment Area
March 22, 2018	UAF Comments Addressing the Preliminary Best Available Control Technology Determination for University of Alaska Fairbanks
October 20, 2017	Request for Additional Information for UAF BACT Analysis
May 11, 2017	Serious SIP BACT due date email
April 24, 2015	Voluntary BACT Analysis for UAF

cc: Larry Hartig, ADEC/ Commissioner's Office
Alice Edwards, ADEC/ Commissioner's Office
Cindy Heil, ADEC/Air Quality
Brittany Crutchfield, ADEC/Air Quality
Frances Isgrigg/University of Alaska Fairbanks
Dan Brown, EPA Region 10
Aaron Simpson, ADEC/Air Quality
Jim Plosay, ADEC/ Air Quality
Deanna Huff, ADEC/ Air Quality
Tim Hamlin, EPA Region 10
Zach Hedgpeth, EPA Region 10

ADEC Request for Additional Information
University of Alaska Fairbanks
BACT Technical Memorandum Review
SLR Report January 2017

September 10, 2018

Please address the following comments by providing the additional information identified by November 1, 2018. Following the receipt of the information the Alaska Department of Environmental Conservation (ADEC) intends to make its preliminary Best Available Control Technology (BACT) determination and release that determination for public comment. In order to provide this additional comment opportunity, ADEC must adhere to a strict schedule. Your assistance in providing the necessary information in a timely manner is greatly appreciated. Additional requests for information may result from comments received during the public comment period or based upon the new information provided in response to this information request.

This document does not represent a final BACT determination by ADEC. Please contact Aaron Simpson at aaron.simpson@alaska.gov with any questions regarding ADEC's comments.

Draft Comments

1. Equipment Life – Page 45 (Adobe page number) of the analysis[1] states "a standardized ten year return on investment at seven percent interest rate is assumed." This assumption for the equipment life is based solely on the statement that "because of the harsh climate, equipment in interior Alaska experiences more wear and tear than equipment in moderate climates." The 10 year equipment life assumption is based on the harsh climate, evidence of which must be provided. This evidence could include information regarding the actual age of currently operating control equipment, or design documents for associated process equipment such as boilers. A 20 year equipment life may be used for SNCR, but a 30 year equipment life is required for the other control devices (i.e., SCR, Wet FGD, DSI, circulating dry scrubber (CDS), and SDA) unless detailed documentation can be provided.

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3. CFB Boiler: Wet Scrubbing – Clearly explain the basis for excluding wet scrubbing in the BACT analysis.

4. CFB Boiler: SDA and DSI
    a. As part of their Oklahoma Best Available Retrofit Technology (BART) Federal Implementation Plan (FIP) final rule for regional haze[2], US EPA Region 6 found that a

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[1] University of Alaska Fairbanks, Voluntary Best Available Control Technology Analysis for the Serious $PM_{2.5}$ Non-Attainment Area Classification, Prepared by SLR, January 2017

[2] 76 FR 81728, December 28, 2011

reasonable estimate for equipment life is 30 years for SO_2 control technologies, please provide a detailed explanation for the equipment life listed for the SDA and DSI control technologies.

b. Please provide the documents for the following citations:
    i. "SCI engineering estimates (5 years old) for other SDAs."
    ii. "SCI engineering estimates (5 years old) for other DSI systems"
    iii. "Internal SDA cost study done by SCI in 2010, which indicated 8%."
    iv. "…similar internal SCI SDA cost analysis and other vendor (FTEK SCR) quotes."

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6. <u>CFB Boiler: SCR</u> – Please revise the cost analysis submitted using the EPA updated cost manual chapter pertaining to SCR[3]. Documentation must be provided for the following cited information:
    a. "Cost of startup spares indicated as a percentage of equipment cost per similar project."
    b. Fab Site Vendor "days based on similar project."
    c. Onsite Vendor "days based on similar project."
    d. Indirect capital costs "18% was used in similar SCR BACT analysis for smaller CTs."
    e. "Replacement labor based on similar project."
    f. "Labor cost based on similar project."

    The Department notes that records can be submitted to the Department under the provisions of the Alaska Statute dealing with confidentiality of records under AS 46.14.520.

7. <u>EU 3 Mid-Sized Diesel Boiler: SCR</u>
    a. Please provide the documentation for following citations in the BACT analysis.
        i. "Replacement labor based on similar project."
        ii. Transport cost direct to site (SCR catalyst). "Based on similar project."
        iii. Transport cost for spent SCR catalyst. "Based on similar project."
    b. No basis is provided for the SCR freight cost of $20,000.
    c. The budgetary nature of the costs provided by FuelTech (+/- 30%) is reflected in the nature of the cost effectiveness analysis methodology established in the EPA Cost Manual, provide justification for 30% contingency factor.

    The Department notes that records can be submitted to the Department under the provisions of the Alaska Statute dealing with confidentiality of records under AS 46.14.520.

8. <u>EU 8 Large Diesel Fired Engine: DPF and SCR</u> – The BACT analysis identifies back pressure as a potential technical challenge of installing a DPF to a large diesel engine such as EU 8, please provide a technical analysis basis for this statement.

9. <u>SO_2 Control Device: Circulating Dry Scrubber –</u> Please include CDS in the analysis for SO_2 emission controls. It is required that all control devices are evaluated for BACT.

10. <u>Control Technology Availability –</u> Documentation from multiple control technology vendors must be provided in order to eliminate a control technology based on unavailability. Please provide additional information regarding the lack of availability for control technologies

[3] https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution

eliminated on this basis. This additional information should not be provided from the EU's manufacturer.

11. Retrofitting – Please provide additional information regarding technologies eliminated due to space constraints and/or complications. Detailed information must be provided in support of eliminating a control technology based on space requirements. Additionally, documentation regarding any inclusion of retrofitting cost must be provided. Please provide site-specific quotes for retrofitting requirements.

UNIVERSITY OF ALASKA FAIRBANKS
www.uaf.edu/safety

ENVIRONMENTAL, HEALTH, SAFETY, and RISK MANAGEMENT
1855 Marika Road
PO Box 758145
Fairbanks, Alaska 99775-8145
(907) 474-5413
(907) 474-5489 fax

CERTIFIED MAIL: 7016 0910 0001 6126 2178
Return Receipt Requested

November 1, 2018

Denise Koch, Director
Division of Air Quality
Alaska Department of Environmental Conservation
410 Willoughby Avenue, Suite 303
PO Box 111800
Juneau, Alaska 99811-1800

Subject: University of Alaska Fairbanks
Response to the September 13, 2018 ADEC request for additional Information for the Best Available Control Technology Technical Memorandum

Dear Ms. Koch:

Attached is the response by the University of Alaska Fairbanks to your September 13, 2018 request for additional information for the Best Available Control Technology Technical Memorandum for University of Alaska Fairbanks (UAF).

If you have any questions related to this response, please feel free to contact me at fisgrigg@alaska.edu

Sincerely,

FOR

Frances M. Isgrigg, PE
Director, Environmental, Health, Safety and Risk Management
University of Alaska Fairbanks
1855 Marika Road
Fairbanks, Alaska 99775-8145
P: 907-474-5487 | F: 907-474-5489 | C: 907-590-5809

Enclosures:
September 13, 2018 ADEC Request for Additional Information on UAF BACT Analysis
November 1, 2018 UAF Response to September 13, 2018 ADEC Request letter

cc: (via email) Frances Isgrigg, UAF; Cindy Heil, ADEC/Air Quality; Deanna Huff, ADEC/Air Quality; Courtney Kimball, SLR; Russ Steiger, UAF

THE STATE of ALASKA
GOVERNOR BILL WALKER

Department of Environmental Conservation

DIVISION OF AIR QUALITY
Director's Office

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Toll Free: 866 241-2805
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CERTIFIED MAIL: 7017 3040 0000 4359 5202
Return Receipt Requested

September 13, 2018

Frances Isgrigg, Director
Environmental Health, Safety & Risk Management
University of Alaska Fairbanks
PO Box 758145
Fairbanks, AK 99775

Subject: Request for additional information for the Best Available Control Technology Technical Memorandum for University of Alaska Fairbanks by November 1, 2018

Dear Ms. Isgirgg:

A portion of the Fairbanks North Star Borough (FNSB) has been in nonattainment with the 24-hour National Ambient Air Quality Standard for fine particulate matter ($PM_{2.5}$) since 2009. In a letter dated April 24, 2015, I requested that the University of Alaska Fairbanks and other affected stationary sources voluntarily provide the Alaska Department of Environmental Conservation (ADEC) with a Best Available Control Technology (BACT) analysis in advance of the nonattainment area being reclassified to a Serious Area. On May 10, 2017, the US Environmental Protection Agency (EPA) published their determination that the FNSB $PM_{2.5}$ nonattainment area would be reclassified from a Moderate Area to a Serious Area effective June 9, 2017.[1]

Once the nonattainment area was reclassified to Serious, it triggered the need for Best Available Control Measure (BACM)/BACT analyses. A BACM analysis requires that ADEC review potential control measure options for the various sectors that contribute to the $PM_{2.5}$ air pollution in the nonattainment area. A BACT analysis must be conducted for applicable stationary sources such as the University of Alaska Fairbanks. BACM and BACT are required to be evaluated regardless of the level of contribution by the source to the problem or its impact on the areas ability to attain.[2] The BACT analysis is a required component of a Serious State Implementation Plan (SIP).[3] ADEC sent an email to Ms. Isgrigg on May 11, 2017 notifying her of the reclassification to Serious and included

[1] Federal Register, Vol. 82, No. 89, Wednesday May 10, 2017 (https://dec.alaska.gov/air/anpms/comm/docs/2017-09391-CFR.pdf)

[2] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf, Clean Air Act 189 (b)(1)(B) and 189 (e) and CFR 51.1010(4)(i) require the implementation of BACT for point sources and precursors emissions and BACM for area sources.

[3] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf, Clean Air Act 189 (b)(1)(B) and 189 (e) require the implementation of BACT for point sources and precursors emissions and BACM for area sources

a request for the BACT analysis to be completed by August 8, 2017. The BACT analysis was submitted by email to ADEC on February 8, 2017 from University of Alaska Fairbanks. It included emission units found in Operating Permit AQ0316TVP02 Revision 1 and Minor Permit AQ0316MSS06 Revision 2.

