Fort Wainwright US Army Garrison and Doyon Utilities BACT Appendix

2015-04-24 ADEC Voluntary BACT Analysis for Fort Wainwright (Privatized Emission Units) letter to Eric Dick.pdf
2015-04-24 ADEC Voluntary BACT Analysis for Fort Wainwright (Privatized Emission Units) letter to Kathleen Hook.pdf
2015-10 DU FWA BACT Protocol V2.pdf
2015-12-11 DU BACT Protocol Cover letter V2.pdf
2016-02-03 DU_BACT_protocol_response.pdf
2017-01 S&L SCR Cost Development Methodology.pdf
2017-06 Final BACT_BACM Analyses Tech Memo_NEW.pdf
2017-06-05 Fort Wainwright DSI Amerair Industries LLC Proposal.pdf
2017-06-27 Page 1-2 Markup.pdf
2017-06-27 Page 9-1 Markup.pdf
2017-07-10 Cover Letter.pdf
2017-10-20 ADEC BACT Comment Letter Fort Wainwright.pdf
2017-10-20 ADEC Request for Additional Information for Fort Wainwright BACT Analysis.pdf
2018-05-23 DU Preliminary BACT Comments_Final.pdf
2018-05-23 EPA Comments on ADEC Preliminary Draft SIP Dev.pdf
2018-09-13 ADEC BACT Comment Letter Fort Wainwright 09.13.18.pdf
2018-09-13 ADEC Request for Additional Information for Fort Wainwright BACT Analysis 091018.pdf
2019-05-10 Fort Wainwright Attachments OCR.pdf
2019-05-10 Public Notice Fort Wainwright BACT Determination.pdf
2019-07-26 Col. Christopher Ruga e-mail Serious SIP Comments from Fort Wainwright (UNCLASSIFIED).pdf
2019-07-26 Doyon Utilities Serious SIP BACT Analysis Comments [CO 19-067].pdf
2019-07-26 Isaac Jackson e-mail Doyon Utilities Serious SIP BACT Analysis Comments.pdf
2019-07-26 Mark Ingoglia e-mail USAF SIP Comments.pdf
2019-10-04 DU FWA Additional BACT Comments.pdf
2019-11-13 Final Fort Wainwright BACT Determination.pdf
2019-11-13 Fort Wainwright Response to Comments.pdf
Fairbanks PM-2.5 Serious SIP - Information Requ....pdf
RE_ [EXTERNAL] _Fairbanks PM-2.5 Serious SIP - ....pdf

The following documents are included in the BACT but not listed in this appendix due to their electronic nature:

2016 scr_cost_manual_spreadsheet_vf Ft Wainwright (Army).xlsm
2016 sncr_cost_manual_spreadsheet_vf Ft Wainwright (Army).xlsm
2017-06-07 Amerair Cost for 50 and 80 percent control sncr (Army).xlsx
2017-07-21 Calculations for Emissions for EPA Tech review (Army).xlsx
2018-02-09 Fort Wainwright Wet Scrubber Cost Analysis (Army).xlsx
2019-04-25 Fort Wainwright - SO2 Controls Economic Analyses (ADEC).xlsx
2019-11-13 Fort Wainwright - SO2 Controls Economic Analyses Final (ADEC).xlsx
2019-11-13 Fort Wainwright SCR Economic Analysis (ADEC).xlsm
2019-11-13 Fort Wainwright SNCR Economic Analysis (ADEC).xlsm

THE STATE of ALASKA
GOVERNOR BILL WALKER

Department of Environmental Conservation

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April 24, 2015

Eric Dick, Environmental Manager
U.S. Army Fort Wainwright
ATTN: IMFW-PWE (E. Dick)
1060 Gaffney Road, # 4500
Fort Wainwright, AK 99703-4500

Subject: Voluntary BACT Analysis for Fort Wainwright (Privatized Emission Units)

Dear Mr. Dick:

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

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

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

Background

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

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

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

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

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

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

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

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

• Serious Area SIP inventory development starts:	January, 2015
• BACT kick off meeting:	March 5, 2015
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• Serious Area SIP submitted by ADEC to EPA:	December, 2017

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

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

Sincerely,

Denise Koch, Director
Division of Air Quality

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

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April 24, 2015

Kathleen Hook
Environmental Program Manager
Doyon Utilities, LLC
PO Box 74040
Fairbanks, AK 99707

Subject: Voluntary BACT Analysis for Fort Wainwright (Privatized Emission Units)

Dear Ms. Hook:

