Fort Wainwright Plant BACT Cover Page

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ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION
Air Permits Program

BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION ADDENDUM
for
Fort Wainwright
US Army Garrison and Doyon Utilities

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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

Fort Wainwright is a military installation located within and adjacent to the city of Fairbanks, Alaska, in the Tanana River Valley. The EUs located at the Central Heat and Power Plant (CHPP) at Fort Wainwright in Fairbanks, AK are either owned and operated by a private utility company, Doyon Utilities, LLC. (DU), or by U.S. Army Garrison Fort Wainwright (FWA). The two entities, DU and FWA, comprise a single stationary source operating under two permits.

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]

The initial BACT Determination for Fort Wainwright was included in Part 2 of Appendix III.D.7.07 Control Strategies Chapter, in the State Air Quality Control Plan adopted on November 19, 2019, with amendments adopted on November 18, 2020, as part of a complete SIP package.[2] The *EPA's Air Plan Partial Approval and Partial Disapproval; AK, Fairbanks North Star Borough; 2006 24-hour $PM_{2.5}$ Serious Area and 189(d) Plan*[3] published in the Federal Register on December 5, 2023 (*88 Fed. Reg. 84655*) disapproved of Alaska's initial BACT determinations for $PM_{2.5}$ and SO_2 controls. This BACT addendum addresses the EPA's disapproval of the significant EUs listed in the DU permit AQ1121TVP02, Revision 2 and the FWA permit AQ0236TVP04, for $PM_{2.5}$ and SO_2 controls. The BACT addendum also accounts for EPA's comments listed in Memorandum dated August 24, 2022 from Zach Hedgpeth, LSASD to Matthew Jentgen, ARD.[4] This BACT addendum provides the Department's review of the BACT analysis for $PM_{2.5}$, and BACT analysis for sulfur dioxide (SO_2) emissions, which is a precursor pollutant that can form $PM_{2.5}$ in the atmosphere post combustion. Note that the section for oxides of nitrogen (NOx), which is also a precursor pollutant that can form $PM_{2.5}$ in the atmosphere post combustion, has been removed from this addendum because the EPA has approved[3] of the Department's comprehensive NOx precursor demonstration under 40 C.F.R. 51.1006(a)(1) and 51.1010(a)(2)(ii).

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

[2] Background and detailed information regarding Fairbanks $PM_{2.5}$ State Implementation Plan (SIP) can be found at **http://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-serious-sip/**.

[3] The EPA's Air Plan Partial Approval and Partial Disapproval; AK, Fairbanks North Star Borough; 2006 24-hour $PM_{2.5}$ Serious Area and 189(d) Plan can be found at **https://www.regulations.gov/document/EPA-R10-OAR-2022-0115-0426**.

[4] Document 000009_EPA Technical Support Document – FTWW-Doyon BACT TSD v200221020_Redacted: **https://www.regulations.gov/document/EPA-R10-OAR-2022-0115-0217**

The following sections review Fort Wainwright'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 technically available control technologies 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 Fort Wainwright that emit $PM_{2.5}$ and SO_2, establish emission limits which represent BACT, and assess the level of monitoring, recordkeeping, and reporting (MR&R) necessary to ensure Fort Wainwright 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 and Table B present the EUs subject to BACT review.

Table A: Privatized Emission Units Subject to BACT Review

EU ID[1]	Description of EU	Rating/Size		Location
1	Coal-Fired Boiler 3	230	MMBtu/hr	Central Heating and Power Plant (CHPP)
2	Coal-Fired Boiler 4	230	MMBtu/hr	CHPP
3	Coal-Fired Boiler 5	230	MMBtu/hr	CHPP
4	Coal-Fired Boiler 6	230	MMBtu/hr	CHPP
5	Coal-Fired Boiler 7	230	MMBtu/hr	CHPP
6	Coal-Fired Boiler 8	230	MMBtu/hr	CHPP
7a	South Coal Handling Dust Collector DC-01	13,150	acfm	CHPP
7b	South Underbunker Dust Collector DC-02	884	acfm	CHPP
7c	North Coal Handling Dust Collector NDC-1	9,250	acfm	CHPP
8	Backup Generator Engine	2,937	hp	CHPP
9	Emergency Generator Engine	353	hp	Building 1032
14	Emergency Generator Engine	320	hp	Building 1563
22	Emergency Generator Engine	35	hp	Building 3565
23	Emergency Generator Engine	155	hp	Building 3587
29a	Emergency Pump Engine	**74**	hp	Building **3565**
30a	Emergency Pump Engine	**80**	hp	Building 3403
31a	Emergency Pump Engine	**74**	hp	Building 3724
32a	Emergency Pump Engine	**80**	hp	Building 4162
33a	Emergency Pump Engine	75	hp	Building 1002
34	Emergency Pump Engine	220	hp	Building 3405
35	Emergency Pump Engine	55	hp	Building 4023
36	Emergency Pump Engine	220	hp	Building 3563
37a	**Emergency Pump Engine**	**75**	**hp**	**Building 507**
51a	DC-1 Fly Ash Dust Collector	3,620	acfm	CHPP
51b	DC-2 Bottom Ash Dust Collector	3,620	acfm	CHPP

EU ID[1]	Description of EU	Rating/Size	Location
52	Coal Storage Pile	N/A	CHPP

Table B: Fort Wainwright Army Emission Units Subject to BACT Review

EU ID[1]	Description of EU	Rating/Size	Location
8	Backup Diesel-Fired Boiler 1	19 MMBtu/hr	Basset Hospital
9	Backup Diesel-Fired Boiler 2	19 MMBtu/hr	Basset Hospital
10	Backup Diesel-Fired Boiler 3	19 MMBtu/hr	Basset Hospital
11	Backup Diesel-Electric Generator 1	900 kW	Basset Hospital
12	Backup Diesel-Electric Generator 2	900 kW	Basset Hospital
13	Backup Diesel-Electric Generator 3	900 kW	Basset Hospital
22	VOC Extraction and Combustion	N/A	
23	Fort Wainwright Landfill	1.97 million cubic meters	
24	Aerospace Activities	N/A	
26	Emergency Generator	324 hp	Building 2132
27	Emergency Generator	67 hp	Building 1580
28	Emergency Generator	398 hp	Building 3406
29	Emergency Generator	47 hp	Building 3567
30	Fire Pump	275 hp	Building 2089
31	Fire Pump #1	235 hp	Building 1572
32	Fire Pump #2	235 hp	Building 1572
33	Fire Pump #3	235 hp	Building 1572
34	Fire Pump #4	235 hp	Building 1572
35	Fire Pump #1	240 hp	Building 2080
36	Fire Pump #2	240 hp	Building 2080
37	Fire Pump	105 hp	Building 3498
38	Fire Pump #1	120 hp	Building 5009
39	Fire Pump #2	120 hp	Building 5009
40	**Diesel**-Fired Boiler	2.6 MMBtu/hr	Building 5007
50	Emergency Generator Engine	762 hp	Building 1060
51	Emergency Generator Engine	762 hp	Building 1060
52	Emergency Generator Engine	82 hp	Building 1193
53	Emergency Generator Engine	587 hp	Building 1555
54	Emergency Generator Engine	1,059 hp	Building 2117
55	Emergency Generator Engine	212 hp	Building 2117
56	Emergency Generator Engine	176 hp	Building 2088
57	Emergency Generator Engine	212 hp	Building 2296
58	Emergency Generator Engine	71 hp	Building 3004
59	Emergency Generator Engine	35 hp	Building 3028
60a	**Emergency Generator Engine**	**230 hp**	Building 3407
61	Emergency Generator Engine	50 hp	Building 3703
62	Emergency Generator Engine	18 hp	Building 5108
63	Emergency Generator	68 hp	Building 1620
64	Emergency Generator	274 hp	Building 1054
65	Emergency Generator	274 hp	Building 4390
66	**Emergency Generator**	**235 hp**	**Building 3007**
67	**Emergency Generator**	**67 hp**	**Building 2121**
68	**Emergency Generator**	**324 hp**	**Building 3025**
69	**Emergency Generator**	**86 hp**	**Building 3030**

Five-Step BACT Determinations
The following sections explain the steps used to determine BACT for $PM_{2.5}$ and SO_2 for the applicable equipment.

Step 1 Identify All Potentially Available Control Technologies
The Department identifies all available control technologies for the EU 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 controls 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 $PM_{2.5}$ and SO_2 emissions from equipment similar to those listed in Table A and Table B**. Doyon has also identified and proposed multiple pollution control technologies.**

Step 2 Eliminate Technically Infeasible Control Technologies:
The Department evaluates the technical feasibility of each control option 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 4 and 5 present the Department's BACT determinations for $PM_{2.5}$ 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 Fort Wainwright's BACT analysis and made BACT determinations for $PM_{2.5}$ and SO_2 for Fort Wainwright. These BACT determinations are based on the information submitted by Fort Wainwright in their analysis, information from vendors, suppliers, sub-contractors, RBLC, and an exhaustive internet search.

3. BACT DETERMINATION FOR NOx

As discussed in the Section 1 Introduction, this BACT addendum has removed the previous NOx BACT determinations included in the State Air Quality Control Plan adopted on November 19, 2019, with amendments adopted on November 18, 2020,[2] because the optional comprehensive precursor demonstration (as allowed under 40 C.F.R. 51.1006(1) and 51.1010(a)(2)(ii)) for the precursor gas NOx for point sources illustrates that NOx controls are not needed. The Department submitted with the Serious SIP a final comprehensive precursor demonstration as justification not to require post emission controls for NOx. Please see the precursor demonstration for NOx in the Serious SIP Modeling Chapter III.D.7.8.[2] The $PM_{2.5}$ 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.[5] DEC's NOx precursor demonstration was approved in *EPA's Air Plan Partial Approval and Partial Disapproval; AK, Fairbanks North Star Borough; 2006 24-hour $PM_{2.5}$ Serious Area and 189(d) Plan*[3] published in the Federal Register on December 5, 2023 (*88 Fed. Reg. 84655*).

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, and UAF for the Combined Heat and Power Plant.

4.1 $PM_{2.5}$ BACT for the Industrial Coal-Fired Boilers

Possible $PM_{2.5}$ emission control technologies for coal-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 for coal-fired boilers are summarized in Table 4-1.

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

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 industrial coal-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 Industrial Coal-Fired Boilers
From research, the Department identified the following technologies as available for control of $PM_{2.5}$ emissions from industrial coal-fired boilers:

(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,[6] pulse-jet,[7] and reverse-air.[8] 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 industrial coal-fired boilers.

(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%.[9] Wet ESPs have the advantage of controlling some amount of condensable particulate 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%.[10] The

6 https://www3.epa.gov/ttn/catc/dir1/ff-shaker.pdf
7 https://www3.epa.gov/ttn/catc/dir1/ff-pulse.pdf
8 https://www3.epa.gov/ttn/catc/dir1/ff-revar.pdf
9 https://www3.epa.gov/ttn/catc/dir1/fwespwpi.pdf
https://www3.epa.gov/ttn/catc/dir1/fwespwpl.pdf
10 https://www3.epa.gov/ttn/catc/dir1/fdespwpi.pdf
https://www3.epa.gov/ttn/catc/dir1/fdespwpl.pdf

Department considers ESP a technically feasible control technology for the industrial coal-fired boilers.

(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%.[11] 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 a technically feasible control technology for the industrial coal-fired boilers.

(d) Mechanical Collectors (Cyclones)
Cyclones are used in industrial applications to remove particulate matter from 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 industrial coal-fired boilers.

(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 industrial coal-fired boilers.

(f) Good Combustion Practices (GCPs)

[11] 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

Good combustion techniques for coal boilers take into account operator practices, maintenance knowledge, maintenance practices, adequate stoichiometric (fuel/air)ratio, combustion zone residence time, temperature, turbulence, fuel quality, combustion air distribution, fuel/waste dispersion. The Department considers GCPs a technically feasible control option for the coal-fired boilers.

Step 2 - Eliminate Technically Infeasible $PM_{2.5}$ Control Technologies for the Coal-Fired Boilers
As explained in Step 1 of Section 4.1, the Department does not consider a settling chamber as a technically feasible technology to control particulate matter emissions from the industrial coal-fired boilers.

Step 3 - Rank the Remaining $PM_{2.5}$ Control Technologies for the Industrial Coal-Fired Boilers
The following control technologies have been identified and ranked by efficiency for the control of $PM_{2.5}$ from the industrial coal-fired boilers:

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

Step 4 - Evaluate the Most Effective Controls

Fort Wainwright BACT Proposal

Fort Wainwright proposes the following as BACT for $PM_{2.5}$ emissions from the coal-fired boilers:

(a) $PM_{2.5}$ emissions from the operation of the coal-fired boilers shall be controlled by installing, operating, and maintaining a full stream baghouse.

(b) $PM_{2.5}$ emissions from the coal-fired boilers shall not exceed 0.05 gr/dscf over a 3-hour averaging period.

(c) Initial compliance with the proposed $PM_{2.5}$ emission limit will be demonstrated by conducting a performance test for $PM_{2.5}$, including condensable PM; and

(d) **Maintain compliance with State opacity standards listed under 50.055(a)(9).**

Step 5 - Selection of $PM_{2.5}$ BACT for the Industrial Coal-Fired Boilers
The Department's finding is that BACT for $PM_{2.5}$ emissions from the coal-fired boilers is as follows:

(a) $PM_{2.5}$ emissions from DU EUs 1 through 6 shall be controlled by operating and maintaining fabric filters (full stream baghouse) and using good combustion practices at all times the units are in operation;

(b) $PM_{2.5}$ emissions from DU EUs 1 through 6 shall be controlled by maintaining good combustion practices at all times the units are in operation;

(c) $PM_{2.5}$ emissions from DU EUs 1 through 6 shall not exceed 0.045 lb/MMBtu[12] averaged over a 3-hour period.

(d) Initial compliance with the proposed $PM_{2.5}$ emission limit will be demonstrated by conducting a performance test to obtain an emission rate; and

(e) Maintain compliance with the State opacity standards in 50.055(a)(9).

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
Fort Wainwright	6 Coal-Fired Boilers	1380 MMBtu/hr	0.045 lb/MMBtu[12]	Full stream baghouse; **Good Combustion Practices**
UAF	Dual Fuel-Fired Boiler	295.6 MMBtu/hr	0.012 lb/MMBtu[13]	Fabric Filters; **Good Combustion Practices**
Chena	**4 Coal-Fired Boilers**	**497 MMBtu/hr**	**0.045 lb/MMBtu[12]**	**Full stream baghouse**; **Good Combustion Practices**

4.2 $PM_{2.5}$ BACT for the Diesel-Fired Boilers

Possible $PM_{2.5}$ emission control technologies for 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 boilers are summarized in Table 4-3.

Table 4-3. RBLC Summary of $PM_{2.5}$ Control for 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.

12 The 0.045 lb/MMBtu emission rate is calculated using EPA AP-42 Tables 1.1-5 (0.04 lb/MMBtu for spreader stoker boilers with a baghouse) and 1.1-6 (0.01A lb/ton for $PM_{2.5}$ sized particles for a boiler with a baghouse converted to lb/MMBtu using the typical gross as received heat value of 7,560 Btu/lb and an ash content (A) of 7 percent). Heat and ash content of the Usibelli coal is identified in the coal data sheet at: **http://usibelli.com/coal/data-sheet**.

13 Boiler manufacturer Babcock & Wilcox's $PM_{2.5}$ emission guarantee, used to calculate potential to emit in Air Quality Permit AQ0316MSS06.

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

(a) Scrubbers
The theory behind scrubbers was discussed in detail in the $PM_{2.5}$ BACT section for the industrial coal-fired boilers and will not be repeated here. The Department considers scrubbers as a technically feasible control technology for the diesel-fired boilers.

(b) Limited Operation
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 diesel-fired boilers.

(c) Good Combustion Practices
The theory of GCPs was discussed in detail in the $PM_{2.5}$ BACT section for the industrial coal-fired boilers 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 diesel-fired boilers.

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

Step 3 - Rank the Remaining $PM_{2.5}$ Control Technologies for the Diesel-Fired Boilers
The following control technologies have been identified and ranked by efficiency for the control of $PM_{2.5}$ emissions from the diesel-fired boilers:

(a)	Scrubber	(50% - 99% Control)
(b)	Limited Operation	(94% Control)
(c)	Good Combustion Practices	(Less than 40% Control)

Step 4 - Evaluate the Most Effective Controls

Fort Wainwright BACT Proposal

Fort Wainwright proposes good combustion practices as BACT for $PM_{2.5}$ emissions from the diesel-fired boilers.

Department Evaluation of BACT for $PM_{2.5}$ Emissions from Diesel-Fired Boilers

The Department reviewed Fort Wainwright's proposal and finds that the **four significant sized boilers**[14] have a combined PTE of less than one tpy for $PM_{2.5}$. At one tpy, the cost effectiveness in terms of dollars per ton for add-on pollution control for these units is economically infeasible.