On March 22, 2018, ADEC released a preliminary draft of the BACT determination for the University of Alaska Fairbanks for public discussion on its website at: http://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-serious-sip-development. As indicated in the release, this document is a work in progress. ADEC received additional information from the University of Alaska Fairbanks and the EPA on the preliminary draft BACT determination and expects to make changes to the determination based upon this input. Therefore, ADEC is requesting additional information from the University of Alaska Fairbanks to assist it in making a legally and practicably enforceable BACT determination for the source.

Specifically, ADEC requests that the University of Alaska Fairbanks review the cost effectiveness spreadsheet provided as a part of the preliminary SO_2 BACT determination which was originally developed by Sargent & Lundy (S&L) in 2010. The spreadsheet includes a link to the S&L white paper that provides a basis for the cost effectiveness calculations and indicates that the model is intended to calculate estimated total project cost (total capital cost of installation), as well as direct and indirect annual operating costs. These calculations are largely based on the estimated usage of sorbent and the gross generating capacity of the plant. Please use this spreadsheet to calculate the cost effectiveness of SO_2 removal in dollars per ton and identify all assumptions and technical justifications used in the analysis.

If ADEC does not receive a response to this information request by November 1, 2018, ADEC will make a preliminary BACT determination based upon the information originally provided. However, ADEC does not have the in depth knowledge of your facility's infrastructure and without additional information, may select a more stringent BACT for your facility in order to be approvable by EPA. It is ADEC's intent to release the preliminary BACT determinations for public review along with any precursor demonstrations and BACM analyses before the required public comment process for the Serious SIP. In order to provide this additional comment opportunity, ADEC must adhere to a strict schedule. Your assistance in providing the necessary information in a timely manner is greatly appreciated.

After ADEC makes a final BACT determination for the University of Alaska Fairbanks, it must include the determination in Alaska's Serious SIP that then ultimately requires approval by EPA.[4] In addition, the BACT implementation 'clock' was also triggered by the EPA reclassification of the area to Serious on June 9, 2017. Therefore, the control measures that are included in the final BACT determination will be required to be fully implemented prior to June 9, 2021 - 4 years after reclassification.[5]

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Sincerely,

BY OR

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Division of Air Quality

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ADEC Request for Additional Information
University of Alaska Fairbanks
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ATTACHMENT 1

The University of Alaska Fairbanks (UAF) received a request for additional information regarding the Best Available Control Technology (BACT) analysis from the Alaska Department of Environmental Conservation (ADEC) on September 13, 2018. This request included a set of 11 draft comments and a request in the body of the letter pertaining to the sulfur dioxide (SO_2) BACT determination. The comments are repeated below, followed by the UAF response to each comment in italicized font.

1. Equipment Life – Page 45 (Adobe page number) of the analysis states "a standardized ten year return on investment at seven percent interest rate is assumed." This assumption for the equipment life is based solely on the statement that "because of the harsh climate, equipment in interior Alaska experiences more wear and tear than equipment in moderate climates." The 10 year equipment life assumption is based on the harsh climate, evidence of which must be provided. This evidence could include information regarding the actual age of currently operating control equipment, or design documents for associated process equipment such as boilers. A 20 year equipment life may be used for SNCR, but a 30 year equipment life is required for the other control devices (i.e., SCR, Wet FGD, DSI, circulating dry scrubber (CDS), and SDA) unless detailed documentation can be provided.

   UAF Response to Comment 1:
   Consistent with established ADEC practice and previously approved Prevention of Significant Deterioration (PSD) permitting BACT analyses, a 10-year equipment life was initially used in the calculation of the capital recovery factor for the UAF BACT analysis. This equipment life was subsequently increased to 15 years for the Emissions Unit (EU) 113 spray dryer absorber (SDA) and dry sorbent injection (DSI) BACT analyses. This 10- to 15-year equipment life timeframe is appropriate for equipment operated in the harsh Alaska climate. Two recent permits with BACT analyses based on a 10-year life are Permit No. AQ0237CPT04 (see footnote to Table B-4 of the Technical Analysis Report) and Permit No. AQ0083CPT06 (see page 24 of Technical Analysis Report). Please note that UAF addressed similar questions in the December 21, 2017 response to EPA Region 10 and ADEC comments on the UAF BACT analysis. The information presented here is in addition to the previously provided information.

   The EPA Air Pollution Control Cost Manual (sixth edition, EPA/452/B-02-001, Control Cost Manual) uses equipment lifetimes between five and 30 years. Ten, 15, and 20-year lifespans are frequently used in the manual. In the information request, ADEC states that using "a 30 year equipment life is required for the other control devices [i.e., SCR Wet FGD, DSI, circulating dry scrubber (CDS), and SDA] unless detailed documentation can be provided." UAF notes that the Control Cost Manual is a guidance document as opposed to being a regulation. UAF is not aware of a rule or rulemaking that requires the use of a specific equipment life. UAF requests that ADEC provide the regulatory citations that mandate the use of a 30-year equipment life.

   Using a 10-year equipment life timeframe is appropriate in this case because of the harsh Alaska climate. One aspect of this harsh climate is the extreme ambient temperature range that is experienced in Fairbanks. The recorded ambient temperature ranges from -66 degrees Fahrenheit

(°F) to 96 °F, a span of 162 °F. The mean ambient temperature is less than 32 °F from October to April. Another aspect of this harsh climate is the occurrence of wintertime temperature inversions and the subsequent formation of ice fog. Snowfall is also a factor in defining the harsh climate, with daily recorded snowfalls of up to 16 inches and monthly recorded snowfalls of up to 65 inches. Climate data for the Fairbanks area is provided in Attachment 2.

The result of this harsh climate is a shorter equipment life due to the stress placed on materials and operating systems. Practical experience in Interior Alaska has demonstrated that items exposed to these ambient conditions (such as exterior piping (even if insulated and/or buried), any equipment with moving parts, and exhaust stacks and vents) require more frequent routine maintenance, are prone to more frequent failure, and have a shorter useful life. The harsh climate also impacts equipment located within structures. For example, DSI sorbent (or any other material) that is delivered in winter would arrive at the outside ambient temperature. Bringing that cold material inside can result in detrimental temperature stress, condensation issues, or other impacts to the equipment that is otherwise not exposed to ambient conditions.

2. Interest Rate – Page 45 (Adobe page number) of the analysis states "a standardized ten year return on investment at seven percent interest rate is assumed." All cost analysis must use the current bank prime interest rate. This can be found online at; https://www.federalreserve.gov/releases/h15/ (go to bank prime rate in the table). Please revise the cost analyses as appropriate.

   UAF Response to Comment 2:
   UAF notes that the Control Cost Manual is a guidance document, not a regulation. Chapter 2 of the Control Cost Manual (updated February 1, 2018) addresses the importance of using "appropriate private nominal interest rates." Use of the bank prime rate is presented as an option if firm-specific nominal interest rates cannot be estimated or verified. UAF does not currently have sufficient information about potential interest rates to enable the selection of a specific interest rate for a UAF project. While UAF does not necessarily agree that the bank prime rate is the most appropriate rate, the cost analyses have been revised to reflect the current bank prime interest rate of 5.25 percent per year. UAF obtained the rate of 5.25 percent from the H.15 release (October 23, 2018) on the Federal Reserve website (https://www.federalreserve.gov/releases/h15/). The table below provides the resulting cost effectiveness values in terms of dollar per ton of pollutant avoided.

Applicable Table in UAF Voluntary BACT Analysis	*Emissions Unit*	*Control Device*	*Project Life*	*Cost Effectiveness ($ per ton avoided) at 5.25% interest*
3-5	*113*	*SCR*	*10[a]*	*$27,013*
			20[a]	*$20,673*
3-7	*113*	*SNCR*	*10*	*$9,547*
3-9	*3*	*SCR*	*10*	*$8,086*
3-11	*3*	*LNB/FGR*	*10*	*$3,396*
3-13	*4*	*LNB/FGR*	*10*	*$176,906*
3-15	*8*	*SCR*	*10*	*$26,244*
3-17	*27*	*SCR*	*10*	*$11,985*
4-5	*19, 20, 21*	*PM Scrubber*	*10*	*$44,135*
4-7	*27*	*DPF*	*10*	*$18,239*
4-9	*9A*	*Fabric Filter*	*10*	*$709,916*
5-5	*113*	*SDA*	*10[b]*	*$12,992*
			15[b]	*$10,824*
5-7	*113*	*DSI*	*10[b]*	*$8,464*
			15[b]	*$8,032*
5-8	*3*	*ULSD*	*N/A*	*$1,084*
5-9	*4*	*ULSD*	*N/A*	*$1,082*
5-10	*8*	*ULSD*	*N/A*	*$971*
N/A	*27*	*SCR/DPF combination[c]*	*10*	*$10,990*

Notes:

[a] A 10-year life was used in the BACT analysis that UAF provided to ADEC in January 2017. Costs based on a 20-year life were provided in the December 2017 UAF response to an ADEC information request.
[b] A 10-year life was used in the BACT analysis that UAF provided to ADEC in January 2017. Costs based on a 15-year life were provided in the December 2017 UAF response to an ADEC information request.
[c] This technology was not addressed in the BACT analysis that UAF provided to ADEC in January 2017. The cost for combined SCR and DPF for EU 27 was provided in the December 2017 UAF response to an ADEC information request.

3. CFB Boiler: Wet Scrubbing – Clearly explain the basis for excluding wet scrubbing in the BACT analysis.

   UAF Response to Comment 3:
   Please note that UAF addressed a similar question in the December 21, 2017 response to EPA Region 10 and ADEC comments on the UAF BACT analysis. The information presented here is in addition to the previously provided information.

   Wet scrubbing is an older technology that has been in existence for approximately 100 years.

Wet scrubbers are expensive, difficult to maintain, require a large footprint, and require high water consumption. Pulverized coal boilers have been equipped with wet scrubbers as post-combustion SO_2 emission controls. Wet scrubbing was not included in the UAF BACT analysis because the UAF boiler is not a pulverized coal boiler. The UAF boiler EU 113 is a circulating fluidized bed (CFB) boiler. The CFB boiler design is a relatively new technology that has been developed and operated in the past few decades. The CFB boiler design is unique in that the scrubbing SO_2 control technology is not post-combustion, but is an integral part of the boiler design. The CFB boiler includes a limestone injection system. The coal is mixed with the limestone to absorb SO_2 emissions as the combustion air passes through the bed.