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

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Sincerely,

Denise Koch, Director
Division of Air Quality

cc: Larry Hartig, ADEC/ Commissioner's Office
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Cindy Heil, ADEC/Air Quality
Deanna Huff, ADEC/ Air Quality
Eric Dick/U.S. Army (Fort Wainwright)

$PM_{2.5}$ Serious Nonattainment Area BACT Analysis Protocol for the Fort Wainwright (Privatized Emission Units) Stationary Source

December 2015

Prepared by:

CONTENTS

ACRONYMS

AAC	Alaska Administrative Code
ADEC	Alaska Department of Environmental Conservation
BACM	Best Available Control Measures
BACT	Best Available Control Technology
CAA	Clean Air Act
CFR	Code of Federal Regulations
DU	Doyon Utilities, LLC
EPA	U.S. Environmental Protection Agency
EU	Emission Unit
EUAC	Equivalent Uniform Annual Cost
FNSB	Fairbanks North Star Borough
FWA	United States Army Garrison Fort Wainwright
ID	Identification
LAER	Lowest Achievable Emission Rate
NH_3	Ammonia
NO_X	Total Nitrogen Oxides
NESHAP	National Emission Standards for Hazardous Air Pollutants
NSPS	New Source Performance Standards
NSR	New Source Review
$PM_{2.5}$	Particulate matter with a diameter less than or equal to 2.5 micrometers
PM_{10}	Particulate matter with a diameter less than or equal to 10 micrometers
PSD	Prevention of Significant Deterioration
PTE	Potential to Emit
RACT	Reasonably Available Control Technology
RBLC	RACT/BACT/LAER Clearinghouse
SIP	State Implementation Plan
SLR	SLR International Corporation
SO_2	Sulfur Dioxide
tpy	Tons per Year
VOC	Volatile Organic Compounds

INTRODUCTION

The U.S. Environmental Protection Agency (EPA) designated portions of the Fairbanks North Star Borough (FNSB), including the City of Fairbanks and the City of North Pole, as a moderate nonattainment area for fine particulate matter ($PM_{2.5}$, particulate matter with a diameter less than 2.5 micrometers in diameter) in 2009 [74 FR 58,688; 13 November 2009]. This designation is for the 24-hour averaging period. The Alaska Department of Environmental Conservation (ADEC) expects EPA to change this designation to serious in or about June 2016 based on the failure to attain compliance with the 24-hour average $PM_{2.5}$ National Ambient Air Quality Standard (NAAQS) through the measures implemented to bring the moderate nonattainment area into attainment.

On March 23, 2015, EPA proposed changes to 40 Code of Federal Regulations (CFR) 51, Subpart Z, Provisions for Implementation of $PM_{2.5}$ National Ambient Air Quality Standards. These proposed changes, once finalized, will include the attainment plan submittal requirements that ADEC must address in the plan to bring the FNSB Serious $PM_{2.5}$ nonattainment area into attainment. In proposing this rule, EPA presented and solicited comments about several plan alternatives. As a result, the requirements which may be promulgated in the revised 40 CFR 51 Subpart Z are difficult to anticipate at this time.

One element of the attainment plan that ADEC must prepare for EPA approval is likely to be determining Best Available Control Technology (BACT) for certain stationary sources located in the nonattainment area. The Fort Wainwright (Privatized Emission Units) stationary source, owned and operated by Doyon Utilities, LLC (DU), is likely to be a stationary source for which a BACT analysis is required. In a letter dated April 24, 2015, ADEC asked DU to voluntarily prepare a BACT analysis that ADEC could then incorporate into the attainment planning process. ADEC made this request because the agency “has neither the funding nor the in depth knowledge of your facility’s infrastructure to determine the most appropriate BACT for your facility.” DU is responding to this request by submitting this BACT analysis protocol to ADEC for review, comment, and approval.

1. BACT ANALYSIS APPROACH

The methodology that will be used for identifying BACT will be the five step "top-down" process set forth in the proposed *EPA New Source Review Rule Revisions* (1996) and is outlined in the following subsections.

1.1 IDENTIFY ALL CONTROL TECHNOLOGIES

The first step of the BACT analysis will be to survey alternative control techniques and identify all "available" control options. Available control options are those air pollution control technologies or techniques with a practical potential for application to the emissions units and pollutants under evaluation. The following guidelines are used to identify available control options:

> The technology should be "demonstrated in practice". The control technology should have been installed and operating at a minimum of 50 percent of capacity for six months, and the performance should have been verified with a test or operational data at 90 percent of operational capacity.
>
> Controls applied to similar source categories, gas streams, and innovative control technologies should be examined. Process controls, such as combustion modifications, that are currently available from a supplier should be reviewed.