[14] **The Department's revised BACT finding for the diesel-fired boilers removes the insignificant boilers that are associated with Fort Wainwright. The Department notes that no other insignificant boilers from other sources were originally included in the BACT analyses and that the insignificant emissions units will have to meet the BACM requirements under 18 AAC 50.078, which includes the requirement to combust fuel oil that contains no more than 1,000 ppmw sulfur.**

Step 5 - Selection of $PM_{2.5}$ BACT for the Diesel-Fired Boilers

The Department's finding is that BACT for $PM_{2.5}$ emissions from the diesel-fired boilers **EUs 8 – 10 and 40** is as follows:

(a) $PM_{2.5}$ emissions from the diesel-fired boilers **EUs 8 – 10 and 40** shall not exceed **0.016 lb/MMBtu**[15] averaged over a 3-hour period;

(b) Combined operating limit of 600 hours per year for FWA EUs 8, 9, and 10; and

(c) Maintain good combustion practices by following the manufacturer's maintenance procedures at all times of **operation and complying with the boiler tune-up requirements of NESHAP Subpart DDDDD.**

Table 4-4 lists the proposed $PM_{2.5}$ 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 4-4. Comparison of $PM_{2.5}$ BACT for the Diesel-Fired Boilers at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
Fort Wainwright	**4** Diesel-Fired Boilers	< 100 MMBtu/hr	**0.016** lb/MMBtu[15]	Good Combustion Practices
UAF	**6** Diesel-Fired Boilers	< 100 MMBtu/hr	**0.016** lb/MMBtu[15]	Limited Operation Good Combustion Practices
Zehnder	2 Diesel-Fired Boilers	< 100 MMBtu/hr	**0.016** lb/MMBtu[15]	Good Combustion Practices

4.3 $PM_{2.5}$ BACT for the Large Diesel-Fired Engines, Fire Pumps, and Generators

Possible $PM_{2.5}$ 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 4-5.

Table 4-5. RBLC Summary of $PM_{2.5}$ Control for 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.

[15] 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 **1.3-7** ($PM_{2.5}$ size-specific factor from distillate oil, **0.83 lb/1,000 gal**) converted to lb/MMBtu. **Note that the E.F. has been corrected from the previous SIP because the small boilers are considered "commercial" under Table 1.3-7 and not "industrial" under Table 1.3-6.**

Step 1 - Identification of $PM_{2.5}$ Control Technology for the Large Diesel-Fired Engines
From research, the Department identified the following technologies as available for control of $PM_{2.5}$ emissions from diesel-fired engines rated at 500 hp or greater:

(a) Diesel Particulate Filter (DPF)
DPFs are 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 engines.

(b) 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 engines.

(c) 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. The Department considers positive crankcase ventilation a technically feasible control technology for the large diesel-fired engines.

(d) Low Sulfur Fuel
Low sulfur fuel has been known to reduce particulate matter emissions. The Department considers low sulfur fuel as a feasible control technology for the large diesel-fired engines.

(e) 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 large diesel-fired engines.

(f) Federal Emission Standards

RBLC $PM_{2.5}$ 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. The Department considers NSPS Subpart IIII a technically feasible control technology for the large diesel-fired engines.

(g) Limited Operation
FWA EUs 11, 12, and 13 currently operate under a combined annual limit of less than 600 hours per year to avoid classification as a PSD major modification for NOx. 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 engines.

(h) Good Combustion Practices
The theory of GCPs was discussed in detail in the $PM_{2.5}$ BACT section for the coal-fired boilers 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 Engines
All control technologies identified are technically feasible to control particulate emissions from the large diesel-fired engines.

Step 3 - Rank the Remaining $PM_{2.5}$ Control Technologies for the Large Diesel-Fired Engines
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)	Limited Operation	(94% Control)
(a)	Diesel Particulate Filters	(85% Control)
(h)	Good Combustion Practices	(Less than 40% Control)
(b)	Diesel Oxidation Catalyst	(30% Control)
(e)	Low Ash Diesel	(25% Control)
(c)	Positive Crankcase Ventilation	(10% Control)
(f)	Federal Emission Standards	(Baseline)

Step 4 - Evaluate the Most Effective Controls

Fort Wainwright BACT Proposal

Fort Wainwright proposes the following as BACT for $PM_{2.5}$ emissions from the large diesel-fired engines:

(a) Combined operating limit of 600 hours per year for FWA EUs 11, 12, and 13;

(b) For engines manufactured after the applicability dates of 40 C.F.R. 60 Subpart IIII, BACT is selected as compliance with 40 C.F.R Part 60 Subpart IIII. For older engines, compliance with 40 C.F.R. 63 Subpart ZZZZ is proposed as BACT; and

(c) Combust only ULSD.

Department Evaluation of BACT for $PM_{2.5}$ Emissions from the Large Diesel-Fired Engines

The Department reviewed Fort Wainwright's proposal finds that $PM_{2.5}$ emissions from the large diesel-fired engines can be controlled by limiting the use of the units during non-emergency operation as well as complying with the applicable federal emission standards.

Step 5 - Selection of $PM_{2.5}$ BACT for the Large Diesel-Fired Engines

The Department's finding is that the BACT for $PM_{2.5}$ emissions from the large diesel-fired engines is as follows:

(a) Combined operating limit of 600 hours per year for FWA EUs 11, 12, and 13;

(b) Limit DU EU 8 to 500 hours of operation per year;

(c) Limit non-emergency operation of FWA EUs 50, 51, 53, and 54 to no more than 100 hours each per year;

(d) Combust only ULSD;

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

(f) Comply with the numerical BACT emission limits listed in Table 4-6 for $PM_{2.5}$.

Table 4-6. Proposed $PM_{2.5}$ BACT Limits for Large Diesel-Fired Engines

Location	EU	Year	Description	Size	Status	BACT Limit	Proposed BACT
DU	8	2009	Generator Engine	**2,937 hp**	Certified Engine	0.15 g/hp-hr	40 CFR 60 Subpart IIII
FWA	11	2003	Caterpillar 3512	**1,206 hp**	AP-42 Table 3.4-1	0.32 g/hp-hr	Limit combined operation to 600 hours per 12-month rolling period.
FWA	12	2003	Caterpillar 3512	**1,206 hp**	AP-42 Table 3.4-1	0.32 g/hp-hr	
FWA	13	2003	Caterpillar 3512	**1,206 hp**	AP-42 Table 3.4-1	0.32 g/hp-hr	
FWA	51	2010	Generator Engine	**762 hp**	Certified Engine	0.15 g/hp-hr	40 CFR 60 Subpart IIII
FWA	50	2010	Generator Engine	**762 hp**	Certified Engine	0.15 g/hp-hr	40 CFR 60 Subpart IIII
FWA	53	2008	Generator Engine	**587 hp**	Certified Engine	0.15 g/hp-hr	40 CFR 60 Subpart IIII
FWA	54	2005	Generator Engine	**1,059 hp**	AP-42 Table 3.4-1	0.32 g/hp-hr	Good Combustion Practices

Table 4-7 lists the proposed $PM_{2.5}$ 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 4-7. Comparison of $PM_{2.5}$ BACT for Large Diesel Engines at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
UAF	Large Diesel-Fired Engines	**> 500 hp**	**0.05 -** 0.32 g/hp-hr	Positive Crankcase Ventilation **Ultra-Low Sulfur Diesel** Limited Operation
Fort Wainwright	8 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 Engine	600 hp	0.32 g/hp-hr	Positive Crankcase Ventilation Good Combustion Practices

Facility	Process Description	Capacity	Limitation	Control Method
GVEA Zehnder	2 Large Diesel-Fired Engines	11,000 hp (each)	0.32 g/hp-hr	Limited Operation Good Combustion Practices

4.4 $PM_{2.5}$ BACT for the Small Emergency Engines, Fire Pumps, and Generators

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 diesel-fired engines are summarized in Table 4-8.

Table 4-8. RBLC Summary for $PM_{2.5}$ Control for Small Diesel-Fired Engines

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 diesel-fired engines rated at less than 500 hp:

(a) Diesel Particulate Filter
The theory behind DPF was discussed in detail in the $PM_{2.5}$ BACT section for the large diesel-fired engines 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 section 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/ Sulfur 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 engine. Low sulfur fuel has been known to reduce particulate matter emissions. The Department considers low sulfur fuel as a feasible control technology for the small diesel-fired engines.

(d) Federal Emission Standards
The theory behind federal emission standards was discussed in detail in the $PM_{2.5}$ BACT section for the large diesel-fired engines 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
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 engines.

(f) Good Combustion Practices
The theory of GCPs was discussed in detail in the $PM_{2.5}$ BACT section for the coal-fired boilers 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:

(e)	Limited Operation	(94% Control)
(a)	Diesel Particulate Filters	(60% - 90% Control)
(b)	Diesel Oxidation Catalyst	(40% Control)
(f)	Good Combustion Practices	(Less than 40% Control)
(c)	Low Ash/Sulfur Diesel	(25% Control)
(d)	Federal Emission Standards	(Baseline)

Step 4 - Evaluate the Most Effective Controls

Fort Wainwright BACT Proposal

Fort Wainwright proposes the following as BACT for $PM_{2.5}$ emissions from the small diesel-fired engines:

(a) Limited Operation

(b) Good Combustion Practices;

(c) For engines manufactured after the applicability dates of 40 C.F.R. 60 Subpart IIII, BACT is proposed as compliance with 40 C.F.R Part 60 Subpart IIII. For older engines, compliance with the 40 C.F.R. 63 Subpart ZZZZ is proposed as BACT; and

(d) Combust only ULSD.

Department Evaluation of BACT for $PM_{2.5}$ Emissions from Small Diesel-Fired Engines

The Department reviewed Fort Wainwright's proposal and found that in addition to maintaining good combustion practices, complying with federal requirements, and combusting only ULSD: limiting operation of the small diesel-fired engines during non-emergency operation to no more than 100 hours per year each is BACT for $PM_{2.5}$.

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) Combust only ULSD;

(b) Limit non-emergency operation of DU EUs 9, 14, 22, 23, 29a, 30a, 31a, 32a, 33a, 34, 35, 36**, 37a** FWA EUs 26 through 39, 52, and 55 through **69** to no more than 100 hours per year each ;

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

(d) Comply with the numerical BACT emission limits listed in Table 4-9 for $PM_{2.5}$.

Table 4-9. Proposed $PM_{2.5}$ BACT Limits for Small Diesel-Fired Engines

Location	EU	Year	Description	Size	Status	BACT Limit	Proposed BACT
DU	9	1988	Generator Engine	353 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	Limited Operation for Non-Emergency Use (100 hours per year each) Good Combustion Practices Combust ULSD
DU	14	2008	Generator Engine	320 hp	Certified Engine	0.2 g/kW-hr	
DU	22	1989	Generator Engine	35 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
DU	23	2003	Generator Engine	155 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
DU	**29a**	**2015**	**Lift Pump Engine**	**74 hp**	**Certified Engine**	**0.3 g/hp-hr**	
DU	**30a**	**2018**	**Lift Pump Engine**	**80 hp**	**Certified Engine**	**0.3 g/hp-hr**	
DU	**31a**	**2015**	**Lift Pump Engine**	**74 hp**	**Certified Engine**	**0.3 g/hp-hr**	
DU	**32a**	**2018**	**Lift Pump Engine**	**80 hp**	**Certified Engine**	**0.3 g/hp-hr**	
DU	**33a**	**2015**	**Lift Pump Engine**	**75 hp**	**Certified Engine**	**0.3 g/hp-hr**	
DU	34	1995	Well Pump Engine	220 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
DU	35	2009	Well Pump Engine	55 hp	Certified Engine	0.3 g/hp-hr	
DU	36	1995	Well Pump Engine	220 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
DU	**37a**	**2015**	**Lift Pump Engine**	**75 hp**	**Certified Engine**	**0.3 g/hp-hr**	
FWA	26	2012	QSB7-G3 NR3	295 hp	Certified Engine	0.02 g/kW-hr	
FWA	27	2009	4024HF285B	67 hp	Certified Engine	0.3 g/kW-hr	
FWA	28	2007	CAT C9 GENSET	398 hp	Certified Engine	0.2 g/kW-hr	
FWA	29	ND	TM30UCM	47 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
FWA	30	2007	JW64-UF30	275 hp	Certified Engine	0.2 g/kW-hr	
FWA	31	1994	DDFP-04AT	235 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
FWA	32	1994	DDFP-04AT	235 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
FWA	33	1994	DDFP-04AT	235 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
FWA	34	1994	DDFP-04AT	235 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
FWA	35	1977	N-855-F	240 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
FWA	36	1977	N-855-F	240 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
FWA	37	2005	JU4H-UF40	94 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
FWA	38	1996	PDFP-06YT	120 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
FWA	39	1996	PDFP-06YT	120 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
FWA	52	2002	Generator Engine	82 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	

Location	EU	Year	Description	Size	Status	BACT Limit	Proposed BACT
FWA	55	2005	Generator Engine	212 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
FWA	56	2007	Generator Engine	176 hp	Permit condition 23.1c	0.40 g/hp-hr	
FWA	57	2005	Generator Engine	212 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
FWA	58	2007	Generator Engine	71 hp	Certified Engine	0.4 g/kW-hr	
FWA	59	1976	Generator Engine	35 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
FWA	**60a**	**2023**	**Generator Engine**	**230 hp**	**Certified Engine**	**0.2 g/kW-hr**	
FWA	61	1993	Generator Engine	50 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
FWA	62	2011	Generator Engine	18 hp	Certified Engine	0.4 g/kW-hr	
FWA	63	2003	Generator Engine	68 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
FWA	64	2010	Generator Engine	274 hp	Certified Engine	0.2 g/kW-hr	
FWA	65	2010	Generator Engine	274 hp	Certified Engine	0.2 g/kW-hr	
FWA	**66**	**2014**	**Generator Engine**	**235 hp**	**Certified Engine**	**0.2 g/kW-hr**	
FWA	**67**	**2016**	**Generator Engine**	**67 hp**	**Certified Engine**	**0.4 g/kW-hr**	
FWA	**68**	**2017**	**Generator Engine**	**324 hp**	**Certified Engine**	**0.2 g/kW-hr**	
FWA	**69**	**2023**	**Generator Engine**	**86 hp**	**Certified Engine**	**0.4 g/kW-hr**	

Table 4$_{10}$ lists the proposed $PM_{2.5}$ 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$_{10}$. Comparison of $PM_{2.5}$ BACT for Small Engines at Nearby Power Plants

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

4.5 $PM_{2.5}$ BACT for the Material Handling

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 4-11.

Table 4-11. RBLC Summary for $PM_{2.5}$ Control for Material Handling

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
From research, the Department identified the following technologies as available for $PM_{2.5}$ control of materials handling:

(a) Fabric Filters
The theory behind fabric filters was discussed in detail in the $PM_{2.5}$ BACT section for the industrial coal-fired boilers and will not be repeated here. The Department considers fabric filters a technically feasible control technology for material handling.

(b) Enclosure
Enclosure structures shelter material from wind entrainment and are used to control particulate emissions. Enclosures can either fully or partially enclose the source and control efficiency is dependent on the level of enclosure.

(c) Wet and Dry Electrostatic Precipitators
The theory behind ESPs was discussed in detail in the $PM_{2.5}$ BACT section for the industrial coal-fired boilers and will not be repeated here. The Department considers ESPs a technically feasible control technology for material handling.

(d) Wet Scrubbers
The theory behind wet scrubbers was discussed in detail in the $PM_{2.5}$ BACT section for the industrial coal-fired boilers and will not be repeated here. The Department considers wet scrubbers a technically feasible control technology for material handling.

(e) Mechanical Collectors (Cyclones)
The theory behind cyclones was discussed in detail in the $PM_{2.5}$ BACT section for the industrial coal-fired boilers and will not be repeated here. The Department considers cyclones a technically feasible control technology for material handling.

(f) 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.

(g) 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 technology for the material handling units.

(h) 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.

Step 2 - Eliminate Technically Infeasible $PM_{2.5}$ Controls for the Material Handling

All of the identified control technologies are technically feasible for material handling.

Step 3 - Rank the Remaining $PM_{2.5}$ Control Technologies for the Material Handling

The following control technologies have been identified and ranked for control of particulates from the material handling equipment.

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

Step 4 - Evaluate the Most Effective Controls

Fort Wainwright BACT Proposal

Fort Wainwright proposes the following as BACT for $PM_{2.5}$ emissions from material handling based on a combination of manufacturing design and loading techniques:

(a) $PM_{2.5}$ emissions from the South Coal Handling Dust Collector (EU 7a) shall not exceed 0.0025 gr/dscf and shall be controlled by enclosed emission points and by following manufacturer's recommendations for operations and maintenance.

(b) $PM_{2.5}$ emissions from the South Underbunker, Fly Ash, and Bottom Ash Dust Collectors (EUs 7b, 7c, 51a, and 51b) shall not exceed 0.02 gr/dscf and shall be controlled by enclosed emission points and by following manufacturer's recommendations for operations and maintenance.

(c) $PM_{2.5}$ emissions from the North Coal Handling Dust Collector (EU 7c) shall not exceed 0.02 gr/dscf and shall be limited to no more than 200 hours per year.

(d) Initial compliance with the $PM_{2.5}$ emission limits, except the emission limit for EU 52, will be demonstrated by conducting a performance test to obtain an emission rate.

(e) $PM_{2.5}$ emissions from the Emergency Coal Storage Pile and Operations (EU 52) shall not exceed 1.42 tpy and shall be controlled with chemical stabilizers, wind fencing, covered haul vehicles, watering, and wind awareness. These procedures are identified in the September 2003 Fort Wainwright Dust Control Plan, prepared by the United States Army Center for Health Promotion and Preventive Medicine Alaskan Field Office in Conjunction with Oak Ridge Institute for Science and Education.

Step 5 - Selection of $PM_{2.5}$ BACT for the Material Handling Equipment

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 the material handling equipment shall be controlled by **operating the South and North Coal Handling Systems and the Underbunker Conveyors EUs 7a-7c, and the Fly and Bottom Ash Handling Systems EUs 51a and 51b, with enclosed conveying systems equipped with dust collectors** at all times the units are in operation;

(b) Comply with the numerical BACT emission limits listed in Table 4-12 for $PM_{2.5}$;

(c) $PM_{2.5}$ emissions from DU EU 52 shall not exceed 1.42 tpy. Continuous compliance with the $PM_{2.5}$ emissions limit shall be demonstrated by complying with the fugitive dust control plan identified in the applicable operating permit issued to the source in accordance with 18 AAC 50 and AS 46.14; and

(d) Compliance with the $PM_{2.5}$ emission rates for the material handling units shall be demonstrated by following the fugitive dust control plan and the manufacturer's operating and maintenance procedures at all times of operation.