Wet scrubbing has not been demonstrated in practice for CFB boilers. Because the BACT analysis cannot redefine the source, such as switching a CFB boiler to a pulverized coal boiler, wet scrubbing is not an appropriate technology and was not examined in the UAF SO_2 BACT analysis.

4. <u>CFB Boiler: SDA and DSI</u>
    a. As part of their Oklahoma Best Available Retrofit Technology (BART) Federal Implementation Plan (FIP) final rule for regional haze, US EPA Region 6 found that a reasonable estimate for equipment life is 30 years for SO_2 control technologies, please provide a detailed explanation for the equipment life listed for the SDA and DSI control technologies.

    <u>UAF response to Comment 4a:</u>
    For the reasons discussed in the response to ADEC Comment 1 and provided below, UAF continues to believe that using a 30-year equipment life is not appropriate for SDA and DSI emission control systems as applied to EU 113. As a courtesy, UAF previously re-calculated the cost analysis for SDA and DSI as applied to EU 113 using a 15-year equipment life instead of the 10-year equipment used in the initial BACT analysis provided to ADEC. These recalculated cost effectiveness values were provided to ADEC on December 21, 2017. For SDA, the cost effectiveness would be $11,598 per ton of SO_2 emissions avoided. For DSI, the cost effectiveness would be $8,186 per ton of SO_2 emissions avoided. (Please see the response to ADEC Comment 2 for the cost effectiveness values calculated using the current bank prime interest rate.)

    ADEC cited a proposed federal rulemaking addressing a regional haze determination from EPA Region 6 to support a 30-year equipment life for SDA and DSI. The preamble to that proposed rule includes a discussion of equipment life for SO_2 scrubbers. The preamble states that a prior Oklahoma Federal Implementation Plan (FIP) used a lifetime of 30 years to determine costs for SO_2 scrubbers. As explained in the response to Comment 1, expanding the use of the Oklahoma FIP 30-year equipment life to the EU 113 is not appropriate because the suitability and design of equipment installed in Oklahoma is not the same as the suitability and design of equipment that would be installed in Interior Alaska. This conclusion is consistent with the basic premise that each BACT determination is to be made on a case-by-case basis. Please note that UAF addressed similar questions in the December 21, 2017 response to EPA Region 10 and ADEC *comments on the UAF BACT analysis. The information presented here is in addition to the previously provided information.*

As a point of clarification, the Control Cost Manual does not indicate the use of a 30-year equipment life for any SO_2 emission control systems. Instead, the Control Cost Manual, Section 5.2, Chapter 1, paragraph 1.5.2, provides a 15-year equipment life for a wet scrubber, and cites Section 1 of the manual regarding capital recovery costs. The EPA Region 6 use of a 30-year life for SO_2 scrubbers is not consistent with the Control Cost Manual.

A 30-year equipment life for SDA and DSI as applied to EU 113 is inconsistent with EPA long-standing guidance regarding equipment life determinations. The 1990 New Source Review Workshop Manual for Prevention of Significant Deterioration and Nonattainment Area Permitting states on page b.10 of Appendix B that "The economic life of a control system typically varies between 10 to 20 years and longer ***and*** *should be determined consistent with data from EPA cost support documents and the IRS Class Life Asset Depreciation Range System." (Emphasis added.) EU 113 will be a co-generation boiler that will produce steam for campus heat and steam for the generation of electricity. Table B-1 of IRS Publication 946 (2016) provides a class life, or a tax cost recovery period, of 22 years for assets associated with Industrial Steam and Electric Generation and/or Distribution Systems (see Asset Class 00.4). Based on this information, a 30-year equipment life is not consistent with the EPA policy that the economic life of an emission control system should also be consistent with the IRS Class Life Asset Depreciation Range System.*

The conclusion is that the EPA Region 6 decision is not a mandate to base all future SDA and DSI BACT analyses on a 30-year equipment lifespan because:

- *BACT is determined on a case-by-case basis that incorporates site specific conditions;*
- *The EPA Control Cost Manual does not support a 30-year equipment for SDA and DSI; and*
- *EPA Prevention of Significant Deterioration (PSD) and Non-attainment New Source Review (NA-NSR) guidance does not support a 30-year equipment for SDA and DSI.*

b. Please provide the documents for the following citations:
   i. "SCI engineering estimates (5 years old) for other SDAs."

   UAF response to Comment 4b(i):
   These estimates were based on a Boiler MACT compliance feasibility study prepared by UAF's consultant, Stanley Consultants, Inc. (SCI), for a separate, confidential client. Because the client is not UAF and is confidential, SCI is not able to provide the estimate to UAF. This documentation is client confidential and cannot be provided to UAF or the agency. UAF is not able to submit the

document under the confidential business information (CBI) provisions because the underlying estimate is not available to UAF. For the purposes of a study-level cost estimate for a BACT analysis, UAF believes that use of the engineering estimate is appropriate and further documentation is not necessary.

ii. "SCI engineering estimates (5 years old) for other DSI systems"

<u>UAF response to Comment 4b(ii):</u>
These estimates were based on a Boiler MACT compliance feasibility study prepared by UAF's consultant, SCI, for a separate, confidential client. Because the client is not UAF and is confidential, SCI is not able to provide the estimate to UAF. This documentation is client confidential and cannot be provided to UAF or the agency. UAF is not able to submit the document under the CBI provisions because the underlying estimate is not available to UAF. For the purposes of a study-level cost estimate for a BACT analysis, UAF believes that use of the engineering estimate is appropriate and further documentation is not necessary.

iii. "Internal SDA cost study done by SCI in 2010, which indicated 8%."

<u>UAF response to Comment 4b(iii):</u>
These estimates were based on a Boiler MACT compliance feasibility study prepared by UAF's consultant, SCI, for a separate, confidential client. Because the client is not UAF and is confidential, SCI is not able to provide the estimate to UAF This documentation is client confidential and cannot be provided to UAF or the agency. UAF is not able to submit the document under the CBI provisions because the underlying estimate is not available to UAF. For the purposes of a study-level cost estimate for a BACT analysis, UAF believes that use of the engineering estimate is appropriate and further documentation is not necessary.

iv. "...similar internal SCI SDA cost analysis and other vendor (FTEK SCR) quotes."

<u>UAF response to Comment 4b(iv):</u>
These estimates were based on a Boiler MACT compliance feasibility study prepared by UAF's consultant, SCI, for a separate, confidential client. Because the client is not UAF and is confidential, SCI is not able to provide the estimate to UAF This documentation is client confidential and cannot be provided to UAF or the agency. UAF is not able to submit the document under the CBI provisions because the underlying estimate is not available to UAF. For the purposes of a study-level cost estimate for a BACT analysis, UAF believes that use of the engineering estimate is appropriate and further documentation is not necessary.

The FTEK SCR quote was provided in Appendix B of the BACT analysis report.

5. <u>CFB Boiler: SNCR</u> – Please provide documentation for the following citation in the BACT

analysis: Indirect capital costs "18% was used in similar SCR BACT analysis. Assume same amount for SNCR."

<u>UAF Response to Comment 5:</u>
Per the EPA Control Cost Manual, Section 4 (NO_X Controls) Table 1.4: Capital Cost Factors for an SNCR Application (effective at the time of the UAF BACT Analysis), the indirect capital cost is listed as 20 percent of the direct capital cost (DCC). Specifically, Table 2.5 lists general facilities as 5 percent of the DCC, engineering and home office fees as 10 percent of the DCC, and process contingency as 5 percent of the DCC, for a total of 20 percent. Please note that UAF addressed similar questions in the December 21, 2017 response to EPA Region 10 and ADEC comments on the UAF BACT analysis. The information presented here is in addition to the previously provided information.

UAF was conservative in the EU 113 SNCR cost analysis, using indirect capital costs as 18 percent of the direct capital costs. This ratio is consistent with the ExxonMobil Point Thomson Production Facility BACT analysis for SCR systems on combustion turbines, which used vendor data for indirect capital costs and not the EPA Control Cost Manual capital cost factors. For the purposes of a study-level cost estimate for a BACT analysis, UAF believes that the use of a recent ADEC-approved estimate ratio for determining indirect costs is sufficient, and that further documentation is not necessary.

6. <u>CFB Boiler: SCR</u> – Please revise the cost analysis submitted using the EPA updated cost manual chapter pertaining to SCR. Documentation must be provided for the following cited information:
    a. "Cost of startup spares indicated as a percentage of equipment cost per similar project."

    <u>UAF Response to Comment 6a:</u>
    The cost of startup spares was estimated as a percentage of equipment cost in a similar project. The UAF consultant has indicated that the project was prepared for a confidential client. This documentation is client confidential and cannot be provided to UAF or the agency. UAF is not able to submit the document under the CBI provisions because the underlying estimate is not available to UAF. For the purposes of a study-level cost estimate for a BACT analysis, UAF believes that the cost for startup spare equipment estimated at 0.50 percent of total equipment costs is reasonable, and that further documentation is not necessary.

    b. Fab Site Vendor "days based on similar project".

    <u>UAF Response to Comment 6b:</u>
    The fabrication site vendor representative fees were assumed to be comparable to those fees from a similar project. The UAF consultant has indicated that the project was prepared for a confidential client. This documentation is client confidential and cannot be provided to UAF or the agency. UAF is not able to submit the document under the CBI

provisions because the underlying estimate is not available to UAF. For the purposes of a study-level cost estimate for a BACT analysis, UAF believes that these vendor fees are reasonable, and that further documentation is not necessary.

c. Onsite Vendor "days based on similar project".

UAF Response to Comment 6c:
The onsite vendor representative fees were assumed to be comparable to those fees from a similar project. The UAF consultant has indicated that the project was prepared for a confidential client. This documentation is client confidential and cannot be provided to UAF or the agency. UAF is not able to submit the document under the CBI provisions because the underlying estimate is not available to UAF. For the purposes of a study-level cost estimate for a BACT analysis, UAF believes that these vendor fees are reasonable, and that further documentation is not necessary.

d. Indirect capital costs "18% was used in similar SCR BACT analysis for smaller CTs."

UAF Response to Comment 6d:
Per the EPA Control Cost Manual, Section 4 (NO_X Controls) Table 1.4: Capital Cost Factors for an SNCR Application (effective at the time of the UAF BACT Analysis), the indirect capital cost is listed as 20 percent of the DCC. Specifically, Table 2.5 lists general facilities as 5 percent of the DCC, engineering and home office fees as 10 percent of the DCC, and process contingency as 5 percent of the DCC, for a total of 20 percent. Please note that UAF addressed similar questions in the December 21, 2017 response to EPA Region 10 and ADEC comments on the UAF BACT analysis. The information presented here is in addition to the previously provided information.