1.2 ELIMINATE TECHNICALLY INFEASIBLE CONTROL OPTIONS

In step two, the technical feasibility of each available control option will be evaluated based on source-specific factors. The use of control options, which would clearly result in technical difficulties precluding their successful use, will be deemed technically infeasible.

1.3 RANK REMAINING CONTROL OPTIONS BY EFFECTIVENESS

In step three, the effectiveness of control alternatives will be determined for all options not eliminated in step two. Control options are then ranked "top-down" in order of overall control effectiveness for the pollutant under review. Control options which would result in emissions that exceed Federal New Source Performance Standards (NSPS) or National Emission Standards for Hazardous Air Pollutants (NESHAP) applicable to the source can be eliminated.

1.4 EVALUATE MOST EFFECTIVE CONTROL OPTIONS

In step four, the energy, environmental, and economic impacts of control options will be considered, beginning with the top-ranked control alternative. If the most effective control option is shown to be inappropriate due to adverse impacts, that option will be eliminated and the next most stringent alternative will be evaluated. If the most stringent technology is selected as BACT, continuing the analysis will not be necessary.

1.5 SELECT BACT

Finally, in step five, the most effective control option not eliminated in step four will be proposed as BACT for the pollutant and emission unit under review.

The basis for comparing the economic impacts of control scenarios will be cost effectiveness. This value is defined as the total net annualized cost of control, divided by the tons of pollutant removed per year, for each control technique. Annualized costs include the annualized capital cost plus the financial requirements to operate the control system on an annual basis, including operating and maintenance labor, replacement parts, overhead, raw materials, and utilities.

Capital costs include both the direct and indirect costs to install the equipment. Direct installation costs include costs for foundations, erection, electrical, piping, insulation, painting, site preparation, and buildings. Indirect installation costs include costs for engineering and supervision, construction expenses, startup costs and contingencies.

For the analysis, all costs are expressed as an annualized cost, and cost-effectiveness values are then calculated. This approach of amortizing the investment into equal end-of-year annual costs is termed the Equivalent Uniform Annual Cost (EUAC). This approach is the EPA recommended method for estimating control costs. Templates for cost estimation purposes can be found in Appendix B.

For the purposes of the $PM_{2.5}$ Serious nonattainment BACT analysis, if a particular control technology is eliminated based on economic factors, the assumption will be made that the control technology is also uneconomic for smaller emission units.

1.6 DOCUMENTATION

Supporting documentation for the nonattainment BACT analysis will be provided and will include data to support control effectiveness assertions, cost estimates, and justification for eliminating control options based environmental or economic determinations, if applicable.

2. STATIONARY SOURCE DESCRIPTION

This section provides a description of the DU FWA (Privatized Emission Units) stationary source based on information provided in Operating Permit No. AQ1121TVP02 Revision 1 and the Statement of Basis (SOB) associated with that permit. Section 2.1 provides a BACT applicability analysis. Section 2.2 provides a description of the FWA stationary source and a detailed emission unit inventory for the DU FWA (Privatized Emission Units) stationary source.

2.1 BACT APPLICABILITY ANALYSIS

A stationary source in a serious nonattainment area that has potential emissions of more than 70 tons per year (tpy) of direct $PM_{2.5}$ or any $PM_{2.5}$ precursor is a major stationary source for serious $PM_{2.5}$ nonattainment purposes. Major stationary sources are expected to be subject to a BACT review. Table 1 provides the potential emissions for $PM_{2.5}$, sulfur dioxide (SO_2), nitrogen oxides (NO_X), volatile organic compounds (VOC), and ammonia (NH_3) for the FWA stationary source. DU and the U.S. Army are authorized to operate EUs at the FWA stationary source under Air Quality Operating Permit Nos. AQ1121TVP02 Revision 1 and AQ0236TVP03 Revision 1, respectively. Table 1 provides the potential to emit for the DU FWA (Privatized Emission Units), the U.S. Army FWA, and the total FWA stationary source based on information in the Statements of Basis for Permit Nos. AQ1121TVP02 Revision 1 and AQ0236TVP03 Revision 1.

Based on the potential emissions provided in Table 1, the stationary source potential $PM_{2.5}$, NO_X, and SO_2 emissions exceed the 70 tpy major source threshold. BACT analyses will be prepared for direct $PM_{2.5}$ and for NO_X and SO_2 as $PM_{2.5}$ precursors. BACT analyses will not be prepared for VOC and NH_3 based on the low potential emission values for those two air pollutants.