Table 4-12. $PM_{2.5}$ BACT Control Technologies Proposed for Material Handling

EU ID	Description	Current Control	BACT Limit	Proposed BACT Control
7a	South Coal Handling Dust Collector	Partial Enclosure and Dust Collection	0.0025 gr/dscf	Enclosed emission points and follow manufacturer recommendations for operations and maintenance
7b	South Underbunker Dust Collector	Partial Enclosure and Dust Collection	0.02 gr/dscf	Enclosed emission points and follow manufacturer recommendations for operations and maintenance
7c	North Coal Handling Dust Collector	Partial Enclosure and Dust Collection	0.02 gr/dscf	**Enclosed emission points and** limited Operation – This source serves as backup to EU 7a and operates less than 200 hours each year
52	Emergency Coal Storage Pile and Operations	Follow Fugitive Dust Control Plan	Dust Control Plan[16]	Chemical Stabilizers, Wind Fencing, Covered Haul Vehicles, Watering, and Wind Awareness
51a	Fly Ash Dust Collector	Partial Enclosure and Dust Collection	0.02 gr/dscf	Enclosed emission points and follow manufacturer recommendations for operations and maintenance
51b	Bottom Ash Dust Collector	Partial Enclosure and Dust Collection	0.02 gr/dscf	Enclosed emission points and follow manufacturer recommendations for operations and maintenance

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.

[16] If technological or economic limitations in the application of a measurement methodology to a particular emission unit would make an emission limit infeasible, a design, equipment, work practice, operational standard or combination of thereof, may be prescribed.

5.1 SO_2 BACT for the Industrial Coal-Fired Boilers

Possible SO_2 emission control technologies for coal-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 for the coal-fired boilers 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, limestone injection, and low sulfur coal are the principle SO_2 control technologies installed on industrial coal-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 Coal-Fired Boilers
From research, the Department identified the following technologies as available for SO_2 control of industrial coal-fired boilers:

(a) Wet Scrubbers/Wet Flue Gas Desulfurization (WFGD)
Post combustion flue gas desulfurization techniques can remove SO_2 formed during combustion by using an alkaline reagent to absorb SO_2 in the flue gas. Flue gasses can be treated using wet, dry, or semi-dry desulfurization processes. 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. 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.

The lime and limestone wet scrubbing process uses a slurry of calcium oxide or limestone to absorb SO_2 in a wet scrubber. Control efficiencies in excess of 91 percent for lime and 94 percent for limestone over extended periods are possible. Sodium scrubbing processes generally employ a wet scrubbing solution of sodium hydroxide or sodium carbonate to absorb SO_2 from the flue gas. Sodium scrubbers are generally limited to smaller sources because of high reagent costs and can have SO_2 removal efficiencies of up to 96.2 percent. The double or dual alkali system uses a clear sodium alkali solution for SO_2 removal followed by a regeneration step using lime or limestone to recover the sodium alkali and produce a calcium sulfite and sulfate sludge. SO_2 removal efficiencies of 90 to 96 percent are possible. The Department considers flue gas desulfurization with a wet scrubber a technically feasible control technology for the industrial coal-fired boilers.

(b) Spray Dry Absorbers (SDA)

In SDA systems, an aqueous sorbent slurry with a higher sorbent ratio than that of a wet scrubber is injected into the hot flue gases. As the slurry mixes with the flue gas, the water is evaporated and the process forms a dry waste which is collected in a baghouse or electrostatic precipitator. The Department considers flue gas desulfurization with an SDA system a technically feasible control technology for the industrial coal-fired boilers.

(c) Dry Sorbent Injection (DSI)
Dry sorbent injection systems (spray dry scrubbers) pneumatically inject a powdered sorbent directly into the furnace, the economizer, or the downstream ductwork depending on the temperature and the type of sorbent utilized. The dry waste is removed using a baghouse or electrostatic precipitator. 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. Spray dry scrubbers are mostly used for small to medium capacity boilers and are preferable for retrofits. The Department considers flue gas desulfurization with a dry scrubber a technically feasible control technology for the industrial coal-fired boilers.

(d) Low Sulfur Coal
Fort Wainwright 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 feasible control technology for the industrial coal-fired boilers. **Because the Permittee already combusts low sulfur coal, this control option represents the baseline emissions rate, or a 0% emissions control.**

(e) Good Combustion Practices
The theory of GCPs was discussed in detail in the $PM_{2.5}$ BACT section for the industrial coal-fired boilers 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 industrial coal-fired boilers.

(f) Circulating Dry Scrubber (CDS)
This demonstrated technology can achieve SO_2 removal rates comparable to wet flue
gas desulfurization (FGD). CDS technology utilizes a dry circulating fluid bed and an ESP or Fabric Filter for utility scale flue gas desulfurization. CDS technology lends well for small footprints and adequate SO_2 removal. CDS technology is designed for relatively small installations with limited space and perform well with medium-high sulfur coals. The Department considers CDS a technically feasible control technology for the industrial coal-fired boilers.

Step 2 - Eliminate Technically Infeasible SO_2 Control Technologies for Coal-Fired Boilers
While all identified control devices have been determined technically feasible for the industrial coal-fired boilers, Doyon identified collateral environmental impact for wet systems, also given rise to safety concerns for the stationary source and surrounding community due to ice fog events. Doyon made reference to ice fog directly contributing to accidents on the neighboring highway and a crashed plane at a nearby airfield.

Step 3 - Rank the Remaining SO_2 Control Technologies for Industrial Coal-Fired Boilers
The following control technologies have been identified and ranked by efficiency for control of SO_2 emissions from the industrial coal-fired boilers:

(a)	Wet Scrubbers	(99% Control)
(f)	**Circulating Dry Scrubber**	**(99% Control)**
(b)	**Spray Dry Absorbers (SDA)**	**(95% Control)**
(c)	**Dry Sorbent Injection (Duct Sorbent Injection)**	**(93+% Control)**
(e)	Good Combustion Practices	(Less than 40% Control)
(d)	Low Sulfur Coal	(**0% Control, Baseline**)

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

Fort Wainwright BACT Proposal

DU provided an updated economic analysis from Black and Veatch on November 13, 2023, for the installation of WFGD (caustic and limestone), SDA, CDS, and DSI control technology systems. This updated analysis also included new removal efficiencies for DSI based on information from BACT Process Systems, LLC and United Conveyor, LLC. DU's analysis now assumes a 93% removal rate for DSI, which matches the highest efficiency in their analyses for WFGD, and is higher than the removal efficiency for the more expensive CDS and SDA control systems. A summary of the analysis is shown below:

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

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annual Costs ($/year)	Cost Effectiveness ($/ton)
WFGD - Caustic	101	1369	110,262,000	18,832,000	13,755
WFGD - limestone	101	1369	126,374,000	19,474,000	14,224
Spray-Dry Adsorption	176	1293	166,101,000	22,812,000	17,638
CDS	176	1293	196,447,000	27,096,000	20,950
Dry Sorbent Injection[17]	101	1369	28,424,000	9,082,000	6,636

[17] Calculated using Amerair Industries Proposal for 80% removal of SO_2 emissions.

Control Alternative	**Potential to Emit (tpy)**	**Emission Reduction (tpy)**	**Total Capital Investment ($)**	**Total Annual Costs ($/year)**	**Cost Effectiveness ($/ton)**
Capital Recovery Factor = 0.0931 (8.5% interest rate for a 30-year equipment life)					

Fort Wainwright contends that the economic analysis indicates the level of SO_2 reduction does not justify the use of WFGD, CDS, or SDA for the coal-fired boilers based on the excessive cost per ton of SO_2 removed per year compared to DSI.

Fort Wainwright proposes the following as BACT for SO_2 emissions from the coal-fired boilers:

(a) SO_2 emissions from the operation of the coal-fired boilers will be controlled by limited operation, good combustion practices, and low sulfur fuel at all times the boilers are in operation.

(b) SO_2 emissions from the coal-fired boilers will be controlled by burning low sulfur coal at all times the boilers are in operation.

(c) SO_2 emissions from the coal-fired boilers will not exceed 0.49 lb/MMBtu.

(d) SO_2 emissions from the coal-fired boilers will be controlled by limiting the allowable coal combustion to no more than **336**,000 tons per year.

(e) Initial compliance with the proposed SO_2 emission limit will be demonstrated by conducting a performance test to obtain an emission rate.

Department Evaluation of BACT for SO_2 Emissions from the Industrial Coal-Fired Boilers
The Department did not revise the cost analysis provided on November 13, 2023 by DU because we find that the economic analysis conducted by Black & Veatch is reasonable to determine cost effectiveness of each potential technology for SO_2 Emissions reduction. It is possible that costs for an individual control technology could be slightly lower or higher, but that would not change the overall finding that DSI with a 93% SO_2 removal rate is cost effective and the other control technologies will cost substantially more while returning little to no added reductions of SO_2. Table 5-2 above is repeated below:

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

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annual Costs ($/year)	Cost Effectiveness ($/ton)
WFGD - Caustic	101	1369	110,262,000	18,832,000	13,755
WFGD - limestone	101	1369	126,374,000	19,474,000	14,224
Spray-Dry Adsorption	176	1293	166,101,000	22,812,000	17,638
CDS	176	1293	196,447,000	27,096,000	20,950
Dry Sorbent Injection[18]	101	1369	28,424,000	9,082,000	6,636

[18] Calculated using Amerair Industries Proposal for 80% removal of SO_2 emissions.

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annual Costs ($/year)	Cost Effectiveness ($/ton)
Capital Recovery Factor = 0.0931 (8.5% interest rate for a 30-year equipment life)					

The economic analysis indicates that level of SO_2 reduction justifies the use of dry sorbent injection as BACT for the coal-fired boilers located in the Serious $PM_{2.5}$ nonattainment area.

Step 5 - Selection of SO_2 BACT for the Industrial Coal-Fired Boilers

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

(a) SO_2 emissions from DU EUs 1 through 6 shall be controlled by operating and maintaining dry sorbent injection at all times the units are in operation;

(b) SO_2 emissions from DU EUs 1 through 6 shall not exceed 0.04 lb/MMBtu[19] averaged over a 3-hour period;

(c) Limit the combined coal combustion in DU EUs 1 through 6 to no more than 336,000 tons per year; and

(d) Initial compliance with the SO_2 emission rate for the coal-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[20]
Fort Wainwright	6 Coal-Fired Boilers	1380 MMBtu/hr (combined)	0.04 lb/MMBtu[19]	Dry Sorbent Injection Limited Operation
UAF	Dual Fuel-Fired Boiler	295.6 MMBtu/hr	0.10 lb/MMBtu[21]	**Fluidized Bed** Limestone Injection
Chena	4 Coal-Fired Boilers	497 MMBtu/hr (combined)	**0.301 lb/MMBtu**[22]	**Good Combustion Practices**

5.2 SO_2 BACT for the Diesel-Fired Boilers

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

[19] **BACT limit is a vendor emissions guarantee.**

[20] **Note that the Department removed the reference to low sulfur coal, which was never selected as part of the top down BACT determination process and is already the only type of coal available to sources in Alaska.**

[21] The Department selected the UAF BACT SO_2 emissions limit using a statistical analysis of historical CEMS emissions data.

[22] **BACT limit is the average emissions rate from two recent SO_2 source test accepted by the Department, which occurred on November 19, 2011 and July 12, 2019.**

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

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

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Low Sulfur Fuel	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 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 Diesel-Fired Boilers
From research, the Department identified the following technologies as available for control of SO_2 emissions from 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 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 control 99 percent of SO_2 emissions from the diesel-fired boilers. The Department considers ULSD a technically feasible control technology for the diesel-fired boilers.

(b) Limited Operation
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 diesel-fired boilers.

(c) Good Combustion Practices
The theory of GCPs was discussed in detail in the $PM_{2.5}$ BACT section for the coal-fired boilers 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 diesel-fired boilers.

Step 2 - Eliminate Technically Infeasible SO_2 Control Technologies for the 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 Diesel-Fired Boilers
The following control technologies have been identified and ranked by efficiency for the control of SO_2 emissions from the diesel-fired boilers:

(a) Ultra Low Sulfur Diesel (99% Control)
(b) Limited Operation (94% Control)
(c) Good Combustion Practices (Less than 40% Control)

Step 4 - Evaluate the Most Effective Controls

Fort Wainwright BACT Proposal

Fort Wainwright proposes the following as BACT for SO_2 emissions from the diesel-fired boilers:

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

(b) Combined operating limit of 600 hours per year for FWA EUs 8, 9, and 10; and

(c) Combust only ULSD.

Department Evaluation of BACT for SO_2 Emissions from Diesel-Fired Boilers

The Department reviewed Fort Wainwright's proposal and finds that the **four significant sized boilers**[23] have a combined PTE of less than 9 tpy for SO_2 using the conservative assumption of 0.3 percent sulfur by weight in fuel oil. Fort Wainwright proposed combusting only ULSD in all the boilers, therefore an economic analysis is not required.

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

The Department's finding is that BACT for SO_2 emissions from the diesel-fired boilers **EUs 8 – 10 and 40** is as follows:

(a) SO_2 emissions from the diesel-fired boilers **EUs 8 – 10 and 40** shall be controlled by only combusting ULSD;

(b) Combined operating limit of 600 hours per year for FWA EUs 8, 9, and 10; and

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

Table 5-6 lists the proposed SO_2 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 5-6. Comparison of SO_2 BACT for the Diesel-Fired Boilers at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
Fort Wainwright	**4** Diesel-Fired Boilers	< 100 MMBtu/hr	15 ppmw S in fuel	Good Combustion Practices Ultra-Low Sulfur Diesel
UAF	**6** Diesel-Fired Boilers	< 100 MMBtu/hr	15 ppmw S in fuel	Good Combustion Practices 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

[23] **The Department's revised BACT finding for the diesel-fired boilers removes the insignificant boilers that are associated with Fort Wainwright. The Department notes that no other insignificant boilers from other sources were originally included in the BACT analyses and that the insignificant emissions units will have to meet the BACM requirements under 18 AAC 50.078, which includes the requirement to combust fuel oil that contains no more than 1,000 ppmw sulfur.**

5.3 SO_2 BACT for the Large Diesel-Fired Engines, Fire Pumps, and Generators

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 to 17.190, Large Internal Combustion Engines (>500 hp). The search results for large diesel-fired engines are summarized in Table 5-7.

Table 5-7. RBLC Summary 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, good combustion practices, and compliance with the federal emission standards are the principle SO_2 control technologies installed on large diesel-fired engines. The lowest SO_2 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 Engines
From research, the Department identified the following technologies as available for control of SO_2 emissions from diesel-fired engines rated at 500 hp or greater:

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

(b) Federal Emission Standards
RBLC 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.. The Department considers meeting the technology based NSPS of Subpart IIII as a technically feasible control technology for the large diesel-fired engines.

(c) Limited Operation
FWA EUs 11, 12, and 13 currently operate under a combined annual limit of less than 600 hours per year to avoid classification as a PSD major modification for NOx. 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 large diesel-fired engines.

(d) Good Combustion Practices

The theory of GCPs was discussed in detail in the $PM_{2.5}$ BACT section for the coal-fired boilers 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 engines.

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

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

(a)	Ultra Low Sulfur Diesel	(99% Control)
(c)	Limited Operation	(94% Control)
(d)	Good Combustion Practices	(Less than 40% Control)
(b)	Federal Emission Standards	(Baseline)

Step 4 - Evaluate the Most Effective Controls

Fort Wainwright BACT Proposal

Fort Wainwright proposes the following as BACT for SO_2 emissions from the large diesel-fired engines:

(a) Combined operating limit of 600 hours per year for FWA EUs 11, 12, and 13; and

(b) SO_2 emissions from the operation of the large diesel-fired engines shall be controlled with combustion of ultra-low sulfur diesel.

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

The Department reviewed Fort Wainwright's proposal and finds that SO_2 emissions from the large diesel-fired engines can additionally be controlled by limiting the use of the units during non-emergency operation.

Step 5 - Selection of SO_2 BACT for the Large Diesel-Fired Engines
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 DU EU 8, and FWA EUs 11, 12, 13, and 50 through 54 shall be controlled by only combusting ULSD;

(b) Limit DU EU 8 to 500 hours per year;

(c) Combined operating limit of 600 hours per year for FWA EUs 11, 12, and 13;

(d) Limit non-emergency operation of FWA EUs 50 through 54 to no more than 100 hours per year; and

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

Table 5-8 lists the proposed SO_2 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 5-8. 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	500 ppmw S in fuel	Good Combustion Practices Ultra-Low Sulfur Diesel
GVEA Zehnder	2 Large Diesel-Fired Engines	11,000 hp	15 ppmw S in fuel	Good Combustion Practices Ultra-Low Sulfur Diesel

5.4 SO_2 BACT for the Small Emergency Engines, Fire Pumps, and Generators

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 5-9.

Table 5-9. RBLC Summary for SO_2 Control 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 section for the small 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
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 engines.

(c) Good Combustion Practices
The theory of GCPs was discussed in detail in the $PM_{2.5}$ BACT section for the coal-fired boilers 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)
(b) Limited Operation (94% Control)
(c) Good Combustion Practices (Less than 40% Control)

Step 4 - Evaluate the Most Effective Controls

Fort Wainwright BACT Proposal

Fort Wainwright proposes the following as BACT for SO_2 emissions from the small diesel-fired engines:
(a) Good Combustion Practices;
(b) Combust only ULSD.