UAF was conservative in the EU 113 SCR cost analysis, using indirect capital costs as 18 percent of the direct capital costs. This ratio is consistent with the ExxonMobil Point Thomson Production Facility BACT analysis for SCR systems on combustion turbines, which used vendor data for indirect capital costs and not the EPA Control Cost Manual capital cost factors. For the purposes of a study-level cost estimate for a BACT analysis, UAF believes that the use of a recent ADEC-approved estimate ratio for determining indirect costs is sufficient, and that further documentation is not necessary.

e. "Replacement labor based on similar project."

UAF Response to Comment 6e:
The catalyst replacement labor hours were assumed to be comparable to those labor hours determined in a similar project. The UAF consultant has indicated that the project was prepared for a confidential client. This documentation is client confidential and cannot be provided to UAF or the agency. UAF is not able to submit the document under the CBI provisions because the underlying estimate is not available to UAF. For the purposes of a study-level cost estimate for a BACT analysis, UAF believes that the labor

hour estimate is appropriate, and that further documentation is not necessary.

f. "Labor cost based on similar project."

<u>*UAF Response to Comment 6f:*</u>
The catalyst replacement labor rate was assumed to be comparable to the catalyst replacement labor rate determined in a similar project. The UAF consultant has indicated that the project was prepared for a confidential client. This documentation is client confidential and cannot be provided to UAF or the agency. UAF is not able to submit the document under the CBI provisions because the underlying estimate is not available to UAF. The labor rate used in the analysis is likely conservatively low because the cost is not reflective of 2018 labor rates. For the purposes of a study-level cost estimate for a BACT analysis, UAF believes the rate is representative of labor costs, and that further documentation is not necessary.

7. <u>EU 3 Mid-Sized Diesel Boiler: SCR</u>
   a. Please provide the documentation for following citations in the BACT analysis.
      i. "Replacement labor based on similar project."

      <u>*UAF Response to Comment 7a(i):*</u>
      The catalyst replacement manhours and labor rate were assumed to be comparable to the manhours determined in a similar project. The UAF consultant has indicated that the project was prepared for a confidential client. This documentation is client confidential and cannot be provided to UAF or the agency. UAF is not able to submit the document under the CBI provisions because the underlying estimate is not available to UAF. For the purposes of a study-level cost estimate for a BACT analysis, UAF believes that the labor hour cost estimate for catalyst replacement is appropriate, and that further documentation is not necessary.

      ii. Transport cost direct to site (SCR catalyst). "Based on similar project."

      <u>*UAF Response to Comment 7a(ii):*</u>
      The catalyst transportation cost was assumed to be comparable to transport costs determined in a similar project. The UAF consultant has indicated that the project was prepared for a confidential client. This documentation is client confidential and cannot be provided to UAF or the agency. UAF is not able to submit the document under the CBI provisions because the underlying estimate is not available to UAF. For the purposes of a study-level cost estimate for a BACT analysis, UAF believes that the catalyst transport cost estimate is appropriate, and that further documentation is not necessary.

      iii. Transport cost for spent SCR catalyst. "Based on similar project."

UAF Response to Comment 7a(iii):

The transportation cost for the spent catalyst is assumed to be the same as the transportation cost for a replacement catalyst to UAF. Transportation costs are not typically dependent on the direction of travel. As a result, the analysis assumes that the cost of shipping the catalyst from the vendor to UAF will be the same as the cost of shipping the spent catalyst from UAF to the vendor.

b. No basis is provided for the SCR freight cost of $20,000.

UAF Response to Comment 7b:

UAF addressed a similar question in the December 21, 2017 response to EPA Region 10 and ADEC comments on the UAF BACT analysis. The information presented here is in addition to the previously provided information.

The $20,000 freight cost was based on the cost of freight for a smaller SCR application on the ACEP Generator Engine, EU 27. Please refer to the email from Erick Pomrenke at NC Power Systems to Lain Pacini on November 12, 2015 in Appendix B of the BACT analysis report. NC Power Systems stated that freight costs would be in the range of $9,000 to $12,000. The BACT analysis for EU 3 assumes that the SCR system for a larger emissions unit would weigh more and consequently have higher freight costs for shipment. The freight cost for an SCR system on EU 3 has been scaled up from the cost provided by NC Power Systems.

UAF believes that the estimated $20,000 freight cost is reasonable for purposes of this study-level cost analysis. UAF notes that deleting the freight cost from the analysis would result in a cost-effectiveness value that differs by less than $100 per ton of air pollutant removed. In other words, removing the freight cost from the analysis would alter the result of the analysis by less than one percent.

c. The budgetary nature of the costs provided by FuelTech (+/- 30%) is reflected in the nature of the cost effectiveness analysis methodology established in the EPA Cost Manual, provide justification for 30% contingency factor.

UAF Response to Comment 7c:

The Fuel Tech cost estimate was provided for budgetary purposes and without Fuel Tech conducting an on-site inspection. Due to the nature of the cost estimate, Fuel Tech included an accuracy range for the cost estimate. This range was +/- 20 percent for equipment capital costs and +/- 30 percent for installation costs. The Fuel Tech cost estimate values used in the BACT analysis were as quoted and did not include any additional markup or changes. In other words, the Fuel Tech cost estimate values as used in the BACT analysis were not adjusted to incorporate the cost estimate accuracy range. Please note that UAF addressed similar questions in the December 21, 2017 response to EPA Region 10 and ADEC comments on the UAF BACT analysis. The information presented here is in addition to the previously provided information.

Consistent with the EPA Control Cost Manual, a 30 percent contingency factor was applied in calculating the total capital investment. Because the cost estimate accuracy range was not included in the BACT analysis, only a single 30 percent contingency factor was used in the BACT analysis.

8. <u>EU 8 Large Diesel Fired Engine: DPF and SCR</u> – The BACT analysis identifies back pressure as a potential technical challenge of installing a DPF to a large diesel engine such as EU 8, please provide a technical analysis basis for this statement.

   <u>UAF Response to Comment 8:</u>
   UAF addressed a similar question in the December 21, 2017 response to EPA Region 10 and ADEC comments on the UAF BACT analysis. The information presented here is in addition to the previously provided information.

   Engine exhaust back pressure is the exhaust gas pressure that is provided by the engine to overcome the resistance of the exhaust system in order to discharge the exhaust into the atmosphere. Installing a diesel particulate filter (DPF) increases the exhaust back pressure. To compensate for the increase in back pressure, the engine must compress the exhaust gases to a higher pressure which involves additional mechanical work. Maximum allowable engine exhaust back pressure is inversely related to engine size. The larger the engine is, the lower the allowable exhaust back pressure can be.

   Because of the very large engine capacity of EU 8, (13,266 hp), the back pressure allowed by the engine manufacturer is very low. The reason for limiting the allowable back pressure in large engines is caused by the technical challenges that result from increased back pressure. These challenges include additional mechanical work and/or less energy extracted by the exhaust system which can adversely affect intake manifold boost pressure, an increase in fuel consumption, an increase in NOx, PM, and CO emissions, and the overheating of exhaust valves.

   DPFs are not commercially available for large capacity engines because the back pressure that would be created as a result of installing a DPF would exceed the maximum allowable back pressure specified by the engine manufacturer. Exceeding the maximum allowable back pressure would not allow the engine to operate as manufactured.

9. <u>SO_2 Control Device: Circulating Dry Scrubber</u> – Please include CDS in the analysis for SO_2 emission controls. It is required that all control devices are evaluated for BACT.

   <u>UAF Response to Comment 9:</u>
   The CFB boiler design includes integrated dry scrubbing control technology. The CFB boiler incorporates dry scrubbing technology by way of the limestone injection system that is inherent to the CFB design. The RACT/BACT/LAER Clearinghouse (RBLC) database does not list any applications of CDS used with CFB boilers. The RBLC lists only one industrial coal-fired boiler which uses CDS. That boiler is a pulverized coal (PC) boiler with a capacity of approximately 20

times larger than EU 113. As a result, CDS is not demonstrated in practice for CFB boilers and does not meet the criteria of an available control technology. Developing a detailed analysis to support this conclusion is not necessary.

With respect to the other boilers at UAF (EUs 3, 4, and 19 through 21), it is inherently obvious that firing ultra-low sulfur diesel (ULSD) fuel would reduce SO_2 emissions to a greater extent and would be significantly less expensive than adding post-combustion controls.

10. <u>Control Technology Availability</u> – Documentation from multiple control technology vendors must be provided in order to eliminate a control technology based on unavailability. Please provide additional information regarding the lack of availability for control technologies eliminated on this basis. This additional information should not be provided from the EU's manufacturer.

    <u>UAF Response to Comment 10:</u>
    Providing the requested documentation is not necessary because the unavailability of the cited emission control technologies is well established through databases such as the RACT/BACT/LAER Clearinghouse. Obtaining negative declarations of equipment availability from control technology vendors is not necessary because the UAF emissions unit manufacturers and engineers are experts who are well-versed in the available emission control technologies. As a result, UAF believes that the previously provided rationale, including any information from emissions unit manufacturers, is adequate to support the determinations that certain emission control technologies are unavailable.

11. <u>Retrofitting</u> – Please provide additional information regarding technologies eliminated due to space constraints and/or complications. Detailed information must be provided in support of eliminating a control technology based on space requirements. Additionally, documentation regarding any inclusion of retrofitting cost must be provided. Please provide site-specific quotes for retrofitting requirements.

    <u>UAF Response to Comment 11:</u>
    The recent construction of EU 113, including the building that houses that emissions unit, has expanded the footprint of the UAF power plant. The result of this larger footprint is that no space remains at the power plant site for a new building to house a selective catalytic reduction (SCR) system or any other new emission control systems at grade level. Please refer to the site plan drawings in Attachment 3. This lack of available space is self-evident based on visual inspection of the site and good engineering judgement. Developing detailed information and a detailed analysis is not needed to support this common sense conclusion.