Table 1. FWA Serious Nonattainment Area Major Source Applicability

Pollutant	Potential Emissions			Major Source? >70 tpy PTE
	Doyon Utilities, LLC	US Army	Total	
$PM_{2.5}$	124.3[1]	3.1[2]	127.4	Yes
SO_2	1,767.2[1]	30.1[2]	1,797.3	Yes
NO_X	1,532.9[1]	42.2[2]	1,575.1	Yes
VOC	12.3[1]	13.4[2]	25.7	No
NH_3	<1[3]	NA[5]	<1 (estimated)	No

[1] From Table D of AQ1121TVP02 Revision 1 SOB.
[2] From Table D of AQ0236TVP03 Revision 1 SOB.
[3] Estimated potential emissions based on 336,000 tpy coal combustion limit and 0.565 lb/1,000 ton emission factor from WebFIRE.
[4] Not applicable.

2.2 DU FWA (PRIVATIZED EMISSION UNITS) EMISSION UNIT INVENTORY

Table 2 provides an emission unit inventory for the DU FWA (Privatized Emission Units) stationary source. The DU FWA facility consists of a Central Heat and Power Plant (CHPP) which includes six coal-fired boilers and a coal preparation plant. Backup power generation is provided by multiple diesel-fired reciprocating internal combustion engine (RICE) generators. Emergency backup for lift station pumps for the wastewater collection system is provided by diesel-fired RICE and pumps at multiple locations throughout the FWA (Privatized Emission Units) stationary source. DU will prepare a BACT analysis for $PM_{2.5}$ for all emission units shown in Table 2. DU will not prepare NO_X or SO_2 BACT analyses for EU IDs 7a, 7b, 7c, 51a, 51b, and 52 because the units do not emit NO_X or SO_2.

In summary, DU will prepare $PM_{2.5}$, NO_X and SO_2 BACT analyses for the following emission units:

- EU IDs 1 through 6, coal-fired boilers,
- EU ID 8, black start generator engine, and
- EU IDs 9 through 32 and 34 through 36, emergency engines. (EU ID 33 was permanently removed from service as described in the off-permit change notification submitted on October 2, 2015.)

DU will also prepare a $PM_{2.5}$ BACT analysis for EU IDs 7a, 7b, 7c, 51a, 51b, and 52.

Table 2. Facility Emission Unit Inventory[1]

Emission Unit				Fuel Type/	Maximum	Existing
ID	Description	Make/Model	Location	Material	Capacity	Controls
Coal-Fired Boilers						
1	Coal-Fired Boiler 3	Wickes	CHPP[2]	Coal	230 MMBtu/hr	Full-stream baghouse
2	Coal-Fired Boiler 4	Wickes	CHPP	Coal	230 MMBtu/hr	Full-stream baghouse
3	Coal-Fired Boiler 5	Wickes	CHPP	Coal	230 MMBtu/hr	Full-stream baghouse
4	Coal-Fired Boiler 6	Wickes	CHPP	Coal	230 MMBtu/hr	Full-stream baghouse
5	Coal-Fired Boiler 7	Wickes	CHPP	Coal	230 MMBtu/hr	Full-stream baghouse
6	Coal-Fired Boiler 8	Wickes	CHPP	Coal	230 MMBtu/hr	Full-stream baghouse
Black Start Generator Engine						
8	Black Start Generator Engine	Caterpillar 3516C	CHPP	ULSD[3]	2,937 hp	None
Emergency Engines						
9	Emergency Generator Engine	Detroit 6V92	1032	Diesel	353 hp	None
10	Emergency Generator Engine	Caterpillar C15	1060	Diesel	762 hp	None
11	Emergency Generator Engine	Caterpillar C15	1060	Diesel	762 hp	None
12	Emergency Generator Engine	Cummins B3.3	1193	Diesel	82 hp	None
13	Emergency Generator Engine	Caterpillar 3406C TA	1555	Diesel	587 hp	None
14	Emergency Generator Engine	Cummins QSL-G2 NR3	1563	Diesel	320 hp	None
15	Emergency Generator Engine	Detroit R1237M36	2117	Diesel	1,059 hp	None
16	Emergency Generator Engine	John Deere 6068TF250	2117	Diesel	212 hp	None
17	Emergency Generator Engine	John Deere 6068TF250	2088	Diesel	176 hp	None
18	Emergency Generator Engine	John Deere 6068HF150	2296	Diesel	212 hp	None
19	Emergency Generator Engine	John Deere 4045TF270	3004	Diesel	71 hp	None
20	Emergency Generator Engine	John Deere 4239D	3028	Diesel	35 hp	None
21	Emergency Generator Engine	Perkins 2046/1800	3407	Diesel	95 hp	None
22	Emergency Generator Engine	Cummins	3565	Diesel	35 hp	None
23	Emergency Generator Engine	John Deere 6068HF150	3587	Diesel	155 hp	None
24	Emergency Generator Engine	Cummins L634D-I/10386E	3703	Diesel	50 hp	None
25	Emergency Generator Engine	Caterpillar C1.5	5108	Diesel	18 hp	None