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

The Department reviewed Fort Wainwright's proposal and found that in addition to maintaining good combustion practices and combusting only ULSD, limiting operation of the small diesel-fired engines during non-emergency operation to no more than 100 hours per year each 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) Limit non-emergency operation of DU EUs 9, 14, 22, 23, 29a, **30a,** 31a, **32a, 33a, 34, 35a, 36, 37a,** FWA EUs 26 through 39, 52, and 55 through **69** to no more than 100 hours per year each;

(b) Combust only ULSD; and

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

Table 5_{10} lists the proposed SO_2 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 510. Comparison of SO_2 BACT for Small Diesel-Fired Engines at Nearby Power Plants

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

6. BACT DETERMINATION SUMMARY

Table 6-1. Proposed NOx BACT Limits

EU ID	Description	Capacity	Proposed BACT Limit	Method of Compliance Demonstration	Proposed BACT Control
All	**N/A**	**N/A**	**None EPA approved a comprehensive precursor demonstration for NOx See details in the Section 1 Introduction**		

Table 6-2. Proposed $PM_{2.5}$ BACT Limits

EU ID	Description	Capacity	Proposed BACT Limit	Time Average / Method of Compliance	Proposed BACT Control
DU 1	Six Coal Fired Boiler 3	230 MMBtu/hr	0.045 lb/MMBtu	**Compliance with NESHAP DDDDD applicable PM emission standards**	Full stream baghouse **Good Combustion Practices**
DU 2	Six Coal Fired Boiler 4	230 MMBtu/hr	0.045 lb/MMBtu		
DU 3	Six Coal Fired Boiler 5	230 MMBtu/hr	0.045 lb/MMBtu		
DU 4	Six Coal Fired Boiler 6	230 MMBtu/hr	0.045 lb/MMBtu		
DU 5	Six Coal Fired Boiler 7	230 MMBtu/hr	0.045 lb/MMBtu		
DU 6	Six Coal Fired Boiler 8	230 MMBtu/hr	0.045 lb/MMBtu		
FWA 8	Backup Diesel-Fired Boiler 1	19 MMBtu/hr	**0.016** lb/MMBtu	**Compliance with NESHAP DDDDD applicable emission standards**	Good Combustion Practices Limited Operation (600 hours/year combined)
FWA 9	Backup Diesel-Fired Boiler 2	19 MMBtu/hr	**0.016** lb/MMBtu		
FWA 10	Backup Diesel-Fired Boiler 3	19 MMBtu/hr	**0.016** lb/MMBtu		
FWA 40	**Diesel-Fired Boiler**	**2.6 MMBtu/hr**	**0.016 lb/MMBtu**		Good Combustion Practices
DU 8	**Generator Engine**	**2,937 hp**	**0.15 g/hp-hr**	**NSPS Subpart IIII**	Combust ULSD Good Combustion Practices Limited Operation (500 hours/yr)
FWA 50	Generator Engine	762 hp	0.15 g/hp-hr		
FWA 51	Generator Engine	762 hp	0.15 g/hp-hr		

EU ID	Description	Capacity	Proposed BACT Limit	Time Average / Method of Compliance	Proposed BACT Control
FWA 53	**Generator Engine**	**587 hp**	**0.15 g/hp-hr**	**NSPS Subpart IIII, NESHAP Subpart ZZZZ, tracking hours of operation, and Good Air Pollution Control permit condition**	Limited Operation (100 hours/year, for non-emergency operation) Good Combustion Practices
FWA 54	Generator Engine	1,059 hp	0.32 g/hp-hr		
FWA 11	Caterpillar 3512	1,206 hp	0.32 g/hp-hr		Limit Operation (600 hours/year combined) Combust ULSD Good Combustion Practices
FWA 12	Caterpillar 3512	1,206 hp	0.32 g/hp-hr		
FWA 13	Caterpillar 3512	1,206 hp	0.32 g/hp-hr		
DU 9	Generator Engine	353 hp	2.20 E-3 lb/hp-hr		Limited Operation (50 hours/year each, for non-emergency operation) Good Combustion Practices Combust ULSD
DU 14	Generator Engine	320 hp	0.2 g/kW-hr		
DU 22	Generator Engine	35 hp	2.20 E-3 lb/hp-hr		
DU 23	Generator Engine	155 hp	2.20 E-3 lb/hp-hr		
FWA 52	Generator Engine	82 hp	2.20 E-3 lb/hp-hr		
FWA 55	Generator Engine	212 hp	2.20 E-3 lb/hp-hr		
FWA 56	Generator Engine	176 hp	0.40 g/hp-hr		
FWA 57	Generator Engine	212 hp	2.20 E-3 lb/hp-hr		
FWA 58	Generator Engine	71 hp	0.4 g/kW-hr		
FWA 59	Generator Engine	35 hp	2.20 E-3 lb/hp-hr		
FWA **60a**	Generator Engine	**230 hp**	**0.2** g/kW-hr		
FWA 61	Generator Engine	50 hp	2.20 E-3 lb/hp-hr		
FWA 62	Generator Engine	18 hp	0.4 g/kW-hr		
FWA 63	Generator Engine	68 hp	2.20 E-3 lb/hp-hr		
FWA 64	Generator Engine	274 hp	0.2 g/kW-hr		
FWA 65	Generator Engine	274 hp	0.2 g/kW-hr		
FWA 66	**Generator Engine**	**235 hp**	**0.2 g/kW-hr**		
FWA 67	**Generator Engine**	**67 hp**	**0.4 g/kW-hr**		
FWA 68	**Generator Engine**	**324 hp**	**0.2 g/kW-hr**		
FWA 69	**Generator Engine**	**86 hp**	**0.4 g/kW-hr**		

EU ID	Description	Capacity	Proposed BACT Limit	Time Average / Method of Compliance	Proposed BACT Control
DU 34	Well Pump Engine	220 hp	2.20 E-3 lb/hp-hr		
DU 35	Well Pump Engine	55 hp	0.3 g/hp-hr		
DU 36	Well Pump Engine	220 hp	2.20 E-3 lb/hp-hr		
DU 29a	Lift Pump Engine	74 hp	0.3 g/kW-hr		
DU 30a	**Lift Pump Engine**	**80 hp**	**0.3 g/kW-hr**		
DU 31a	Lift Pump Engine	74 hp	0.3 g/kW-hr		
DU 32a	**Lift Pump Engine**	**80 hp**	**0.3 g/kW-hr**		
DU 33a	**Lift Pump Engine**	**75 hp**	**0.3 g/kW-hr**		
DU 37a	**Lift Pump Engine**	**75 hp**	**0.3 g/kW-hr**		
FWA 26	QSB7-G3 NR3	295 hp	0.02 g/kW-hr		
FWA 27	4024HF285B	67 hp	0.3 g/kW-hr		
FWA 28	CAT C9 GENSET	398 hp	0.2 g/kW-hr		
FWA 29	TM30UCM	47 hp	2.20 E-3 lb/hp-hr		
FWA 30	JW64-UF30	275 hp	0.2 g/kW-hr		
FWA 31	DDFP-04AT	235 hp	2.20 E-3 lb/hp-hr		
FWA 32	DDFP-04AT	235 hp	2.20 E-3 lb/hp-hr		
FWA 33	DDFP-04AT	235 hp	2.20 E-3 lb/hp-hr		Limited Operation (100 hours/year each, for non-emergency operation) Good Combustion Practices Combust ULSD
FWA 34	DDFP-04AT	235 hp	2.20 E-3 lb/hp-hr		
FWA 35	N-855-F	240 hp	2.20 E-3 lb/hp-hr		
FWA 36	N-855-F	240 hp	2.20 E-3 lb/hp-hr		
FWA 37	JU4H-UF40	105 hp	2.20 E-3 lb/hp-hr		
FWA 38	PDFP-06YT	120 hp	2.20 E-3 lb/hp-hr		
FWA 39	PDFP-06YT	120 hp	2.20 E-3 lb/hp-hr		

Table 6-3. Proposed $PM_{2.5}$ BACT Limits for Material Handling Equipment

EU ID	Description	Proposed BACT Limit	Method of Compliance	Proposed BACT Control
7a	South Coal Handling Dust Collector	0.0025 gr/dscf	**Comply with NSPS Subpart Y and State opacity standards, and**	Enclosed emission points and follow manufacturer recommendations for operations and maintenance

			good pollution control practices	
7b	South Underbunker Dust Collector	0.02 gr/dscf	**Comply with NSPS Subpart Y and State opacity standards, and good pollution control practices**	Enclosed emission points and follow manufacturer recommendations for operations and maintenance
7c	North Coal Handling Dust Collector	0.02 gr/dscf	**Comply with NSPS Subpart Y and State opacity standards, and good pollution control practices**	Limited Operation – This source serves as backup to EU 7a and operates less than 200 hours each year
52	Emergency Coal Storage Pile and Operations	Varies	**Comply fugitive dust control plan implementation**	Chemical Stabilizers, Wind Fencing, Covered Haul Vehicles, Watering, and Wind Awareness
51a	Fly Ash Dust Collector	0.02 gr/dscf	**Comply with good pollution control practices**	Enclosed emission points and follow manufacturer recommendations for operations and maintenance
51b	Bottom Ash Dust Collector	0.02 gr/dscf	**Comply with good pollution control practices**	Enclosed emission points and follow manufacturer recommendations for operations and maintenance

Table 6-4. Proposed SO_2 BACT Limits

EU ID	Description	Capacity	Proposed BACT Limit	Time Average / Method of Compliance Demostration	Proposed BACT Control
DU 1	Six Coal Fired Boiler 3	230 MMBtu/hr	**0.04** lb/MMBtu	**3-hr average / EPA Method 7E**	Dry Sorbent Injection[20] Limited Operation (336,000 tons/year combined)
DU 2	Six Coal Fired Boiler 4	230 MMBtu/hr	**0.04** lb/MMBtu		
DU 3	Six Coal Fired Boiler 5	230 MMBtu/hr	**0.04** lb/MMBtu		
DU 4	Six Coal Fired Boiler 6	230 MMBtu/hr	**0.04** lb/MMBtu		
DU 5	Six Coal Fired Boiler 7	230 MMBtu/hr	**0.04** lb/MMBtu		
DU 6	Six Coal Fired Boiler 8	230 MMBtu/hr	**0.04** lb/MMBtu		
FWA 8	Backup Diesel-Fired Boiler 1	19 MMBtu/hr	15 ppmv S in fuel	**Per fuel delivery / Track fuel receipts**	Good Combustion Practices Limited Operation (600 hours/year combined) Combust ULSD
FWA 9	Backup Diesel-Fired Boiler 2	19 MMBtu/hr	15 ppmv S in fuel		
FWA 10	Backup Diesel-Fired Boiler 3	19 MMBtu/hr	15 ppmv S in fuel		
FWA 40	**Diesel-Fired Boiler**	**2.6 MMBtu/hr**	**15 ppmv S in fuel**		Good Combustion Practices Combust ULSD
DU 8	Generator Engine	2,937 hp	15 ppmv S in fuel		Limited Operation (100 hours/year each, for non-emergency operation)
FWA 50	Generator Engine	762 hp	15 ppmv S in fuel		
FWA 51	Generator Engine	762 hp	15 ppmv S in fuel		
FWA 53	**Generator Engine**	**587 hp**	**0.15 g/hp-hr**		
FWA 54	**Generator Engine**	**1,059 hp**	**0.32 g/hp-hr**		
FWA 11	Caterpillar 3512	1,206 hp	15 ppmv S in fuel		Limit Operation (600 hours/year combined) Combust ULSD Good Combustion Practices
FWA 12	Caterpillar 3512	1,206 hp	15 ppmv S in fuel		
FWA 13	Caterpillar 3512	1,206 hp	15 ppmv S in fuel		
DU 9	Generator Engine	353 hp	15 ppmv S in fuel		Limited Operation (100 hours/year each, for non-emergency operation) Good Combustion Practices
DU 14	Generator Engine	320 hp	15 ppmv S in fuel		
DU 22	Generator Engine	35 hp	15 ppmv S in fuel		
DU 23	Generator Engine	155 hp	15 ppmv S in fuel		

EU ID	Description	Capacity	Proposed BACT Limit	Time Average / Method of Compliance Demostration	Proposed BACT Control
FWA 52	Generator Engine	82 hp	15 ppmv S in fuel		Combust ULSD
FWA 55	Generator Engine	212 hp	15 ppmv S in fuel		
FWA 56	Generator Engine	176 hp	15 ppmv S in fuel		
FWA 57	Generator Engine	212 hp	15 ppmv S in fuel		
FWA 58	Generator Engine	71 hp	15 ppmv S in fuel		
FWA 59	Generator Engine	35 hp	15 ppmv S in fuel		
FWA **60a**	Generator Engine	**230** hp	15 ppmv S in fuel		
FWA 61	Generator Engine	50 hp	15 ppmv S in fuel		
FWA 62	Generator Engine	18 hp	15 ppmv S in fuel		
FWA 63	Generator Engine	68 hp	15 ppmv S in fuel		
FWA 64	Generator Engine	274 hp	15 ppmv S in fuel		
FWA 65	Generator Engine	274 hp	15 ppmv S in fuel		
FWA 66	**Generator Engine**	**235 hp**	**15 ppmv S in fuel**		
FWA 67	**Generator Engine**	**67 hp**	**15 ppmv S in fuel**		
FWA 68	**Generator Engine**	**324 hp**	**15 ppmv S in fuel**		
FWA 69	**Generator Engine**	**86 hp**	**15 ppmv S in fuel**		
DU 34	Well Pump Engine	220 hp	15 ppmv S in fuel		
DU 35	Well Pump Engine	55 hp	15 ppmv S in fuel		
DU 36	Well Pump Engine	220 hp	15 ppmv S in fuel		
DU 29a	Lift Pump Engine	74 hp	15 ppmv S in fuel		
DU 30a	**Lift Pump Engine**	**80 hp**	**15 ppmv S in fuel**		
DU 31a	Lift Pump Engine	74 hp	15 ppmv S in fuel		
DU 32a	**Lift Pump Engine**	**80 hp**	**15 ppmv S in fuel**		
DU 33a	**Lift Pump Engine**	**75 hp**	**15 ppmv S in fuel**		
DU 37a	**Lift Pump Engine**	**75 hp**	**15 ppmv S in fuel**		
FWA 26	QSB7-G3 NR3	295 hp	15 ppmv S in fuel		
FWA 27	4024HF285B	67 hp	15 ppmv S in fuel		
FWA 28	CAT C9 GENSET	398 hp	15 ppmv S in fuel		
FWA 29	TM30UCM	47 hp	15 ppmv S in fuel		
FWA 30	JW64-UF30	275 hp	15 ppmv S in fuel		

EU ID	Description	Capacity	Proposed BACT Limit	Time Average / Method of Compliance Demostration	Proposed BACT Control
FWA 31	DDFP-04AT	235 hp	15 ppmv S in fuel		
FWA 32	DDFP-04AT	235 hp	15 ppmv S in fuel		
FWA 33	DDFP-04AT	235 hp	15 ppmv S in fuel		
FWA 34	DDFP-04AT	235 hp	15 ppmv S in fuel		
FWA 35	N-855-F	240 hp	15 ppmv S in fuel		
FWA 36	N-855-F	240 hp	15 ppmv S in fuel		
FWA 37	JU4H-UF40	105 hp	15 ppmv S in fuel		
FWA 38	PDFP-06YT	120 hp	15 ppmv S in fuel		
FWA 39	PDFP-06YT	120 hp	15 ppmv S in fuel		

Stationary Source: Fort Wainwright – Doyon Utilities (DU) and US Army (FWA)

Emission Units: DU EU IDs 1, 2, 3, 4, 5 and 6 (230 MMBtu/hr – Coal Boilers)

Pollutant of Concern: $PM_{2.5}$	
BACT Measure	**Monitoring, Recordkeeping and Reporting Requirements** [1]
0.045 lb/MMBtu (3-hr avg);	• Conduct a one-time performance test using EPA Method 201A and 202 at maximum load to demonstrate compliance and submit results to the Department. • Report source test results as required by Operating Permit.
Use of full stream baghouse at all times the boilers are in operation	• Certify in Facility Operating Report that full stream baghouse is operated at all times the boilers are in operation. • Operate, inspect, and maintain the baghouses according to the manufacturer's instructions and recommendations. • Include a summary of inspection and maintenance conducted in each semi-annual operating report.
Good Combustion Practices	• Keep records of maintenance conducted on emission units to comply with this BACT measure. • Keep a copy of the manufacturer's and the operator's recommended maintenance procedures.
Maintain compliance with State opacity standards listed under 50.055(a)(9)	• Monitor, record, and report visible emissions using Continuous Opacity Monitoring System (COMS) installed and maintained as directed in the corresponding Operating Permit.

Emission Units: FWA EU IDs 8 – 10 (19 MMBtu/hr) and 40 (2.6 MMBtu/hr) Diesel-Fired Boilers

Pollutant of Concern: $PM_{2.5}$	
BACT Measure	**Monitoring, Recordkeeping and Reporting Requirements** [1]
0.016 lb/MMBtu (3-hr avg); Good Combustion Practices	• Keep records of maintenance conducted on emission units to comply with this BACT measure. • Keep a copy of the manufacturer's and operator's recommended maintenance procedures. • Comply with the boiler tune-up procedures and MR&R requirements in NESHAP Subpart DDDDD.
Combined operating limit of 600 hours per year for FWA EUs 8, 9, and 10	• Demonstration compliance by complying with Condition 5.2 of Minor Permit AQ0236MSS02.

[1] While the substantive requirements are described here, for any permit containing the requirement, the actual language may differ in non-substantive ways and include additional details.