    Because of the space constraints, retrofitting requirements and costs cannot be easily defined or developed. As noted above, no space exists for installing new emissions control systems at grade. The lack of available space to accommodate emission control equipment affects not only EU 113, but EU 4 as well. Plan drawings of the building enclosing EU 4 are provided in Attachment 4. The drawings demonstrate that the building enclosure does not provide sufficient space to add an

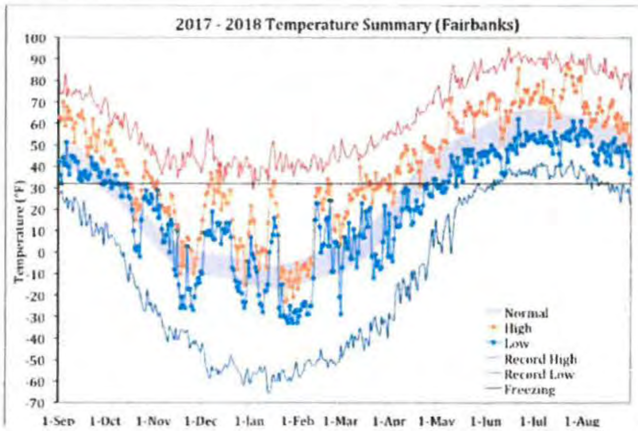
SCR control system for EU 4, as discussed in the BACT analysis UAF submitted in January 2017. Common sense dictates that installing retrofitted equipment on existing roofs or above existing structures is prohibitively expensive because the existing structures are not designed to bear the additional weight and provide safe access to the new equipment. As a result, any retrofit design would involve prohibitively expensive modification and/or reconstruction of existing structures.

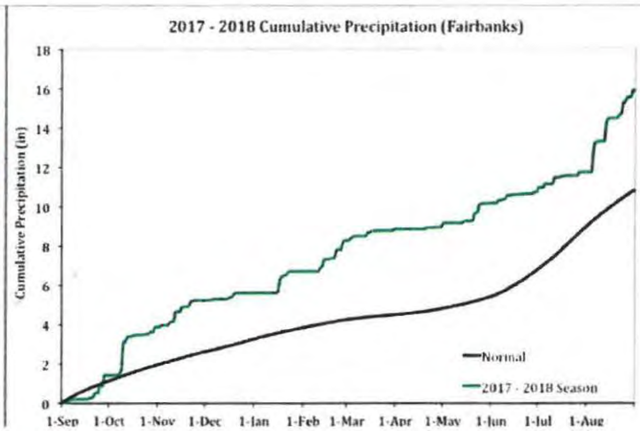
12. Request in ADEC letter dated September 13, 2018 - Specifically, ADEC requests that the University of Alaska Fairbanks review the cost effectiveness spreadsheet provided as a part of the preliminary SO_2 BACT determination which was originally developed by Sargent & Lundy (S&L) in 2010. The spreadsheet includes a link to the S&L white paper that provides a basis for the cost effectiveness calculations and indicates that the model is intended to calculate estimated total project cost (total capital cost of installation), as well as direct and indirect annual operating costs. These calculations are largely based on the estimated usage of sorbent and the gross generating capacity of the plant. Please use this spreadsheet to calculate the cost effectiveness of SO_2 removal in dollars per ton and identify all assumptions and technical justifications used in the analysis.

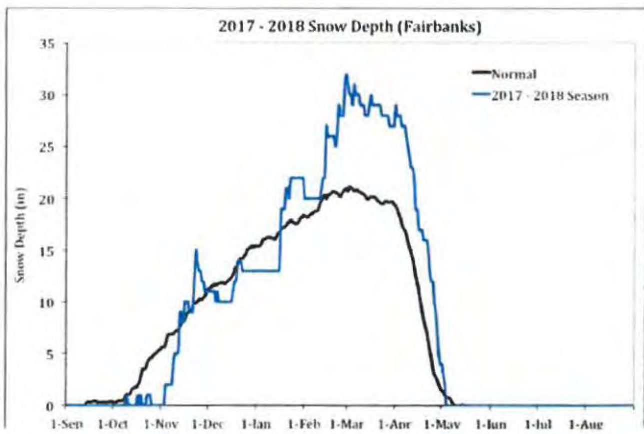
    UAF Response to Comment 12:
    UAF is not able to review the Sargent and Lundy (S&L) cost effectiveness spreadsheet and calculations as ADEC has requested because ADEC did not provide the S&L cost effectiveness spreadsheet to UAF for review. In May 2018, UAF submitted comments to ADEC addressing the preliminary BACT determination. Those comments included a discussion indicating that Step 4 of the preliminary SO_2 BACT determination for EU 113 did not include an economic analysis. As a result, UAF was not able to determine the methodology ADEC used to calculate the cost-effectiveness for the SO_2 emission control technologies and so was not able to provide further comment at that time. At this time, UAF does not have enough information to determine whether the S&L cost model is appropriate for any emissions units at UAF, or whether the cost model is appropriate for boilers at a heat and power plant.

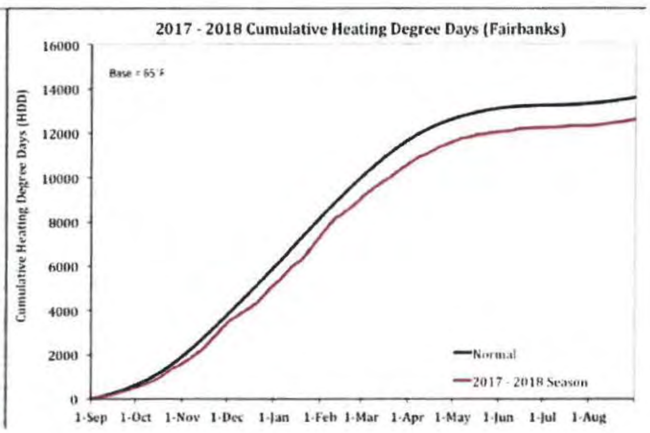
ATTACHMENT 2

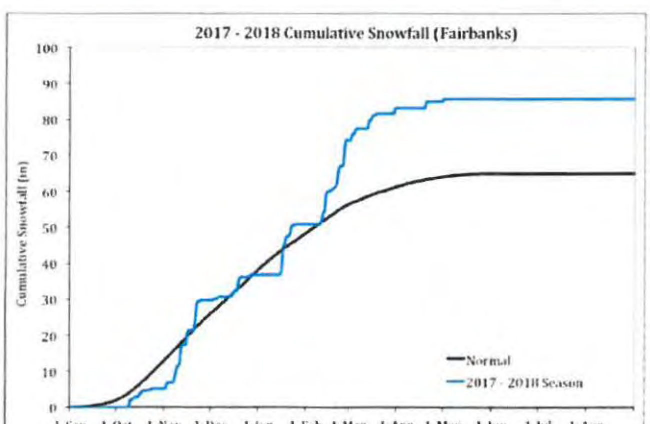
Fairbanks AP











Normal	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Mean Minimum	-16.9	-12.7	-2.5	20.6	37.8	49.3	52.3	46.4	35.1	16.5	-5.7	-12.9
Mean	-7.9	-1.3	11.4	32.5	49.4	60.4	62.5	56.1	44.9	24.2	2.6	-4.1
Mean Maximimum	1.1	10.0	25.4	44.5	61.0	71.6	72.7	65.9	54.6	31.9	10.9	4.8
Mean Precipitation	0.58	0.42	0.25	0.31	0.60	1.37	2.16	1.88	1.10	0.83	0.67	0.64
Snowfall	10.3	8.1	4.9	2.9	0.9	0.0	0.0	0.0	1.8	10.8	13.2	12.1
CDD	0	0	0	0	1	23	31	6	0	0	0	0
HDD	2260	1858	1660	974	485	160	108	281	605	1265	1872	2141

Temperature Extremes	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Highest Daily Maximum (°F)	52	50	56	76	90	96	94	93	84	72	54	58
Year	2009	1943	1994	2009	1947	1969	1975	1994	1957	2003	1936	1934
Lowest Daily Minimum (°F)	-66	-58	-49	-32	-1	29	34	23	3	-28	-46	-62
Year	1934	1947	1956	1944	1964	2006	1934	1947	1992	1935	1990	1961
Highest Mean (°F)	18.1	15.93	27.08	43.67	55.58	66.85	68.37	62.56	52.75	37.81	20.13	7.65
Year	1981	1980	1981	1940	2005	2004	1975	1977	1995	1938	1979	1985
Lowest Mean (°F)	-31.68	-25.27	-6.65	17.95	38.61	51.63	55.5	49.77	31.65	13.19	-10.5	-28.15
Year	1971	1979	1959	2013	1964	1949	1959	1969	1992	1996	1963	1956

Precipitation Extremes	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Highest 1-Day Maximum Precipitation (in)	1.33	0.86	0.87	0.92	0.78	1.38	2.27	3.42	1.21	1.17	0.91	0.94
Year	1937	1966	1963	2002	1992	1955	2003	1967	1954	1946	1935	1990
Highest Total Precipitation (in)	6.71	2.1	2.1	3.06	1.96	3.55	5.96	6.88	3.05	3.4	3.32	3.23
Year	1937	1944	1963	2002	2004	1949	2003	1930	1960	1935	1970	1984
Lowest Total Precipitation (in)	0.01	0.01	0.02	0.01	0.04	0.19	0.06	0.24	0.12	0.08	0.05	0.04
Year	1966	1976	2003	1944	2011	1966	2009	2005	1949	1954	2002	1952

Snow Extremes	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Highest 1-Day Maximum Snow (in)	15.5	16	12.6	10.8	9.4	1.2	0	0.1	7.8	12.5	14.6	12.9
Year	1937	1966	1963	1948	1992	1931	1930	1995	1992	1946	1970	1965
Highest Total Snow (in)	65.6	43.1	30.4	25.1	14.1	1.2	0	0.1	24.4	26.2	54	50.7
Year	1937	1966	1991	1948	1992	1931	1930	1995	1992	1935	1970	1984
Lowest Total Snow (in)	0.7	0.2	0.1	0.1	0	0	0	0	0	0.7	0.2	0.4
Year	1966	2000	1968	1954	1936	1930	1930	1930	1934	2013	1953	1952

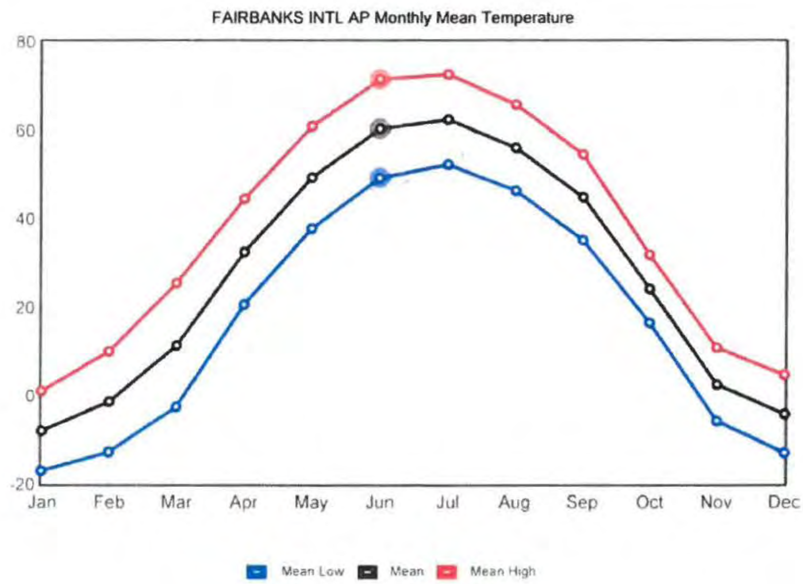
P.O Box 757320 Fairbanks, Alaska 99775-7320

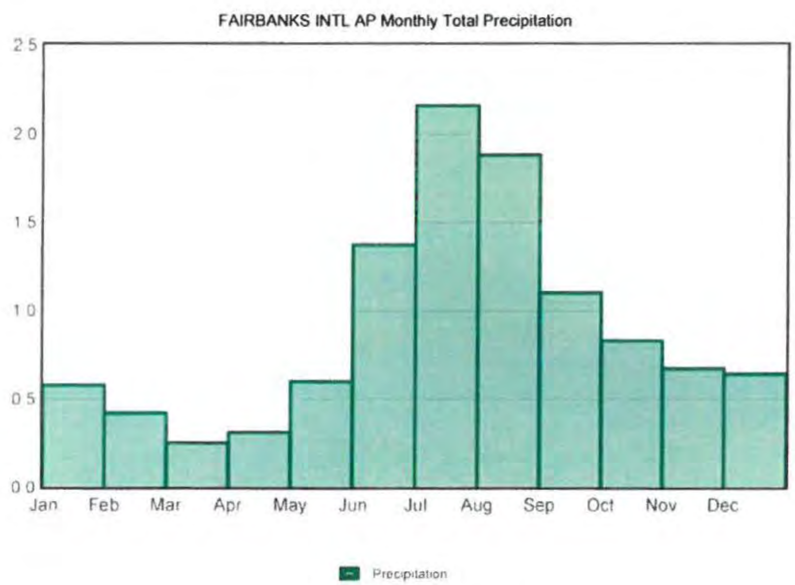
A Recognized State Climate Office - American Association of State Climatologists

Alaska Climographs

These are the mean monthly maximum and minimum temperature and total precipitation for the period 1981 - 2010 for the first order stations in Alaska using the climatic normals provided by the National Climatic Data Center. The normals products you'll find here represent average conditions over the most recent climate normal period (1981 - 2010).

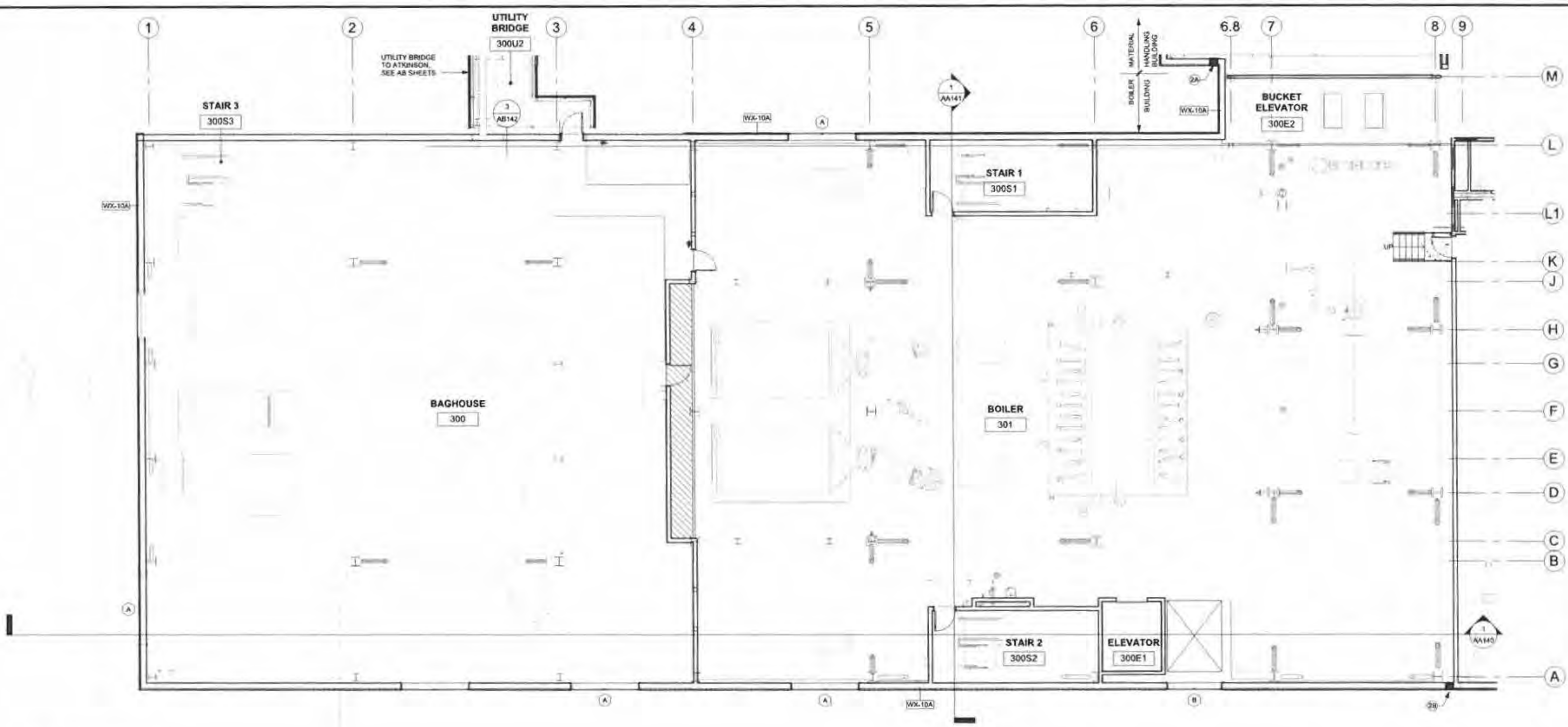
FAIRBANKS INTL AP





P.O Box 757320 Fairbanks, Alaska 99775-7320

ATTACHMENT 3



1 AA103 ENVELOPE PLAN - BOILER THIRD FLOOR (472'-2")
1/8" = 1'-0"

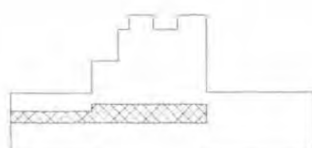
FLOOR PLAN NOTES

1. AA100 SHEET SERIES ARE FOR EXTERIOR/ ENVELOPE SCOPE OF WORK ONLY. BUILDING INTERIOR WORK SHOWN FOR GRAPHIC REPRESENTATION ONLY AND ARE DETAILED IN AA200 SHEET SERIES.
2. SEE AA140 FOR EXTERIOR ENVELOPE (WALL AND ROOF) ASSEMBLY TYPES.
3. SEE SA GIRT LAYOUT SHEETS FOR DIMENSIONAL LOCATIONS OF WINDOWS, DOORS, AND LOUVERS.

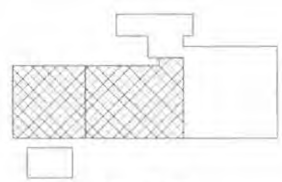
KEYNOTES

2A SEISMIC JOINT, SEE 7/AA146

2B SEISMIC JOINT, SEE 1/AA149



KEYPLAN - SECTION VIEW



KEYPLAN - PLAN VIEW

DRAWINGS ARE FOR EXTERIOR CONSTRUCTION.

INTERIOR FEATURES ARE FOR REFERENCE ONLY

AT FULL SIZE
0 1 2 3 IN
0 1 2 3 4 5 6 7 8cm

NO.	REVISIONS	DSGN	CHKD	APVD	DATE

Design Alaska
601 College Road Fairbanks AK 99701
www.designalaska.com

UNIVERSITY OF ALASKA FAIRBANKS
COMBINED HEAT AND POWER PLANT REPLACEMENT
FAIRBANKS, ALASKA; PROJECT NO. 2012031 CPHR

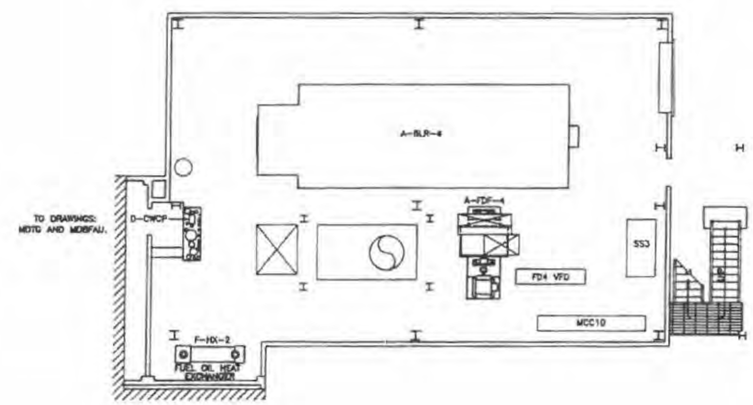
ENVELOPE PLAN - BOILER THIRD FLOOR (472'-2")

DESIGNED WCP
DRAWN ENS
CHECKED WCP
APPROVED KWP
APPROVED CHM
DATE APRIL 27, 2016

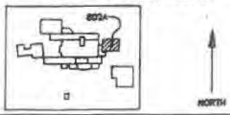
SCALE: As indicated
NO. 191401
AA103
REV. 0