Emission Units: DU EU IDs 8 (Large Diesel – Fired Engine 2,937 hp) and FWA EU IDs 50, 51, 53 (Large Diesel – Fired Engine 762, 762, and 587 hp respectively)

Pollutant of Concern: $PM_{2.5}$	
BACT Measure	**Monitoring, Recordkeeping and Reporting Requirements [1]**
0.15 g/hp-hr	• For DU EU ID 8 and FWA IDs 50 and 51, report compliance with maintenance requirements under 40 CFR 60 Subpart IIII. • For FWA EU ID 53, demonstrate compliance by complying with the Good Air Pollution Control Practice Condition 70 in Operating Permit AQ0236TVP04.
Good Combustion Practices	• For DU EU ID 8 and FWA IDs 50 and 51, report compliance with maintenance requirements under 40 CFR 60 Subpart IIII. • For FWA EU ID 53, demonstrate compliance by complying with the Good Air Pollution Control Practice Condition 70 in Operating Permit AQ0236TVP04.
Limit DU EU 8 to 500 hours/yr Limit non-emergency operation of FWA EUs 50, 51, and 53 to 100 hours/yr each	• For DU EU ID 8: Demonstrate compliance by complying with Condition 2 of Minor Permit AQ1121MS02. • For FWA EU IDs 50 and 51, demonstrate compliance by complying with the NSPS Subpart IIII emergency engine requirements listed in 40 CFR 4211(f). • For FWA EU ID 53, demonstrate compliance by monitoring the engine's operating hours and reporting in the operating report.

Emission Units: FWA EU IDs 11, 12, 13 (Large Diesel – Fired Engines 1,206 hp)

Pollutant of Concern: $PM_{2.5}$	
BACT Measure	**Monitoring, Recordkeeping and Reporting Requirements [1]**
0.32 g/hp-hr	• Demonstrate compliance by complying with the Good Air Pollution Control Practice Condition 70 in Operating Permit AQ0236TVP04.
Good Combustion Practices	• Demonstrate compliance by complying with the Good Air Pollution Control Practice Condition 70 in Operating Permit AQ0236TVP04.
Combined operating limit of 600 hours per year for FWA EUs 11, 12, and 13	• Demonstration compliance by complying with Conditions 5.3 of Minor Permit AQ0236MSS02.

Emission Units: FWA EU IDs 54 (Large Diesel-Fired Engines 1,059 hp)

Pollutant of Concern: $PM_{2.5}$	
BACT Measure	**Monitoring, Recordkeeping and Reporting Requirements [1]**
0.32 g/hp-hr	• Report a list of repairs and maintenance conducted during each semiannual period along with Facility Operating Reports. • Certify following good combustion practices in each Facility Operating Report.
Good Combustion Practices	• Demonstrate compliance by complying with the Good Air Pollution Control Practice Condition 70 in Operating Permit AQ0236TVP04.

Operating limit of 100 hours per year each for non-emergency operation	• Demonstrate compliance by monitoring the engine's operating hours and reporting in the operating report.

Emission Units: EU IDs DU: 9, 22, 23, 34, 36 ; FWA: 29, 31, 32, 33, 34, 35, 36, 37, 38, 39, 52, 55, 57, 59, 61, 63 (Small Diesel-Fired Engines <500 hp)

Pollutant of Concern: $PM_{2.5}$	
BACT Measure	**Monitoring, Recordkeeping and Reporting Requirements [1]**
2.2 E-3 lb/hp-hr Combust only ULSD Good Combustion Practices Limit of 100 hours per year each for non-emergency operation	• Monitor operation of non-emergency use to ensure a limit of 100 hours per year each per engine. • Certify following good combustion practices in each Facility Operating Report. • Report fuel amount and type in each corresponding Facility Operating Report.

Emission Units: EU IDs DU: 14; FWA: 26, 28, 30, 60a, 64, 65, 66, and 68 (Small Diesel-Fired Engines <500 hp)

Pollutant of Concern: $PM_{2.5}$	
BACT Measure	**Monitoring, Recordkeeping and Reporting Requirements [1]**
0.2 g/kW-hr Combust only ULSD Good Combustion Practices Limit of 100 hours per year each for non-emergency operation	• Monitor operation of non-emergency use to ensure a limit of 100 hours per year each per engine. • Certify following good combustion practices in each Facility Operating Report. • Report fuel amount and type in each corresponding Facility Operating Report.

Emission Units: EU IDs DU 29a, 30a, 31a, 32a, 33a, 35, 37a; FWA: None (Small Diesel-Fired Engines <500 hp)

Pollutant of Concern: $PM_{2.5}$	
BACT Measure	**Monitoring, Recordkeeping and Reporting Requirements [1]**
0.3 g/hp-hr Good Combustion Practices	• Monitor operation of non-emergency use to ensure a limit of 100 hours per year each per engine. • Certify following good combustion practices in each Facility Operating Report.

Combust only ULSD Limit of 100 hours per year each for non-emergency operation	• Report fuel amount and type in each corresponding Facility Operating Report.

Emission Units: EU IDs DU: None; FWA: 27 (Small Diesel-Fired Engines <500 hp)

Pollutant of Concern: $PM_{2.5}$	
BACT Measure	**Monitoring, Recordkeeping and Reporting Requirements** [1]
0.3 g/kW-hr Good Combustion Practices Combust only ULSD Limit of 100 hours per year each for non-emergency operation	• Monitor operation of non-emergency use to ensure a limit of 100 hours per year each per engine. • Certify following good combustion practices in each Facility Operating Report. • Report fuel amount and type in each corresponding Facility Operating Report.

Emission Units: EU IDs DU: None; FWA: 56 (Small Diesel-Fired Engines <500 hp)

Pollutant of Concern: $PM_{2.5}$	
BACT Measure	**Monitoring, Recordkeeping and Reporting Requirements** [1]
0.4 g/hp-hr Good Combustion Practices Combust only ULSD Limit of 100 hours per year each for non-emergency operation	• Monitor operation of non-emergency use to ensure a limit of 100 hours per year each per engine. • Certify following good combustion practices in each Facility Operating Report. • Report fuel amount and type in each corresponding Facility Operating Report.

Emission Units: EU IDs DU: None; FWA: 58, 62, 67, and 69 (Small Diesel-Fired Engines <500 hp)

Pollutant of Concern: $PM_{2.5}$	
BACT Measure	**Monitoring, Recordkeeping and Reporting Requirements** [1]
0.4 g/kW-hr Good Combustion Practices Combust only ULSD	• Monitor operation of non-emergency use to ensure a limit of 100 hours per year each per engine. • Certify following good combustion practices in each Facility Operating Report. • Report fuel amount and type in each corresponding Facility Operating Report.

Limit of 100 hours per year each for non-emergency operation	

Emission Units: EU IDs DU: 7a (South Coal Handling Dust Collector)

Pollutant of Concern: $PM_{2.5}$	
BACT Measure	**Monitoring, Recordkeeping and Reporting Requirements** [1]
0.0025 gr/dscf Dust Collector and enclosed coal handling systems	• Monitor that the dust collector is operating when the south coal handling system is in operation. • Monitor that manufacturer's operating and maintenance procedures for the dust collector are followed. Maintain records of maintenance conducted, and report summaries of such maintenance in each Facility Operating Report. • Submit an initial compliance certification indicating that coal handling and conveying systems are enclosed. • Monitor that door(s) and access panels to coal handling and conveying systems are closed while in operation. • Keep records identifying each time that the EU is operated outside a required enclosure. • Report as a permit deviation whenever the south coal handling system is operated without a dust Collector and/or required enclosures.

Emission Units: EU IDs DU: 7b and 7c (South Under Bunker and North Coal Handling Dust Collectors)

Pollutant of Concern: $PM_{2.5}$	
BACT Measure	**Monitoring, Recordkeeping and Reporting Requirements** [1]
0.02 gr/dscf Dust Collectors and enclosed coal handling systems	• Monitor that the dust collectors are operating when the South Under Bunker Flight Conveyor and North Coal Handling systems are in operation. • Monitor that manufacturer's operating and maintenance procedures for the dust collector are followed. Maintain records of maintenance conducted, and report summaries of such maintenance in each Facility Operating Report. • Submit an initial compliance certification indicating that coal handling and conveying systems are enclosed. • Monitor that door(s) and access panels to coal handling and conveying systems are closed while in operation. • Keep records identifying each time that the EU(s) are operated without the dust collection systems or outside a required enclosure(s). • Report as a permit deviation whenever either the south under bunker flight conveyor or North Coal Handling systems are operated without a dust Collector and required enclosure(s).

Emission Units: EU IDs DU: 51a and 51b (Fly Ash and Bottom Ash Dust Collectors)

Pollutant of Concern: $PM_{2.5}$	
BACT Measure	**Monitoring, Recordkeeping and Reporting Requirements** [1]
0.02 gr/dscf Dust Collectors and enclosed ash handling systems	• Monitor that the fly ash and bottom ash dust collection systems are operating at all times fly and bottom ash is conveyed to truck loading locations. • Monitor that manufacturer's operating and maintenance procedures for the dust collectors are followed. Maintain records of maintenance conducted, and report summaries of such maintenance in each Facility Operating Report. • Submit an initial compliance certification indicating that ash handling and conveying systems are enclosed. • Monitor that door(s) and access panels to ash handling and conveying systems are closed while in operation. • Keep records identifying each time that the EU is operated outside a required enclosure. • Report as a permit deviation whenever either the fly or bottom ash conveying systems are operated without a dust collection system or required enclosure(s). • Monitor that overhead door(s) at ash loading building are closed while loading the trucks. Monitor that ash truck bodies are free of ash before they leave the building, and that their loads are tarped before they leave the building area. Monitor the implementation of a fugitive dust control program that includes provisions to minimize fugitive dust from coal ash handling operations.

Emission Units: EU IDs DU: 52 (Emergency Coal Storage Pile and Operations)

Pollutant of Concern: $PM_{2.5}$	
BACT Measure	**Monitoring, Recordkeeping and Reporting Requirements** [1]
1.42 TPY Use chemical stabilizers on dirt roads, install wind fencing, cover haul vehicles, water roads and dirt piles and wind awareness	• Monitor that chemical stabilizers are used to control fugitive dust on dirt roads as deemed necessary. • Monitor that wind fencing is in place around coal piles, where appropriate. • Report whether these measures have been implemented during each Facility Operating Report.

Stationary Source: Fort Wainwright – Doyon Utilities (DU) and US Army (FWA)

Emission Units: EU IDs 1, 2, 3, 4, 5 and 6 (230 MMBtu/hr – Coal Boilers)

Pollutant of Concern: SO_2	
BACT Measure	**Monitoring, Recordkeeping and Reporting Requirements** [1]
0.02 lb/MMBtu (3-hr avg)	• Conduct an initial SO_2 source test and report results as required in the corresponding Operating Permit
Dry Sorbent Injection	• Install, operate, and maintain dry sorbent injection at all times the units are in operation. • Report in the Operating Permit if there are any periods the EUs operated without the dry sorbent injection system.
Good Combustion Practices	• Keep records of maintenance conducted on emission units to comply with this BACT measure. • Keep a copy of the manufacturer's and the operator's recommended maintenance procedures.
Limit combined coal combustion in EU IDs 1 through 6 to 336,000 tons per year.	• Measure and record the total weight of coal prior to combustion in the EUs. • Report the monthly and consecutive 12-month total coal consumption at the stationary source.

Emission Units: FWA: EU IDs 8 – 10 (19 MMBtu/hr) and 40 (2.6 MMBtu/hr) Diesel-Fired Boilers

Pollutant of Concern: SO_2	
BACT Measure	**Monitoring, Recordkeeping and Reporting Requirements** [1]
Combust Only Ultra Low Sulfur fuel at no more than 0.0015 percent sulfur by weight	• For each shipment of fuel, test the sulfur content or keep receipts that specify fuel grade, date and time, and quantity of fuel received. Keep records of the results of sulfur content tests and receipts for fuel shipments. • Include a statement in each semi-annual operating report, a summary of fuel test results and shipping receipts from the reporting period.
Combined operating limit of 600 hours per year for FWA EUs 8, 9, and 10 hours/yr	• Monitor combined hours of operation on a 12-month rolling total basis. • Include in each semi-annual operating report, a summary of the 12-month rolling totals for each month within the reporting period. The 12-month rolling total for each calendar month is the sum of the total operating hours for that calendar month and the total monthly operating hours for the previous 11 calendar months.
Good Combustion Practices	• Keep records of maintenance conducted on emission units to comply with this BACT measure. • Keep a copy of the manufacturer's and the operator's recommended maintenance procedures.

[1] While the substantive requirements are described here, for any permit containing the requirement, the actual language may differ in non-substantive ways and include additional details.

	• Comply with the boiler tune-up procedures and MR&R requirements in NESHAP Subpart DDDDD.

Emission Units: EU IDs DU: 8; FWA: 11, 12, 13, 50, 51, 53, and 54 (Large Diesel-Fired Engines, Fire Pumps, and Generators > 500 hp)

Pollutant of Concern: SO_2	
BACT Measure	**Monitoring, Recordkeeping and Reporting Requirements** [1]
Combust Only Ultra Low Sulfur fuel at no more than 0.0015 percent sulfur by weight	• For each shipment of fuel, test the sulfur content or keep receipts that specify fuel grade, date and time, and quantity of fuel received. Keep records of the results of sulfur content tests and receipts for fuel shipments. • Include a statement in each semi-annual operating report, a summary of fuel test results and shipping receipts from the reporting period.
Good Combustion Practices	• For DU EU ID 8 and FWA IDs 50 and 51, report compliance with maintenance requirements under 40 CFR 60 Subpart IIII. • For FWA EU IDs 11, 12, 13, 53, and 54 demonstrate compliance by complying with the Good Air Pollution Control Practice Condition 70 in Operating Permit AQ0236TVP04.

Emission Units: EU IDs DU: 8; FWA EU 11, 12, 13, 50, 51, 53, and 54 (Diesel-Fired Engines >500 hp)

Pollutant of Concern: SO_2	
BACT Measure	**Monitoring, Recordkeeping and Reporting Requirements** [1]
• Limit DU EU 8 to 500 hours/yr	• Demonstrate compliance by complying with Condition 2 of Minor Permit AQ1121MS02.
• Limit FWA EU 11, 12 and 13 combined hours to 600 hours/yr	• Demonstration compliance by complying with Conditions 5.3 of Minor Permit AQ0236MSS02.
• Limit non-emergency operation of FWA Eus 50, 51, 53, and 54 to 100 hours/yr each	• For FWA EU IDs 50 and 51, demonstrate compliance by complying with the NSPS Subpart IIII emergency engine requirements listed in 40 CFR 4211(f). • For FWA EU IDs 53 and 54, demonstrate compliance by monitoring the engine's operating hours and reporting in the operating report.

Emission Units: EU IDs DU: 9, 14, 22, 23, 29a, 30a, 31a, 32a, 33a, 34, 35a, 36, 37a; FWA EUs: 26 through 39, 52, and 55 through 69 (Small Diesel-Fired Engines, Fire Pumps, and Generators < 500 hp)

Pollutant of Concern: SO_2	
BACT Measure	**Monitoring, Recordkeeping and Reporting Requirements** [1]

Combust Only Ultra Low Sulfur fuel at no more than 0.0015 percent sulfur by weight	• For each shipment of fuel, test sulfur content or keep receipts that specify fuel grade, date and time, and quantity of fuel received. Keep records of the results of sulfur content tests and receipts for fuel shipments. • Include a statement in each semi-annual operating report, a summary of fuel test results or shipping receipts from the reporting period.
Limit of 100 hours per year each for non-emergency operation	• Monitor operation of non-emergency use to ensure a limit of 100 hours per year each per engine.
Good Combustion Practices	• Keep records of manufacturer's maintenance procedures. • Monitor maintenance schedules to determine whether manufacturer's recommendations are followed. • Certify following good combustion practices in each semi-annual operating report.

AQ0236TVP04 Emission Units 2023

The table below identifies the significant emission units at the stationary source as authorized under the Permit Nos. AQ0236TVP04 and AQ0236MSS03.