4/27/2016 12:50:31 PM C:\Users\...\Documents\191401 Arch Central 2015_...rvt

ATTACHMENT 4

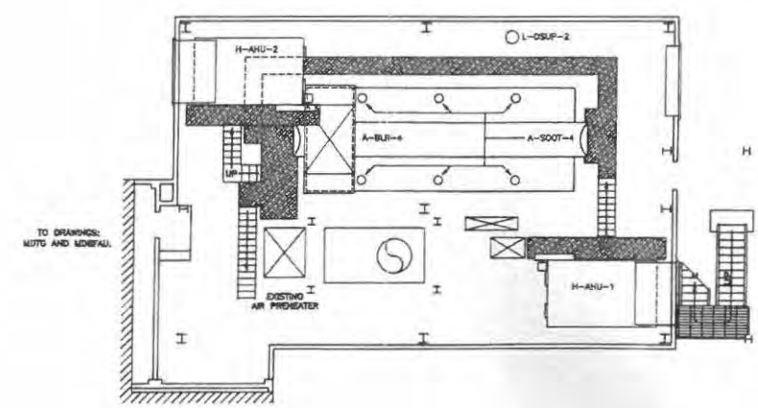


ZONE B – POWER PLANT ADD. – LEVEL 1

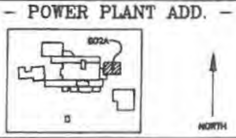


BLDG # AND ZONE LEGEND		
ZONE	BLDG #	BUILDING NAME
A	802, 802T, 806	POWER PLANT, TURBINE GENERATOR #3 ADDITION, SUBSTATION CONTROL HOUSE
B	802A, 802B	POWER PLANT ADDITION, BAGHOUSE ADDITION
C	801, 807	REVERSE OSMOSIS BLDG, CHILLER HOUSE
D	808	WATER TREATMENT FALSLITY

UNIVERSITY OF ALASKA FAIRBANKS UTILITIES OPERATION	
INSTITUTIONAL CONSERVATION PROGRAM TECHNICAL ASSISTANCE STUDY FOR UTILITIES OPERATION	
TITLE : POWER PLANT ADDITION, FLOOR 1	
ELEV. = 434 FEET AND 8 INCHES BLDG.#802A	
SCALE : 3/32" =1'	DATE : 06/18/90
AUTOCADD OPERATOR : MAXWELL J HOBSON	
DRAWN BY : MJH	DRAWING NUMBER: BLR4OA1
APPR BY : FARHAD	



ZONE B – POWER PLANT ADD. – MID-LEVEL



BLDG # AND ZONE LEGEND		
ZONE	BLDG #	BUILDING NAME
A	802, 803T, 806	POWER PLANT, TURBINE GENERATOR #3 ADDITION, SUBSTATION CONTROL HOUSE
B	802A, 802B	POWER PLANT ADDITION, BAGHOUSE ADDITION
C	801, 807	REVERSE OSMOSIS B.DG, CHILLER HOUSE
D	808	WATER TREATMENT FACILITY

UNIVERSITY OF ALASKA FAIRBANKS
UTILITIES OPERATION

INSTITUTIONAL CONSERVATION PROGRAM
TECHNICAL ASSISTANCE STUDY
FOR UTILITIES OPERATION

TITLE : POWER PLANT ADDITION, MID-LEVEL
ELEV. = 446 FEET AND 3 INCHES BLDG.#802A

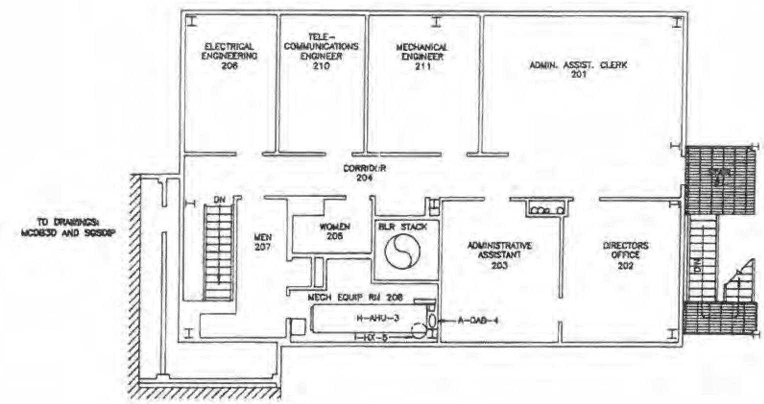
SCALE : 3/32"=1' | DATE : 05/18/90

AUTOCADD OPERATOR : MAXWELL J HOBSON

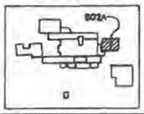
DRAWN BY : MJH

APPR BY : FARNAO

DRAWING NUMBER: BUR4OA2



ZONE B – POWER PLANT ADD. – FLOOR 2



BLDG # AND ZONE LEGEND		
ZONE	BLDG #	BUILDING NAME
A	802, 802T, 805	POWER PLANT, TURBINE GENERATOR #3 ADDITION, SUBSTATION CONTROL HOUSE
B	802A, 802B	POWER PLANT ADDITION, BAGHOUSE ADDITION
C	801, 807	REVERSE OSMOSIS BLDG, CHILLER HOUSE
D	808	WATER TREATMENT FACILITY

UNIVERSITY OF ALASKA FAIRBANKS UTILITIES OPERATION	
INSTITUTIONAL CONSERVATION PROGRAM TECHNICAL ASSISTANCE STUDY FOR UTILITIES OPERATION	
TITLE : POWER PLANT ADDITION, LEVEL 2	
ELEV. = 484 FEET AND 8 INCHES BLDG.#802A	
SCALE : 3/32"=1'	DATE : 05/16/90
AUTOCADD OPERATOR : MAXWELL J HOBSON	
DRAWN BY : MJH	DRAWING NUMBER: BLR40A3
APPR BY : FARHAD	

UNIVERSITY OF ALASKA FAIRBANKS
Administrative Services
P.O. Box 757900, Fairbanks, Alaska 99775-7500

Julie Queen, Interim Vice Chancellor
(907) 474-5479
julie.queen@alaska.edu
www.uaf.edu/adminsvc

April 23, 2019

Alice Edwards, Director
Division of Air Quality
Alaska Department of Environmental Conservation
PO Box 111800
Juneau, Alaska 99811

Transmitted digitally by email to: alice.edwards@alaska.gov
cc: cindy.heil@alaska.gov; deanna.huff@alaska.gov

RE: Fairbanks Serious $PM_{2.5}$ Nonattainment Area Best Available Control Technology (BACT) Determination – Economic Infeasibility of Sulfur Dioxide (SO_2) Emission Controls

Dear Ms. Edwards,

The University of Alaska Fairbanks (UAF) is providing additional information addressing certain aspects of the Alaska Department of Environmental Conservation (ADEC) BACT determinations associated with the Fairbanks Serious Nonattainment Area for particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 microns ($PM_{2.5}$) and requesting a determination of economic infeasibility of SO_2 emission controls. UAF understands that BACT determinations are a required component of the ADEC State Implementation Plan (SIP) submittal to address the $PM_{2.5}$ nonattainment area. UAF is concerned that a requirement to implement certain air pollutant emission controls will not be financially viable, particularly in light of existing state of Alaska budget issues. Specifically, UAF is addressing the ADEC preliminary BACT determination for SO_2 emission controls on emission unit (EU) 113, a predominantly coal-fired circulating fluidized bed (CFB) boiler. The maximum heat input capacity of EU 113 is 295.6 million British thermal units per hour (MMBtu/hr). EU 113 also has the capability to combust certain types of biomass (up to 20 or 25 percent of total heat input).

The ADEC preliminary BACT determination, dated March 22, 2018, presents the preliminary finding that BACT for SO_2 emissions from EU 113 would consist of the following requirements:

1) Control SO_2 emissions by operating and maintaining dry sorbent injection (DSI) and limestone injection at all times the unit is in operation.
2) The SO_2 emission rate shall not exceed 0.05 pounds per million British thermal unit (lb/MMBtu) averaged over a 3-hour period.
3) Burn low sulfur coal at all times that the dual fuel-fired boiler is combusting coal.
4) Demonstrate initial compliance with the SO_2 emission rate by conducting a performance test.

BACT is determined, in part, through a cost effectiveness analysis. ADEC prepared an analysis to determine the cost effectiveness of SO_2 controls deemed technically feasible for EU 113, including DSI. The ADEC analysis in Table 5-3 of the preliminary BACT determination presents a total capital cost of $4,394,193, total annualized costs of $2,246,238 per year, and a cost effectiveness of $7,536 per ton of SO_2 emissions removed. A capital recovery factor of 0.1098, calculated with 7 percent interest rate over a 15-year equipment life, was used to annualize costs. The cost effectiveness value is calculated by dividing the total annualized cost by the tons per year of air pollutant removed by the control device. In this case, DSI is estimated to remove up to 194 tons per year of SO_2. Contrary to the cost effectiveness figure of \$7,538 per ton of SO_2 emissions removed presented in Table 5-3, the cost effectiveness for DSI based on the ADEC total annualized cost of \$2,246,238 and the removal of 194 tons per year of SO_2 is actually \$11,578 per ton of SO_2 emissions removed.

The cost effectiveness value of \$11,578 per ton of SO_2 emissions removed likely *underestimates* the actual cost. The ADEC preliminary BACT determination implies that installing DSI on EU 113 to control SO_2 emissions would not involve significant retrofit costs. UAF disagrees with this premise and provided comments addressing this issue in a letter to ADEC dated May 23, 2018. The DSI calculations used in the "UAF SO2 Economic Analyses ADEC.xlsx" spreadsheet assume that the model is appropriate to apply to EU 113 even though EU 113 is a combined heat and power boiler and is not primarily used for electric power generation. The calculations assume that Trona would be used as the sorbent in the DSI system, when sodium bicarbonate or hydrated lime are much more likely sorbent options. The DSI cost analysis was originally developed by Sargent & Lundy (S&L) to evaluate cost and emissions impacts. The documentation available on the use of this cost model does not include information necessary to ensure that the calculations are properly applied to a specific situation, including

a. Types of plants to which the model is applicable (utility power generation, combined heat and power (CHP), cogeneration, other);
b. Applicable size range;
c. Equipment included in the Total Purchased Cost (TPC) calculation;
d. On-site bulk storage capacity;
e. A basis for selecting a "Retrofit factor" other than "1.0"; and
f. Data and other information used to develop and support the equations used in the spreadsheet.