EU ID	EU Name	Description	Rating/Size	Install
8	Backup Diesel-Fired Boiler 1	Cleaver-Brooks Model No. D-4555 (located at Bassett Hospital)	19 MMBtu/hr	Est. 2003-2004
9	Backup Diesel-Fired Boiler 2	Cleaver-Brooks (located at Bassett Hospital)	19 MMBtu/hr	Est. 2003-2004
10	Backup Diesel-Fired Boiler 3	Cleaver-Brooks (located at Bassett Hospital)	19 MMBtu/hr	Est. 2003-2004
11	Backup Diesel-Electric Generator 1	Caterpillar Model No. 3512 (located at Bassett Hospital)	900 kW	2003
12	Backup Diesel-Electric Generator 2	Caterpillar Model No. 3512 (located at Bassett Hospital)	900 kW	2003
13	Backup Diesel-Electric Generator 3	Caterpillar Model No. 3512 (located at Bassett Hospital)	900 kW	2003
22	VOC Extraction and Combustion	Restoration activities	N/A	1993
23	Fort Wainwright Landfill	Landfill	1.97 million m^3/yr	1962
24	Aerospace Activities	Painting and Degreasing	Not applicable	1950's
26	Emergency Generator	Cummins QSB7-G5 NR3 Hangar	324 hp	2012
27	Emergency Generator	John Deere 402HF285B Building 1580	67 hp	2009
28	Emergency Generator	Caterpillar C9 Genset Building 3406	398 hp	2007
29	Emergency Generator	SDMO TM30UCM Building 3567	47 hp	2005
30	Fire Pump	John Deere 6081AF001 Building 2089	275 hp	2007
31	Fire Pump #1	Clarke DDFP-04AT Building 1572	235 hp	1994
32	Fire Pump #2	Clarke DDFP-04AT Building 1572	235 hp	1994
33	Fire Pump #3	Clarke DDFP-04AT Building 1572	235 hp	1994
34	Fire Pump #4	Clarke DDFP-04AT Building 1572	235 hp	1994
35	Fire Pump #1	Cummins N-885-F Building 2080	240 hp	1977
36	Fire Pump #2	Cummins N-885-F Building 2080	240 hp	1977
37	Fire Pump	Clarke JU4H-UF40 Building 3498	105 kW	2005
38	Fire Pump #1	Clarke PDFP-06YT Building 5009	120 hp	1996
39	Fire Pump #2	Clarke PDFP-06YT	120 hp	1996

US Army Garrison, Fort Wainwright
AQ0236TVP04 2023 FCE Emission Unit Inventory

EU ID	EU Name	Description	Rating/Size	Install
		Building 5009		
40	Boiler	Weil-McLain BL-988-SW Building 5007	2.6 MMBtu/hr	1985
50	Emergency Generator Engine	Building 1060	762 hp	2010
51	Emergency Generator Engine	Building 1060	762 hp	2010
52	Emergency Generator Engine	Building 1193	82 hp	2002
53	Emergency Generator Engine	Building 1555	587 hp	2008
54	Emergency Generator Engine	Building 2117	1,059 hp	2005
55	Emergency Generator Engine	Building 2117	212 hp	2005
56	Emergency Generator Engine	Building 2088	71 hp	2007
57	Emergency Generator Engine	Building 2296	212 hp	2005
58	Emergency Generator Engine	Building 3004	71hp	2007
59	Emergency Generator Engine	Building 3028	35 hp	1976
60a?	Emergency Generator Engine	Building 3407	230 hp	2023
61	Emergency Generator Engine	Building 3703	50 hp	1993
62	Emergency Generator Engine	Building 5108	18 hp	2011
63	Emergency Generator Engine	Building 1620	68 hp	2003
64	Emergency Generator Engine	Building 1054	274 hp	2010
65	Emergency Generator Engine	Building 4390	274 hp	2010
66	Emergency Generator Engine	Building 3007	235 hp	2014
67	Emergency Generator Engine	Building 2121	67 hp	2016
68?	Emergency Generator Engine	Building 3025	324 hp	2017
69?	Emergency Generator Engine	Building 3030	86 hp	2023
N/A	Paved Roads	Fugitive PM	8,376,750 vehicle miles traveled/year	Various
N/A	Unpaved Roads	Fugitive PM	23,506 vehicle miles traveled/year	Various

Commented [SPPCUIP(1]: Previous EU60 replaced in 2023 with 125kW/230hp emergency generator engine

Commented [SPPCUIP(2]: New EU

Commented [SPPCUIP(3]: New EU

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PO Box 74040
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November 13, 2023

James Plosay
Alaska Department of Environmental Conservation
PO Box 111800
Juneau AK 99811-1800

Re: Revised FWA CHPP SO_2 Reduction Analysis

At your request, Doyon Utilities, LLC ("DU") reached out to the contractor who provided an earlier BACT CHPP SO_2 Reduction Analysis; an updated analysis is enclosed. This completed analysis is the exclusive property of DU and may contain information that is confidential and proprietary to third parties, provided and providable only under restricted disclosure.

We are supplying this information solely as a courtesy, at your request, and for the specific limited purpose of aiding you in resolving the Serious SIP. Based on your need for expediency, DU has not delayed forwarding the information to redact or otherwise painstakingly identify Confidential Business Information (CBI) or Controlled Defense Information (CDI). All information provided with this correspondence should be treated as confidential and proprietary. DU does not waive any rights of confidentiality, limited disclosure, or ownership of proprietary information.

Please take all necessary steps to ensure restricted disclosure of this material. If you are unwilling or unable to restrict disclosure, please return or destroy the substantive content enclosed without copying or further dissemination.

If you have comments or questions on this submittal please respond to Kathleen Hook khook@doyonutilities.com by November 27, 2023.

Sincerely,

Shayne Coiley
Senior Vice President
Doyon Utilities, LLC

cc: L. Florence, President, DU
K. Hook, Director of Environment, DU
T. Howard, Director of Engineering, DU
J. Meyer, Chief Operations & Maintenance, FWA Garrison
F, Sangren, COR, FWA Garrison
J. Olds, ADEC
M. Coss, ADEC
D. Jones. ADEC
N. Czarnecki, ADEC

CHPP SO_2 REDUCTION ANALYSIS

Addendum A

BLACK & VEATCH PROJECT NO. 406418
BLACK & VEATCH FILE NO. 40.1001

PREPARED FOR

Doyon Utilities

7 NOVEMBER 2023

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Introduction

Black & Veatch developed a report titled "CHPP SO_2 Reduction Analysis" in 2021 for Doyon Utilities, LLC (DU). The report was for DU's central heat and power plant (CHPP) that serves the United States Army base at Fort Wainwright (FWA), Alaska, which is located within the Fairbanks North Star Borough (FNSB). The report was in response to the EPA's review of the Alaska Department of Environmental Conservation's (ADEC) Serious State Implementation Plan (SIP), which warranted a more thorough analysis of the cost estimations of SO_2 control technologies. Using the five-step approach prescribed for Best Available Control Technology (BACT) analyses, the report identified DSI to be the most cost-effective control technology.

Upon review of the report, the EPA provided several comments to DU, which were dispositioned, and on August 24, 2022 in a memorandum from Zach Hedgpeth of the EPA to Matthew Jentgen, also of the EPA, it was determined that, "ADEC either needs to adopt and implement the best performing control technology as SO_2 BACT or revise its SIP to include technologic or economic infeasibility demonstrations with this analysis."

Comments from industry have been provided to the EPA's determination. One of the comments is regarding the removal efficiency used in the Black & Veatch report for Dry Sorbent Injection (DSI). The report used an emission rate of 0.12 lb/MMBtu for the DSI system, which resulted in a removal efficiency of 79.4 percent. Subsequently companies involved with DSI systems have provided information demonstrating DSI systems are capable of achieving removal rates upwards of 90 percent, even up to 95 percent. Since the EPA has stated that ADEC needs to implement the best performing SO_2 control technology, this addendum to the 2021 report is provided showing that DSI systems can achieve the same removal efficiencies that were assumed for the wet flue gas desulfurization (WFGD) systems, spray dry absorber (SDA), and circulating dry scrubbers (CDS).

Removal Efficiency

The 2021 report used costs and information from two equipment suppliers and one sorbent supplier. The equipment suppliers were BACT Process Systems, LLC and United Conveyor, LLC (UCC). The sodium bicarbonate (SBC) supplier was Solvay. All three companies were contacted in support of this update, and all three have provided information in support of increasing the removal rate for DSI systems.

BACT Process Systems, LLC

BACT Process Systems was not able to provide detailed documentation in support of this addendum due to other business obligations, but in a phone conversation, they noted that the DSI system at Eielson Air Force Base, which they provided, has been achieving removal rates in the low 90 percentages. Indeed, in a draft document published by ADEC titled "Technical Analysis of State Controllable Sources," it's noted that Eielson is achieving removal rates of 91 percent for the year 2019.[1] This is of note, because Eielson Air Force Base is also located in the FNSB and burns the same type of coal as the CHPP. BACT Process Systems believes that a DSI system at the CHPP should be capable of achieving similar removal efficiencies, at minimum.

[1] Alaska Department of Environmental Conversation. *III.K.13.F. Technical Analysis of State Controllable Sources*, 2022, Table III.K.13.F-29, Page 37

United Conveyor, LLC

UCC provided detailed information in support of this addendum. In UCC's experience, removal efficiencies up to 95 percent are achievable. Some of the specifics of information shared by UCC is considered confidential, and it was therefore not disclosed to Black & Veatch. However, the following two figures were shared, both from coal-fired power plants (PRB is for Powder River Basin coal, which has some similarities to the coal burned at the CHPP, and NSR is for normalized stoichiometric ratio, which is the amount of sorbent injected per amount of SO_2 removed).

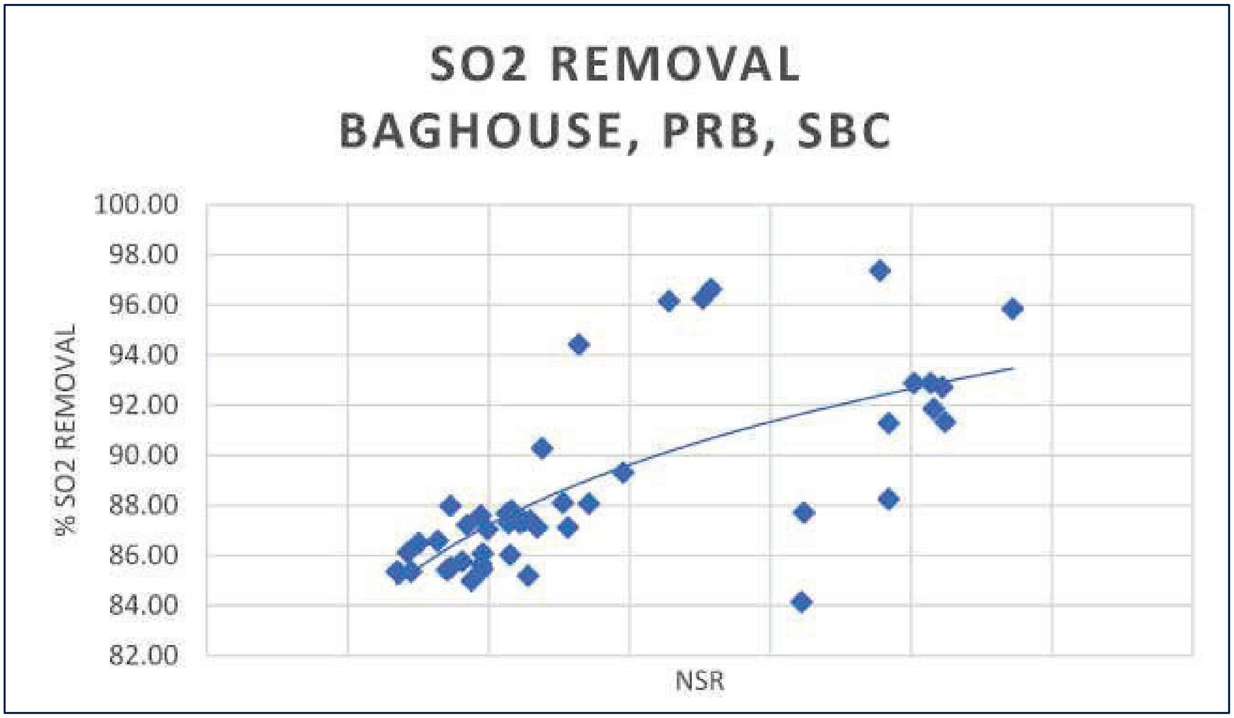

Figure 1 **SO_2 Removal Efficiency vs NSR for Coal-Fired Plant 1 (UCC)**

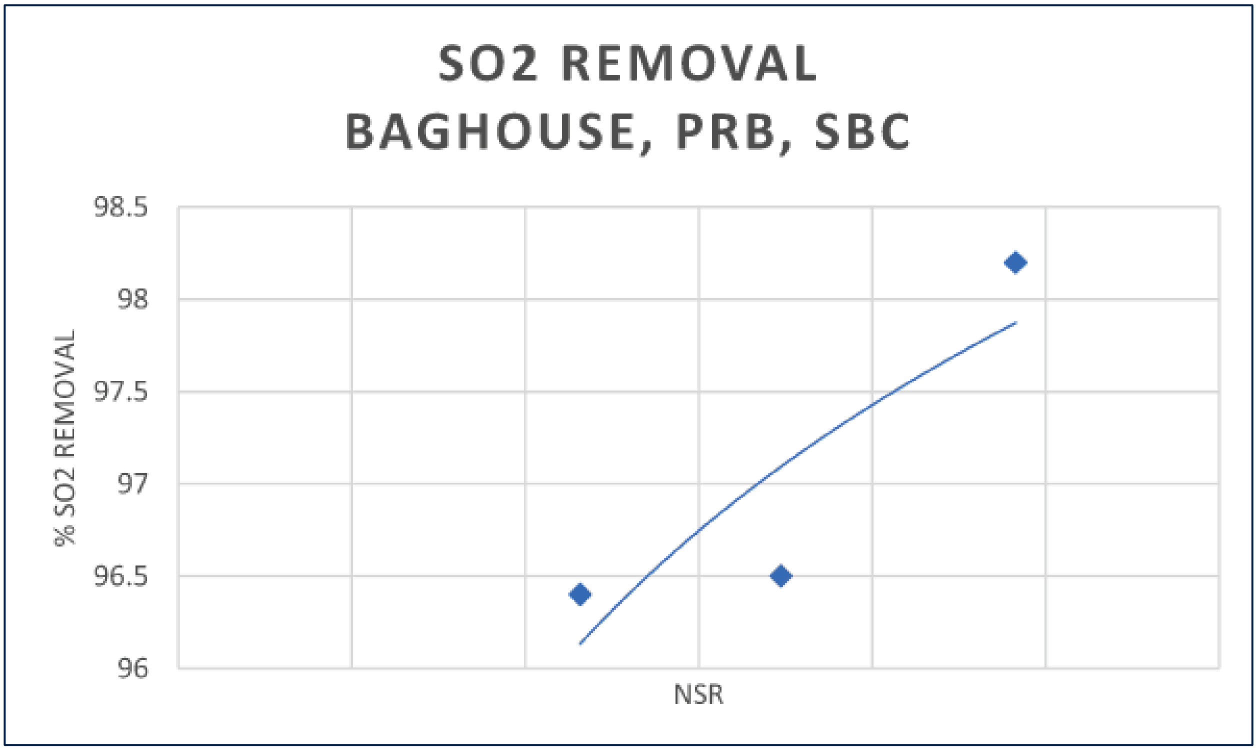

Figure 2 **SO_2 Removal Efficiency vs NSR for Coal-Fired Plant 2 (UCC)**

As can be seen from Figures 1 and 2, there is strong evidence that using sodium bicarbonate as sorbent in DSI applications can achieve well over 90 percent removal efficiency. UCC will not be able to confirm they would provide a performance guarantee over 90 percent for DU's CHPP without more detailed analysis, such as CFD modeling, but UCC has provided a guarantee of 93 percent removal efficiency in the past. This is the highest guarantee that UCC has provided to date, but this rate was what was required by their client. UCC believes that higher performance guarantees could be provided, pending detailed analysis of the facility and flue gas properties.

Some factors that solidify a 93 percent removal efficiency or higher include residence time and dispersion. Sorbent particles will have greater chances to interact with SO_2 molecules with increased residence time. During the 2021 DSI evaluation, the proposed injection locations for DSI was towards the bottom of the vertical drop that the boilers' exhaust ducts take before turning horizontal to enter the pulse jet fabric filters (PJFF). These locations were selected due to the installation considerations for new structural steel and platforms for accessing the injection lances. If the platforms were installed at the top of the vertical drop, more steel would be required and the installation would be more expensive, but this would increase the residence time. UCC recommends increasing the residence time, so this addendum incorporates this recommendation.

The dispersion of the sorbent is important, because the sorbent has to be well dispersed throughout the duct in order to interact with as many SO_2 molecules as possible. UCC believes that their proprietary injection lances will provide sufficient dispersion, and the relatively small duct diameters will further help improve the dispersion. Therefore, no changes to the sorbent dispersion were recommended or incorporated as part of this addendum.

Black & Veatch also asked UCC about the relatively low temperatures of the CHPP's flue gas and its effect on removal efficiency. The bulk, average temperature of the flue gas is 277 °F, while most coal-fired power plants have temperatures greater than 300 °F. UCC does not believe that this average temperature should be a cause for concern, because "at 277 °F, our (UCC) data shows that there is little effect on SO_2 removal performance relative to higher temperatures."

Solvay

Solvay provided additional information for this study. In their experience, 99 percent SO_2 removal was achieved at a coal-fired plant in France with an injection temperature of 250-300 °F. Solvay also has provided sorbent to a coal-fired power plant in the northwest USA that is achieving over 90 percent SO_2 removal with injection temperature around 300 °F. Solvay has several additional references that use their product and have achieved removal rates well above 90 percent, but their temperatures are above the CHPPs. Additionally, the flue gas characteristics are different due to not being coal-fired power plants. For example, two sludge incinerator facilities are achieving near 99 percent removal, and a cement facility is likewise achieving 99 percent removal. Still, based on their experience, Solvay is confident that DSI systems using their SBC can achieve removal rates well above the 80 percent used in the 2021 report. In their opinion, which was shared by UCC, removal rates are not set as much by the DSI system and sorbent, but rather, they are dependent on what the client needs to achieve. Solvay's experience list of system that have achieved removal efficiency levels is included in the appendix.

Solvay's position on removal rates is not impacted by the low temperatures at the CHPP. When questioned about the topic of injection temperatures, Solvay stated that SBC is "activated" over a wide range of temperatures, which in their experience is 250-1500 °F. Therefore, while some of the case studies that Solvay shared operate at higher temperatures, they still show evidence that higher removal rates can be readily achieved.

NSR values were also shared by Solvay, and they are lower than what UCC has experienced. While the values may be different, the NSR values seen by both companies confirm that UCC's NSR values are reasonable to use.

Cost Estimate Updates

The cost effectiveness of DSI systems is updated in this addendum based on a 93 percent removal efficiency. This removal efficiency is based on the performance of Eielson's DSI system, UCC's past performance guarantee on a coal-fired power plant, UCC's shared data for two coal-fired power plants, and Solvay's shared case studies. Higher removal efficiencies may be achieved upon installation and operation, but for the purposes of this study, 93 percent is the highest, defendable removal efficiency that can be used. In order to achieve a 93 percent removal efficiency, the injection rate of SBC must significantly increase. In the 2021 study, 425 lb/h was used for the SBC flowrate, but for this addendum, [redacted] will be required per boiler at full load. This translates to a total flowrate of [redacted] for all 6 units. The flowrate of SBC affects the annual costs for sorbent consumption and byproduct disposal, which are updated.

Since both Solvay and UCC recommended increasing the residence time as much as possible, the platforms in the 2021 study have been moved from the bottom of the ducts' vertical run to the top. This means additional structural steel is needed, and installation costs are greater due to construction at higher elevations. An additional $200,000 has been added to the DSI costs to account for this change. Installing the platforms at the top of the vertical run also means that the boiler building will be used as a structural support; however, based on the building's age, asbestos is expected in the building materials. Using cost values from RSMeans for the city of Fairbanks, an indicative cost of $100,000 is carried in this addendum's cost estimate for asbestos remediation. A contractor specializing in asbestos remediation was not consulted as part of this effort.

Other edits made to the cost estimates as part of this addendum, as well as the assumptions used, include the following:

- In order to evaluate all control technologies on the same basis, the direct costs, which includes the purchased equipment costs (PEC), for all of the technologies evaluated in 2021 have been updated for inflation by using the Chemical Engineering Plant Cost Index (CEPCI), which is referenced in the EPA's Cost Control Manual.
  - No other changes have been made to the other control technologies' evaluation aside from the adjustment due to inflation.
  - Specific values used for CEPCI were 946.5 for September 2021 and 1013.1 for June 2023 (June was selected for being the most recent non-preliminary data).
- Indirect costs were estimated in the 2021 report by using factored estimates based on the total direct costs. These factors were based on past project information. The factors were not reevaluated as part of this effort, but the values are updated due to the update in direct costs (inflation for all technologies, and updated removal efficiency for DSI).
- No changes have been made to any of the assumptions used elsewhere in the report, such as removal efficiencies of other technologies, storage capacity requirements of sorbents, maximum operating conditions, turndown ratios, cost rates for sorbents, electricity consumption, water usage, byproduct disposal, and number of operators.
- The most significant change made to the direct annual costs were changes to the DSI system's costs for sorbent consumption and byproduct disposal. The costs associated with power consumption should be relatively the same, because the main power consumer (the mills used to reduce the sorbent particle sizes) was not changed. The mills used in the 2021 study were capable of processing a wide range of flowrates, and according to UCC, their capacity was sufficient to handle the significant increase in injection rate.
- The rate of labor and electricity cost were updated in this addendum based on direction from DU. The cost for other variable annual costs have not significantly changed since the 2021 report.
- Indirect costs were calculated as a function of other costs, so they have likewise been updated. For example, the 2021 used 2 percent of the total capital investment (TCI) to calculate the administrative charges as prescribed by the EPA's Control Cost Manual. This percentage was maintained, but since the TCI increased, so did the administrative charges.
- Doyon Utilities maintains that the AFUDC is an amount that they will need to pay, but since the EPA has commented that this should not be applied, this amount is removed from the cost estimates.

- The capital recovery factor (CRF) was determined using the EPA Control Cost Manual's equation (equation 1.30 in the latest update to Section 5, SO_2 and Acid Gas Controls). In the original report, an interest rate of 7.5 percent was used, but per the latest rate as of October 2023, 8.5 percent is used in this addendum.

The updated values for the control technologies' cost estimates are shown in the tables below, and full summary sheets can be found in the appendix.

Table 1 Capital Cost Summary for Control Technologies, 2023 US Dollars

CATEGORY	WFGD – CAUSTIC	WFGD - LIMESTONE	SDA	CDS	DSI
Total Direct Costs	[redacted]				
Purchased Equipment					
Foundation & Supports					
Structural Steel					
Handling & Erection					
Electrical					
Piping					
Insulation					
Painting					
Instr. & Controls					
Site Preparation					
Buildings					
New Wet Stack					
Total Indirect Costs					
Engineering					
Construction & Field					
Start-up					
Performance Test					
Contingencies					
Total Capital Cost	$110,262,000	$126,374,000	$166,101,000	$196,447,000	$28,424,000

Table 2 Annual Cost Estimate Summary for Control Technologies

CATEGORY	WFGD - CAUSTIC	WFGD - LIMESTONE	SDA	CDS	DSI
Total Direct Costs	$6,367,000	$5,188,000	$4,034,000	$4,887,000	$5,869,000
Op. / Support Labor	$918,000	$1,224,000	$918,000	$1,071,000	$153,000
Maintenance Labor	$1,010,000	$1,346,000	$1,010,000	$1,178,000	$168,000
Maintenance Materials	$1,010,000	$1,346,000	$1,010,000	$1,178,000	$168,000
Reagent	[redacted]				
Byproduct Disposal					
Aux. and ID Fan Power					
Water					
Total Indirect Costs	$12,465,000	$14,286,000	$18,778,000	$22,209,000	$2,621,000
Administrative Charges	$2,205,000	$2,527,000	$3,322,000	$3,929,000	$563,000
Cost for Capital Recovery	$10,260,000	$11,759,000	$15,456,000	$18,280,000	$3,184,000
Total Annual Cost (TAC)	**$18,832,000**	**$19,474,000**	**$22,812,000**	**$27,096,000**	**$9,082,000**

Cost Effectiveness

Based on the cost estimates and new removal efficiency of the DSI system, the evaluation of the systems' cost effectiveness has been updated. Table 3 and Figure 3 show the updated cost effectiveness values and the incremental cost effectiveness.

Table 3 Impact Analysis and Cost Effectiveness

ALL FEASIBLE TECHNOLOGIES	UNIT	WFGD - CAUSTIC	WFGD - LIMESTONE	SDA	CDS + PJFF	DSI
Emission Performance Level	lb/MMBtu	0.04	0.04	0.07	0.07	0.04
PTE SO_2 Emissions	tons/yr	100.9	100.9	176.6	176.6	100.9
SO_2 Emission Removed	tons/yr	1369.07	1369.07	1293.36	1293.36	1369.07
Capital Costs	1,000$	$110,262	$126,374	$166,101	$196,447	$28,424
Total Annualized Cost	1,000$	$18,832	$19,474	$22,812	$27,096	$9,082
Cost Effectiveness	$/ton SO_2	$13,755	$14,224	$17,638	$20,950	$6,636
Incremental Cost Effectiveness	$/ton SO_2	Infinite	Infinite	-$44,113	Infinite	N/A
*Note: Only WFGD-Caustic and DSI are on the least-cost envelope; incremental analysis is shown for reference only						

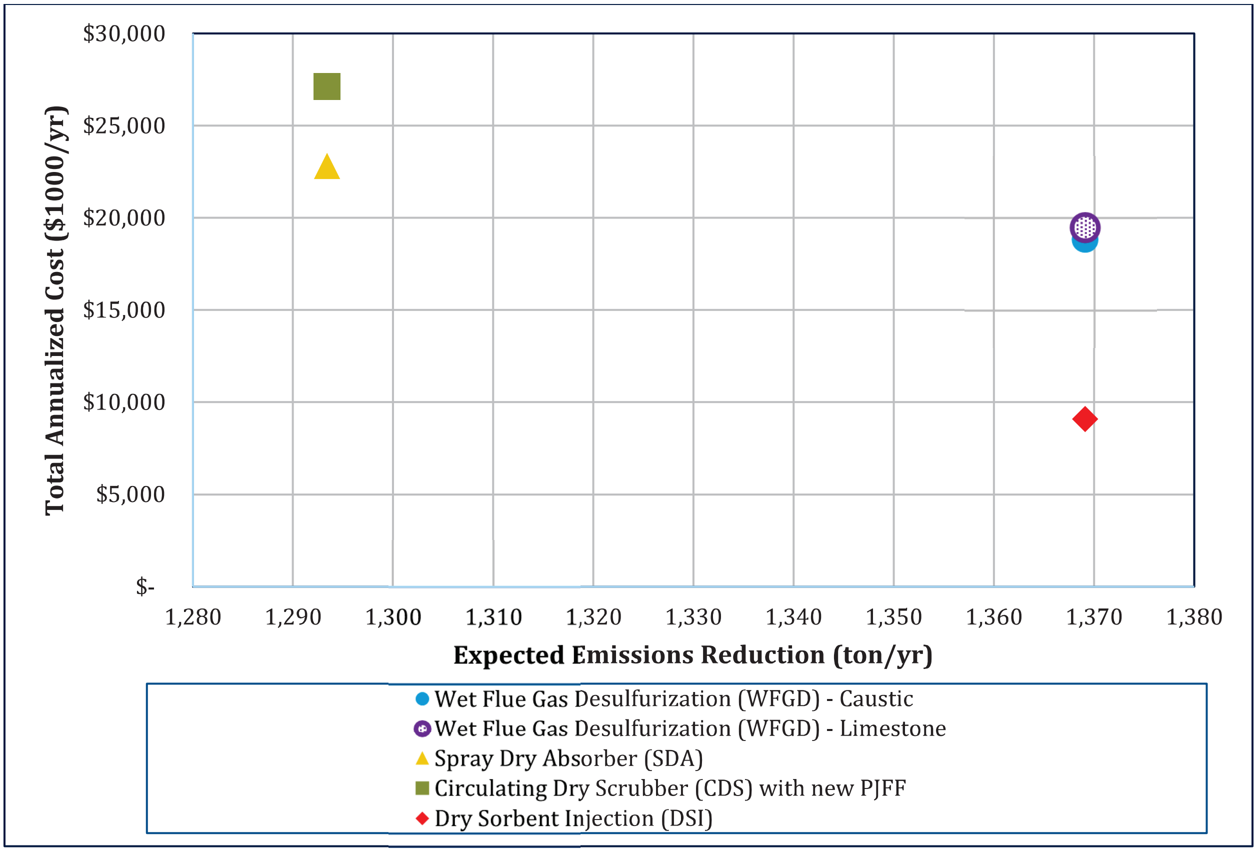

Figure 3 **Total Annualized Cost vs SO_2 ton/yr Removed**

As Table 3 shows, the DSI system is the most cost-effective technology and can be capable of achieving the same levels of SO_2 reduction as the other control technologies. Typically, there is a clear positive correlation between cost and emissions reduction, and a "least-cost envelope" can be drawn on the graph. For this evaluation, the envelope cannot be drawn, because the DSI system can achieve the same reduction as other technologies. The DSI stands alone as the least cost option relative to the other technologies evaluated in the 2021 study, and again as part of this addendum.

The assumptions and design basis for determining the cost effectiveness are the same from the original study, aside from the cost updates for the DSI as described herein. Some of primary design considerations from the original study are listed below.

- The coal (from the Usibelli mine) is assumed to have a 0.25 percent sulfur content to account for maximum design conditions. The sulfur content results in an emission rate of 0.58 lb/MMBtu of SO_2 at full load.
- Each unit is assumed to be operating at full load, with the air quality control systems designed for all six units operating at full load.
- 28 days of storage capacity is needed for the DSI system.
- The PJFF is assumed to be capable of handling the additional solids loading from the DSI system.
- A heated enclosure is assumed to be needed for maintenance during the winter months.

Appendix A – Solvay Experience List

SOLVAiR

SOLVAY

EXPERIENCE

- **Sludge incineration**. Strict emission values require both a high SOx and HCl mitigation. See the attached reference list for refineries. All of them can be visited.
  - >99% SOx mitigations at 210°C in the French incinerator of La Seyne-sur- Mer, France: 3000–5000mg/Nm_3 with peaks up to 9000mg/Nm_3 down to 50mg/Nm_3. Flow rate 23.000 Nm_3/h at stack
  - >99% SOx mitigations at 180-190°C in the Polish incinerator of Gdansk: average values 2800mg/Nm_3 down to 50mg/Nm_3. Flow rate 13.000 Nm_3/h at stack.

- **Glass production**. Examples of SOx mitigation from 750 mg/Nm_3 to below 5mg/Nm_3 at 345°C using an electrostatic precipitator. Flow rates per float glass line up are typically 90.000Nm_3/h.

- **Sintering plants:** the Meros off-gas cleaning systems supplied by Primetals Technologies uses sodium bicarbonate to all 3 lines at Kardemir (TUR) and Linz (AUT) plant. Each Meros plant is able to treat 400,000 Nm³/h of sinter off-gas, reducing SOx by more than 90% as well as delivering extremely low dust emissions.
  - https://www.primetals.com/fileadmin/user_upload/press-releases/2019/20190409/PR2019041756en.pdf
  - The plant in Linz, can treat up to 650,000 Nm3/h of flue gas.

Coal Power plants and **industrial boilers**. Depending on local regulations, mitigation rate up to 99%. Multiple injection to ensure a high dispersion of sorbent is normally required.

- **Torrelavega coal boilers (Spain).** Two boilers with 138MWth and 88MWth for pulverised coal (rusian steam coal <0,8% sulfur). Up to 90% SOx mitigation with flue gas flows of 170.000 and 110.000 Nm3/h (6%O_2, dry).
- **Coal power station in Illinois (USA).** Generators Westinghouse – load Max 571Net MW. Air emission controls with Electrostatic Precipitators, Overfired air, Selective Catalytic Reduction, Activated Carbon Injection, Dry Sorbent Injection (sodium bicarbonate). Estimated flowrate of 1.500.000Nm_3/h.

- **Cement production**. Combining waste gas by-pass and DSI to achieve 99% mitigation.
  - Salonit Anhovo plant in Slovenia can be visited.

Wax production. Very high SOx values in the raw gases, which can go up to 20.000 mg/Nm3 with a requirement of 300mg/Nm_3 at stack. Double filtration or residues recirculation is needed in this case. Flow rate: 5.500Nm_3/h.

- Industrial plant for the **recovery for Co, Ni, Mo from used catalyzers**.
  - >99% SOx mitigations at 210°C: 1500–5000mg/Nm_3 down to 50mg/Nm_3. Flow rate: 35.000Nm_3/h.

- Recent experiences in desulfuration of **diesel engine in boats**. Required mitigation around 98% when using 0.5% sulfur fuel. Quench with water required before entering the bag house filter (<230°C).

Appendix B – Cost Estimate Summary Sheets

Doyon Utilities Boilers 1-6 SO_2 Control Study

Technology: Wet Flue Gas Desulfurization (WFGD) - Caustic **Date:** 10/13/2023

Cost Item	2021 $	2023 $	Remarks			
CAPITAL COST	September 2021 CEPCI, Equipment Costs 946.5	June 2023 CEPCI, Equipment Costs 1013.1				
Direct Costs						
Purchased equipment costs	[redacted]		Vendor Quotes (Andritz and Tri-Mer)			
Absorber towers			Included with vendor quote			
Reagent feed system: receiving, storage			Included with vendor quote			
Make up water pump, dampers			Included with vendor quote			
Chemical feed pump (NaOH) and recycle pump			Included with vendor quote			
Mist eliminators and exhaust blowers			Included with vendor quote			
Flue gas handling: interconnecting ductwork			Included with vendor quote			
ID fans, Motors, VFDs			Vendor Quotes (Andritz)			
Subtotal capital cost (CC)						
Taxes						
Freight						
Total purchased equipment cost (PEC)						
Direct installation costs						
Foundation & supports			Engineering Estimator			
Structural steel			Engineering Estimator			
Handling & erection			Engineering Estimator			
Electrical			Engineering Estimator			
Piping			Engineering Estimator			
Insulation			Engineering Estimator			
Painting			Engineering Estimator			
Instrumentation and controls			Engineering Estimator			
Total direct installation costs (DIC)						
Site preparation			Engineering Estimator			
Buildings			Engineering Estimator			
New wet common stack			Engineering Estimator			
Total direct costs (DC) = (PEC) + (DIC)						
Indirect Costs						
Engineering			Engineering Estimator			
Construction and field expenses			Engineering Estimator			
Owner's cost			Engineering Estimator			
Start-up			Engineering Estimator			
Performance test			Engineering Estimator			
Contingencies			Engineering Estimator			
Total indirect costs (IC)						
Allowance for Funds Used During Construction (AFDC)			[(DC)+(IC)] X	7.50%	1 year(s)	
Total Capital Investment (TCI) = (DC) + (IC)	**$103,014,000**	**$110,262,000**				
ANNUAL COST						
Direct Annual Costs			Cap. Factor	39.0%	based on steam production from '11-'20	
Fixed annual costs						
Operating and support labor, 2021	$822,000	-	6 FTE and	137,000 $/year		Estimated manpower level
Operating and support labor, 2023	-	$918,000	6 FTE and	153,000 $/year		Estimated manpower level
Maintenance labor	$904,000	$1,010,000	1.1 x	Operating Labor		Per EPA Cost Manual
Maintenance materials	$904,000	$1,010,000	1 x	Maintenance Labor		Per EPA Cost Manual
Total fixed annual costs	$2,630,000	$2,938,000				
Variable annual costs						
Reagent: 50% solution of NaOH	[redacted]					Vendor budgetary quote
Byproduct disposal (Wastewater)						Vendor waste rate and DU cost
Auxiliary and ID fan power, 2021						EIA.gov
Auxiliary and ID fan power, 2023						DU direction
Water						Vendor water rate and DU cost
Total variable annual costs	$3,634,000	$3,429,000				
Total direct annual costs (DAC)	$6,264,000	$6,367,000				
Indirect Annual Costs						
Administrative charges (G&A, property tax, and insur.)	$2,060,000	$2,205,000	(TCI) X	2%	Cost Manual, Section 5 SO_2 Controls, 1.3.4.2	
Cost for capital recovery, 2021	$8,722,000	-	(TCI) X	8.47%	2021: CRF at 7.5% interest & 30 year life	
Cost for capital recovery, 2023	-	$10,260,000	(TCI) X	9.31%	2023: CRF at 8.5% interest & 30 year life	
Total indirect annual costs (IDAC)	$10,782,000	$12,465,000				
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$17,046,000**	**$18,832,000**				
Cost Effectiveness	**$12,451**	**$13,755**	$/ton SO_2			