Additionally, UAF has reached out to Stanley Consultants (the primary Engineering firm for the boiler replacement project) and they have advised UAF that since the new boiler design already incorporates control of SO_2 with the direct feed of limestone into the combustion chamber, additional control of SO_2 by injection of sorbent into the flue gas is unnecessary and would involve a costly retrofit of ductwork. Stanley contacted B&W (the supplier of the new boiler) on the issue and they have provided the following specific concerns with respect to DSI installation at EU 113:

a. A switch from hydrated lime to sodium bicarbonate is necessary to achieve reasonable effectiveness
b. The existing ductwork is not long enough to provide the recommended 2-3 seconds of residence time before the baghouse.
c. The lack of residence time will significantly degrade the performance of the DSI system. When considered along with the relatively low concentrations of sulfur in the flue gas, the best performance that can be expected is somewhere between 30 percent and 50 percent capture at normal operating loads without unreasonable injection rates (>5X the norm).
d. Also, given the constraints identified above, the normal ratio of sorbent to sulfur would not be sufficient to achieve the stated capture efficiencies. It is likely that a significantly higher ratio (more sorbent per pound of sulfur) will be required.
e. It may not be possible to operate the DSI system at lower loads due to a lack of flue gas temperature at the injection point.
f. There are no other possible injection points. The only way to increase the residence time is to modify the flue gas duct (at considerable expense)

g. At the sorbent injection rates that would be required to achieve the capture rates noted above, there is a potential for significant amounts of NO2 to be formed as a result of the chemical reaction which may form a brown plume and cause visual opacity issues[1].

B&W indicates that UAF *could* install a DSI system in the existing ductwork that would achieve some reduction in sulfur pollutants. That being said, the system would not be capable of the pollutant reductions typically associated with a new DSI system. Further, the injection of significant quantities of sorbent would likely result in the generation of unacceptable levels of NOx. It is theoretically possible that the flue gas duct could be modified to optimize the performance of a new DSI system, but these modifications would be extremely difficult and expensive to make. There was no consideration for a secondary emissions control system for SO2 when the facility was originally designed. As such the boiler and the baghouse are in close proximity to each other and the flue gas duct that connects them is surrounded by essential plant equipment, structural steel, and plant utilities.

The preamble to the Fine Particulate Matter National Ambient Air Quality Standards: State Implementation Plan Requirements; Final Rule dated August 24, 2016 includes guidance on preparing a Best Available Control Measures (BACM)/BACT determination in support of a serious $PM_{2.5}$ nonattainment area SIP. Specifically, determining whether an available control technology is economically feasible is addressed on page 58085 in volume 81 of the Federal Register. This section states

"…if a source contends that a source-specific control level should not be established because the source cannot afford the control measure or technology that is demonstrated to be economically feasible for purposes of BACM for other sources in its source category, the source should make its claim known to the state and support the claim with information regarding the impact of imposing the identified control measure or technology on the following financial indicators, to the extent applicable:

1. *Fixed and variable production costs ($/unit);*
2. *Product supply and demand elasticity;*
3. *Product prices (cost absorption vs. cost pass-through);*
4. *Expected costs incurred by competitors;*
5. *Company profits;*
6. *Employment costs;*
7. *Other costs (e.g. for BACM implemented by public sector entities)."*

Regardless of the exact cost, implementing DSI as SO_2 emissions controls on EU 113 is not financially possible for UAF. UAF is a public institution and an entity of the State of Alaska. On February 13, 2019 Governor Mike Dunleavy released his budget proposal for 2020. The University of Alaska (UA) is facing a proposed budget cut of $134 million, or 41 percent of the state's funding of $327 million, reducing the university's general fund support to $193 million. The cut is on top of state funding cuts that have occurred for four out of the last five years, resulting in program reductions and the loss of more than 1,200 faculty and staff. Under the Governor's spending plan, if his proposed cut is sustained by the legislature, it would be the largest year-over-year reduction in the university's history and would take UA back to 2002 funding levels. These cuts substantially impact UA and harm Alaska's ability to grow the highly trained workforce necessary to be economically competitive with other states.

The new UAF on-campus Combined Heat and Power Plant (CHPP) is an efficient and clean approach to generating electric power and heat from a single fuel source. At the UAF CHPP, fuel is burned to create

[1] August 2014 B&W Technical Paper "DSI Impacts on Visual Opacity"

steam, which both heats and cools campus and spins turbines to create electricity. Instead of purchasing electricity from the distribution grid and burning fuel in our on-site boilers to produce heat, UAF can use combined heat and power to provide both products as part of one combustion process.

If DSI were to be imposed as BACT for SO_2 emissions on EU 113, the expected impacts to the UAF financial indicators are as follows: (All costs from the 2017 UAF BACT Analysis adjusted for inflation from 2016 to 2019 dollars[2])

Capital Cost
UAF estimated in the January 2017 BACT analysis a total capital cost to install DSI control technology at EU ID 113 of $2,687,100.

Fixed and variable production costs
In the January 2017 UAF BACT Analysis, UAF estimated the total annualized cost for DSI control technology at $1,799,336 (not including labor and maintenance) with a cost effectiveness of $9,266 per ton. In the March 2018 ADEC BACT Determination, ADEC estimated the total annualized cost to be $2,246,238 with a cost effectiveness of $7,536 per ton. However, the true cost effectiveness based on the ADEC total annualized cost and the removal of 194 tons per year of SO_2 is at least $11,578 per ton of SO_2 removed as discussed above.

EU 113 is in the commissioning phase and has not yet operated at the maximum design production rate at steady state that would allow meaningful fixed and variable production cost ratios ($/kW or $/klb steam) to be calculated.

Cost Contributor	Annualized Cost
Production costs ($/kW or $/1,000 lb steam) *without* DSI	Not known
Production costs ($/kW or $/1,000 lb steam) *including* DSI	Not known
DSI Sorbent (sodium bicarbonate or hydrated lime)	$919,800[3]
DSI Electrical	$315,360[4]
DSI incremental ash disposal (at FNSB)	$150,000[5]
Labor for handling limestone and additional ash	$15,500[6]
Potentially voiding construction warranties	Not known

While the actual production costs of the new EU 113 boiler are not yet known, the following are the 2019 operating costs for the current UAF power plant[7]:

Operation	Cost
Electric	$0.203 per kilowatt hour
F&A	37.2%
Sewer	$7.00 per 1000 gallons
Steam	$15.47 per 1000 lb
Water	$7.10 per 1000 gallons

[2] 6 percent inflation adjustment 2016 to 2019 dollars per USInflationCalculator.com
[3] UAF BACT Analysis, January 2017, Table 5-7
[4] UAF BACT Analysis, January 2017, Table 5-7
[5] From estimated sorbent use and disposal cost at FNSB Solid Waste facility
[6] Estimated labor cost derived from estimated hours by UAF Director of Utilities 416 hours/yr @ $37.18/hr
[7] Data provided by the UAF Director of Utilities

<u>Product supply and demand elasticity</u>
Product supply and demand elasticity is not an applicable parameter because the steam heat and electricity generated through the use of EU 113 are not sold.

<u>Product prices (cost absorption vs. cost pass-through)</u>
Product price is not an applicable parameter because the steam heat and electricity generated through the use of EU 113 are not sold.

<u>Expected costs incurred by competitors</u>
Expected competitor costs is not an applicable parameter because the steam heat and electricity generated through the use of EU 113 are not sold. The UAF CHPP is not competing in the open or semi-open market.

<u>Company profits</u>
Company profits is not an applicable parameter because UAF is a State of Alaska facility, not a for-profit company.

<u>Employment costs</u>
UAF has requested and has not yet been provided the ADEC calculations for the economic analysis of SO_2 controls as discussed above.

<u>Other costs (e.g. for BACM implemented by public sector entities)</u>
UAF is a state institution with a budget that is determined by the Legislature. Spending funding on the DSI would cause funds to be diverted from the educational and research mission of the University. Impacts from the lack of funds include fewer staff to provide support services (grounds, maintenance, transportation, human resources, payroll, risk management, safety, fire and police, procurement), reduction in degree programs, further deferred maintenance which will cause deteriation of facilities and roads, inability to replace defunct equipment, and other impacts. The cost in dollars would be the amount of money that would be diverted for operations and maintenance of the DSI annually, plus the cost of construction of the plant and the interest payable on any bonds – the annualized cost of $2,246,238.

<u>Other factors</u>
It is unlikely that the incremental reduction of SO_2 emissions from EU ID 113 with the DSI system installed (compared to air quality permit limits) would significantly reduce $PM_{2.5}$ concentrations in the FNSB serious nonattainment area because:

- The stack height of EU 113 is 210 feet.
- The UAF CHPP is located towards the west end of Fairbanks of the serious nonattainment area. Flow through the airshed is comparable to flow through the local watershed (roughly east to west), therefore with normal conditions in place, impacts to the non-attainment area should be minimal.

DSI technology requires the addition of limestone, lime, or sodium bicarbonate to the boiler flue gas post-combustion prior to the baghouse. Any unreacted sorbent could alter the physical properties of the coal ash, including the leachability of metals. With an estimated quantity of 1314 tons per year of sorbent used in the DSI process at UAF, the amount of waste material captured in the baghouse will increase significantly. UAF could face the added significant cost of disposal of an increased volume of coal ash with increased hazardous properties if UAF is compelled to install DSI technology at EU 113.

UAF will commit to use of ULSD on its existing permitted fuel burning equipment that is not currently required to use this type of fuel, but understands that this will be a requirements in the serious SIP. However, any additional pollution control equipment added to any of our units will be an additional hardship to the University and its mission. Please consider this request for economic and technological infeasibility of installation of additional pollution control equipment on our permitted units. UAF will commit to completing additional source testing for SO_2 to substantiate the reduction in sulfur due to elimination of the existing coal-fired boilers and the use of the new circulated fluidized bed boiler. UAF will complete additional SO_2 source testing within 6 months after initial start-up.[8] Also, once the facility is operational, EU IDs 3 and 4 will reduce their usage dramatically which will also lower the sulfur emissions from UAF.

If you have any questions, please contact Russ Steiger at 907-474-5812 or rhsteiger@alaska.edu or Frances Isgrigg at 907-474-5487 or fisgrigg@alaska.edu.

Sincerely,

Julie Queen
Interim Vice Chancellor for Administrative Services
University of Alaska Fairbanks

[8] Initial Startup: The first time that steam is produced by the boiler and used to produce heat and/or drive the turbine(s) to produce electricity – per 1979 EPA Instruction Manual for Clarification of Startup in Source Categories Affected by New Source Performance Standards.

Although not explicitly stated in the definition, startup excludes firing an emissions unit for the purpose of commissioning prior to the emissions unit becoming operational. Pre-startup and startup are discussed in the 1979 EPA Instruction Manual for Clarification of Startup in Source Categories Affected by New Source Performance Standards.