Doyon Utilities Boilers 1-6 SO_2 Control Study

Technology: Wet Flue Gas Desulfurization (WFGD) - Limestone **Date:** 10/13/2023

Cost Item	2021 $	2023 $	Remarks				
CAPITAL COST	September 2021 CEPCI, Equipment Costs	June 2023 CEPCI, Equipment Costs					
	946.5	1013.1					
Direct Costs							
Purchased equipment costs	[redacted]		Vendor Quotes (Andritz and Tri-Mer)				
Absorber towers (tray, spray headers, mist eliminators)			Included with vendor quote				
Reagent feed system: receiving, storage			Included with vendor quote				
Absorber recirculation pumps and recirculating piping			Included with vendor quote				
Oxidation air blowers and injection lances			Included with vendor quote				
Reagent preparation system: silo, mills, pumps, and tanks			Included with vendor quote				
Dewatering system: hydrocyclone, vacuum filter, pumps, etc.							
Integral stack and pressure control inlet dampers							
Flue gas handling: interconnecting ductwork			Included with vendor quote				
Fan modifications: six booster fans			Vendor Quotes (Andritz)				
Subtotal capital cost (CC)							
Taxes							
Freight							
Total purchased equipment cost (PEC)							
Direct installation costs							
Foundation & supports			Engineering Estimator				
Structural steel			Engineering Estimator				
Handling & erection			Engineering Estimator				
Electrical			Engineering Estimator				
Piping			Engineering Estimator				
Insulation			Engineering Estimator				
Painting			Engineering Estimator				
Instrumentation and controls			Engineering Estimator				
Total direct installation costs (DIC)							
Site preparation			Engineering Estimator				
Buildings			Engineering Estimator				
New wet common stack			Engineering Estimator				
Total direct costs (DC) = (PEC) + (DIC)							
Indirect Costs							
Engineering			Engineering Estimator				
Construction and field expenses			Engineering Estimator				
Owner's cost			Engineering Estimator				
Start-up			Engineering Estimator				
Performance test			Engineering Estimator				
Contingencies			Engineering Estimator				
Total indirect costs (IC)							
Allowance for Funds Used During Construction (AFDC)			[(DC)+(IC)] X	7.50%		1 year(s)	
Total Capital Investment (TCI) = (DC) + (IC)	**$118,066,000**	**$126,374,000**					
ANNUAL COST							
Direct Annual Costs			Cap. Factor	39.0%	based on steam production from '11-'20		
Fixed annual costs							
Operating and support labor, 2021	$1,096,000	-		8 FTE and		137,000 $/year	Estimated manpower level
Operating and support labor, 2023	-	$1,224,000		8 FTE and		153,000 $/year	Estimated manpower level
Maintenance labor	$1,206,000	$1,346,000		1.1 x	Operating Labor		Per EPA Cost Manual
Maintenance materials	$1,206,000	$1,346,000		1 x	Maintenance Labor		Per EPA Cost Manual
Total fixed annual costs	$3,508,000	$3,916,000					
Variable annual costs							
Reagent: Limestone (CaCO3)	[redacted]						Mass balance calculations
Byproduct disposal (Landfill)							Mass balance calculations
Byproduct disposal (Wastewater)							Mass balance calculations
Auxiliary and ID fan power, 2021							EIA.gov
Auxiliary and ID fan power, 2023							DU direction
Water							Mass balance calc. and DU cost
Total variable annual costs	$1,477,000	$1,272,000					
Total direct annual costs (DAC)	$4,985,000	$5,188,000					
Indirect Annual Costs							
Administrative charges (G&A, property tax, and insur.)	$2,361,000	$2,527,000	(TCI) X	2%	Cost Manual, Section 5 SO_2 Controls, 1.3.4.2		
Cost for capital recovery, 2021	$9,997,000	-	(TCI) X	8.47%	2021: CRF at 7.5% interest & 30 year life		
Cost for capital recovery, 2023	-	$11,759,000	(TCI) X	9.31%	2023: CRF at 8.5% interest & 30 year life		
Total indirect annual costs (IDAC)	$12,358,000	$14,286,000					
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$17,343,000**	**$19,474,000**					
Cost Effectiveness	**$12,668**	**$14,224**	$/ton SO_2				

Doyon Utilities Boilers 1-6 SO2 Control Study

Technology: Spray Dry Absorber (SDA) **Date:** 10/13/2023

Cost Item	2021 $	2023 $	Remarks			
CAPITAL COST	September 2021 CEPCI, Equipment Costs 946.5	June 2023 CEPCI, Equipment Costs 1013.1				
Direct Costs						
Purchased equipment costs	[redacted]		Vendor Quotes (Andritz and B&W)			
Absorber vessels, including roof gas dispersers			Included with vendor quote			
Atomizers			Included with vendor quote			
Reagent preparation system: silo, slakers, pumps, and tanks			Included with vendor quote			
Recycle system: silo, rotary feeders, pumps, and tanks			Included with vendor quote			
Interconnecting ductwork and new PJFF inlet manifolds			Included with vendor quote			
ID fans, Motors, VFDs			Included with vendor quote			
Subtotal capital cost (CC)						
Taxes						
Freight						
Total purchased equipment cost (PEC)						
Direct installation costs						
Foundation & supports			Engineering Estimator			
Structural steel			Engineering Estimator			
Handling & erection			Engineering Estimator			
Electrical			Engineering Estimator			
Piping			Engineering Estimator			
Insulation			Engineering Estimator			
Painting			Engineering Estimator			
Instrumentation and controls			Engineering Estimator			
Total direct installation costs (DIC)						
Site preparation			Engineering Estimator			
Buildings			Engineering Estimator			
Total direct costs (DC) = (PEC) + (DIC)						
Indirect Costs						
Engineering			Engineering Estimator			
Construction and field expenses			Engineering Estimator			
Owner's cost			Engineering Estimator			
Start-up			Engineering Estimator			
Performance test			Engineering Estimator			
Contingencies			Engineering Estimator			
Total indirect costs (IC)						
Allowance for Funds Used During Construction (AFDC)			[(DC)+(IC)] X	7.5%	1 year(s)	
SDA Capital Investment (TCI) = (DC) + (IC)	**$155,181,000**	**$166,101,000**				
ANNUAL COST						
Direct Annual Costs			Cap. Factor	39.0%	based on steam production from '11-'20	
Fixed annual costs						
Operating labor, 2021	$822,000	-		6 FTE and	137,000 $/year	Estimated manpower level
Operating labor, 2023	-	$918,000		6 FTE and	153,000 $/year	Estimated manpower level
Maintenance labor	$904,000	$1,010,000		1.1 x	Operating Labor	Per EPA Cost Manual
Maintenance materials	$904,000	$1,010,000		1 x	Maintenance Labor	Per EPA Cost Manual
Total fixed annual costs	$2,630,000	$2,938,000				
Variable annual costs						
Reagent: Pebble Lime (CaO)	[redacted]					Vendor budgetary quote
Byproduct disposal (Landfill)						Vendor budgetary quote
Auxiliary and ID fan power, 2021						EIA.gov
Auxiliary and ID fan power, 2023						DU direction
Water						Mass balance calc. and DU cost
Total variable annual costs	$1,217,000	$1,096,000				
Total direct annual costs (DAC)	$3,847,000	$4,034,000				
Indirect Annual Costs						
Administrative charges (G&A, property tax, and insur.)	$3,104,000	$3,322,000	(TCI) X	2%	Cost Manual, Section 5 SO_2 Controls, 1.3.4.2	
Cost for capital recovery, 2021	$13,139,000	-	(TCI) X	8.47%	2021: CRF at 7.5% interest & 30 year life	
Cost for capital recovery, 2023	-	$15,456,000	(TCI) X	9.31%	2023: CRF at 8.5% interest & 30 year life	
Total indirect annual costs (IDAC)	$16,243,000	$18,778,000				
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$20,090,000**	**$22,812,000**				
Cost Effectiveness	**$15,533**	**$17,638**	\$/ton SO_2			

Technology: Circulating Dry Scrubber (CDS) **Date:** 10/13/2023

Cost Item	2021 $	2023 $	Remarks			
	September 2021 CEPCI, Equipment Costs	June 2023 CEPCI, Equipment Costs				
CAPITAL COST						
Direct Costs	946.5	1013.1				
Purchased equipment costs	[redacted]		Vendor Quotes (Andritz, B&W, and Tri-Mer)			
CDS vessels			Included with vendor quote			
Flue gas recirculation system			Included with vendor quote			
Humidification water system			Included with vendor quote			
Common fluidizing air system			Included with vendor quote			
Reagent prep systems: silo, rotary feeders, and convey air systems			Included with vendor quote			
Byproduct recirculation system: fluidization slides, rotary feeders, etc.			Included with vendor quote			
Common byproduct storage system, silo, rotary feeder, pug mill, etc.			Included with vendor quote			
Interconnecting ductwork			Included with vendor quote			
Six new PJFF systems, including casing			Included with vendor quote			
Compartment inlet/outlet dampers			Included with vendor quote			
Bags and cages			Included with vendor quote			
Pulse air headers and control system			Included with vendor quote			
New stacks			Included with vendor quote			
ID fans, Motors, VFDs			Included with vendor quote			
Subtotal capital cost (CC)						
Taxes						
Freight						
Total purchased equipment cost (PEC)						
Direct installation costs						
Foundation & supports			Engineering Estimator			
Structural steel			Engineering Estimator			
Handling & erection			Engineering Estimator			
Electrical			Engineering Estimator			
Piping			Engineering Estimator			
Insulation			Engineering Estimator			
Painting			Engineering Estimator			
Instrumentation and controls			Engineering Estimator			
Total direct installation costs (DIC)						
Site preparation			Engineering Estimator			
Buildings			Engineering Estimator			
Total direct costs (DC) = (PEC) + (DIC)						
Indirect Costs						
Engineering			Engineering Estimator			
Construction and field expenses			Engineering Estimator			
Owner's cost			Engineering Estimator			
Start-up			Engineering Estimator			
Performance test			Engineering Estimator			
Contingencies			Engineering Estimator			
Total indirect costs (IC)						
Allowance for Funds Used During Construction (AFDC)			[(DC)+(IC)] X	7.5%	for	1 year(s)
Total Capital Investment (TCI) = (DC) + (IC)	**$183,535,000**	**$196,447,000**				
ANNUAL COST						
Direct Annual Costs			Cap. Factor	39.0%	based on steam production from '11-'20	
Fixed annual costs						
Operating labor, 2021	$822,000	-	6 FTE and	137,000 $/year		Estimated manpower level
Operating labor, 2023	-	$1,071,000	7 FTE and	153,000 $/year		Estimated manpower level
Maintenance labor	$904,000	$1,178,000	1.1 x	Operating Labor		Per EPA Cost Manual
Maintenance materials	$904,000	$1,178,000	1 x	Maintenance Labor		Per EPA Cost Manual
Total fixed annual costs	$2,630,000	$3,427,000				
Variable annual costs						
Reagent: Hydrated Lime	[redacted]					Vendor budgetary quote
Byproduct disposal (Landfill)						Vendor budgetary quote
Water						Mass balance calc. and DU cost
Auxiliary and ID fan power, 2021						EIA.gov
Auxiliary and ID fan power, 2023						DU direction
Total variable annual costs						
Total direct annual costs (DAC)	$4,277,000	$4,887,000				
Indirect Annual Costs						
Administrative charges (G&A, property tax, and insur.)	$3,671,000	$3,929,000	(TCI) X	2%	Cost Manual, Section 5 SO_2 Controls, 1.3.4.2	
Cost for capital recovery, 2021	$15,540,000	-	(TCI) X	8.47%	2021: CRF at 7.5% interest & 30 year life	
Cost for capital recovery, 2023	-	$18,280,000	(TCI) X	9.31%	2023: CRF at 8.5% interest & 30 year life	
Total indirect annual costs (IDAC)	$19,211,000	$22,209,000				
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$23,488,000**	**$27,096,000**				
Cost Effectiveness	**$18,160**	**$20,950**	$/ton SO_2			

Doyon Utilities FWA CHPP

Technology: Dry Sorbent Injection (DSI) **Date:** 10/13/2023

Cost Item	2021 $	2023 $	Remarks/Cost Basis			
CAPITAL COST	September 2021 CEPCI, Equipment Costs 946.5	June 2023 CEPCI, Equipment Costs 1013.1				
Direct Costs (DC)						
Purchased equipment costs						
DSI system (blowers, silos, mills, lances)	[redacted]		Engineering estimate			
Piping			Engineering estimate			
Structural Steel			Engineering estimate			
Electrical equipment			Engineering estimate			
Misc. equipment			Engineering estimate			
Subtotal capital cost (CC)						
Taxes						
Freight						
Total purchased equipment cost (PEC)						
Direct installation costs						
Foundations			Engineering estimate			
Structural Steel			Engineering estimate			
Piping			Engineering estimate			
Electrical and Controls			Engineering estimate			
Total direct installation costs (DIC)						
Sitework			Engineering estimate			
Buildings			Engineering estimate			
Total direct costs (DC) = (PEC) + (DIC)						
Indirect Costs						
Engineering			Engineering Estimator			
Start-up			Engineering Estimator			
Owner's Cost			Engineering Estimator			
Contingencies			Engineering Estimator			
Total indirect costs (IC)						
Allowance for Funds Used During Construction (AFDC)			[(DC)+(IC)] X 7.5%	for	1 year(s)	
Total Capital Investment (TCI) = (DC) + (IC)	**$24,585,000**	**$28,424,000**				
ANNUAL COST						
Direct Annual Costs			Cap. Factor	39.0%	based on steam production from '11-'20	
Fixed annual costs						
Operating labor, 2021	$137,000	-	1 FTE and	137,000 $/year		Estimated manpower level
Operating labor, 2023	-	$153,000	1 FTE and	153,000 $/year		Estimated manpower level
Maintenance labor	$151,000	$168,000	1.1 x	Operating Labor		Per EPA Cost Manual
Maintenance materials	$151,000	$168,000	1 x	Maintenance labor		Per EPA Cost Manual
Total fixed annual costs	$439,000	$489,000				
Variable annual costs						
Reagent, 2021	[redacted]					Solvay budgetary quote
Reagent, 2023						Solvay budgetary quote
Water						DU direction
Sewer cost						DU direction
Auxiliary power, 2021						EIA.gov
Auxiliary power, 2023						DU direction
Solids disposal, 2021						Differential cost for offsite disposal
Solids disposal, 2023						Differential cost for offsite disposal
Total variable annual costs	$2,780,000	$5,380,000				
Total direct annual costs (DAC)	$3,219,000	$5,869,000				
Indirect Annual Costs						
Adminstrative charges	$492,000	$568,000	2% of TCI, per Cost Manual Table			
Cost for capital recovery, 30 year lifetime, 2021	$2,082,000	-	(TCI) X	8.47%	2021: CRF at 7.5% interest & 30 year life	
Cost for capital recovery, 30 year lifetime, 2023	-	$2,645,000	(TCI) X	15.47%	CRF at 5% interest & 8 year life	
Total indirect annual costs (IDAC), 30 year life	$2,574,000	$3,213,000				
Total Annual Cost (TAC) = (DAC) + (IDAC), 10 year life	**$5,793,000**	**$9,082,000**				
Cost Effectiveness	**$4,233**	**$6,636**	$/ton SO2			

From: Sartz, Patrik P CIV USARMY IMCOM PACIFIC (USA)
To: Jones, Dave F (DEC)
Cc: Petersen, Ida R CIV USARMY IMCOM PACIFIC (USA)
Subject: RE: USAG Alaska (Fort Wainwright) New Emergency Generator Specs (Email 2 of 2)
Date: Tuesday, April 2, 2024 4:36:25 PM
Attachments: April2024_FWA_EGSpecs - 2of2.zip

Email 2 of 2.

V/r,
Patrik

From: Sartz, Patrik P CIV USARMY IMCOM PACIFIC (USA)
Sent: Tuesday, April 2, 2024 4:32 PM
To: Jones, Dave F (DEC) <dave.jones2@alaska.gov>
Cc: Petersen, Ida R CIV USARMY IMCOM PACIFIC (USA) <ida.r.petersen.civ@army.mil>
Subject: USAG Alaska (Fort Wainwright) New Emergency Generator Specs (Email 1 of 2)

Mr. Jones,

Files are too large, so sending two separate emails. I'll also send the complete package via the Army's SharePoint site (DoDSafe).

I should have taken better notes during our conversation, but please see below for the information I remember you asking for:

AQ0236TVP04 EU ID	Army/FWA EU ID	Engine Applicable Tier	Supporting documentation (attached)
EU60a?	FWA-3407-IC-01	Tier 3	"2. EU60a_FWA-3407-IC-01_B3407OPCSubmittal.pdf"
EU66	FWA-3007-IC-01	Tier 3	"3. EU66_FWA-3007-IC-01_Photos.pdf" "4. EU66_FWA-3007-IC-01_nonroad-compression-ignition-2011-present.xlsx"
EU67	FWA-2121-IC-01	Tier 3	"5. EU67_FWA-2121-IC-01_InfoPhotos.pdf" "6. EU67_FWA-2121-IC-01_nonroad-compression-ignition-2011-present.xlsx"
EU68?	FWA-3025-IC-01	Tier 3	"7. EU68_FWA-3025-IC-01_OPC#3025.pdf"
EU69?	FWA-3030-IC-01	Tier 3	"8. EU69_FWA-3030-IC-01_B3030OPCSubmittal.pdf"

Also attached is the EU inventory I submitted as part of the 2023 FCE records request ("1. AQ0236TVP04 2023 FCE EU Inventory 10.16.2023 Rev").

I believe the number of insignificant distillate/fuel-fired boilers from the various BACT analyses and determinations include both boilers/hydronic heaters and warm air furnaces. If so, the current number is four significant (AQ0236TVP04 EU IDs 8, 9, 10 & 40) and number of insignificant is 55. Please see attached spreadsheet, tab named (“9. AQ0236TVP04_Projected Actual and Potential Emissions_USAGFWA_2024_FINAL.xlsx”)

Please let me know if you need any additional information.

Thank you!
V/r,
Patrik

Patrik Sartz
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