[1] Source: Section 2, Table A of Operating Permit No. AQ1121TVP02 Revision 1.
[2] Central Heat and Power Plant.
[3] Ultra Low Sulfur Diesel.

Table 2. Facility Emission Unit Inventory (Continued)

Emission Unit				Fuel Type/	Maximum	Existing
ID	Description	Make/Model	Location	Material	Capacity	Controls
Emergency Engines (Continued)						
26	Emergency Generator Engine	Cummins 4B3.9-G2	1620	Diesel	68 hp	None
27	Emergency Generator Engine	Caterpillar C6.6	1054	Diesel	274 hp	None
28	Emergency Generator Engine	Caterpillar C6.6	3004	Diesel	274 hp	None
29a	Emergency Pump Engine	John Deere 4045TF290	3565	Diesel	74 hp	None
30	Emergency Pump Engine	Detroit Diesel 10245100	3403	Diesel	75 hp	None
31a	Emergency Pump Engine	John Deere 4045TF290	3724	Diesel	74 hp	None
32	Emergency Pump Engine	Perkins	4162	Diesel	75 hp	None
34	Emergency Pump Engine	Detroit Diesel 10447000	3405	Diesel	220 hp	None
35	Emergency Pump Engine	John Deere 4045DF120	4023	Diesel	55 hp	None
36	Emergency Pump Engine	Detroit Diesel 4031-C	3563	Diesel	220 hp	None
Coal Dust						
7a	DC-01 South Coal Handling Dust Collector	Airlanco 169-AST-8	CHPP[4]	Coal Dust	13,150 acfm	Air Filtration
7b	DC-02 South Underbunker Dust Collector	Airlanco 16-AST	CHPP	Coal Dust	884 acfm	Air Filtration
7c	NDC-1 North Coal Handling Dust Collector	Dustex C67-10-547	CHPP	Coal Dust	9,250 acfm	Air Filtration
Fly Ash Dust						
51a	DC-1 Fly Ash Dust Collector	United Conveyor 32242	CHPP	Fly Ash Dust	3,620 acfm	Air Filtration
51b	DC-2 Bottom Ash Dust Collector	United Conveyor 32242	CHPP	Ash Dust	3,620 acfm	Air Filtration
Coal Storage Pile						
52	Coal Storage Pile	NA[5]	CHPP	Coal Dust	9 million cubic feet	Management Practices

[4] Central Heat and Power Plant.
[5] Not applicable.

3. REFERENCES

ADEC, *Statement of Basis of the Terms and Conditions for Permit No. AQ0236TVP03 Revision 1, US Army Garrison Fort Wainwright – Fort Wainwright,* November 10, 2015.

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U.S. EPA, Clean Air Act, http://www.epw.senate.gov/envlaws/cleanair.pdf, Accessed on June 23, 2015.

U.S. EPA, Federal Register, Vol. 61, No. 142, *Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NSR); Proposed Rule,* 40 CFR Parts 51 and 52, July 23, 1996.

U.S. EPA, Federal Register, Vol. 74, No. 218, *Air Quality Designations for the 2006 24-Hour Fine Particle ($PM_{2.5}$) National Ambient Air Quality Standards*, *Final Rule*, 40 CFR Part 81, November 13, 2009.

US EPA, *EPA Air Pollution Cost Control Manual*, EPA-452/B-02-001, Office of Air Quality Planning and Standards, Research Triangle Park, N.C., January 2002.

U.S. EPA, *New Source Review Workshop Manual – Prevention of Significant Deterioration and Nonattainment Area Permitting (Draft),* Office of Air Quality Planning and Standards, Research Triangle Park, N.C., October 1990.

U.S. EPA, WebFIRE, Technology Transfer Network Clearinghouse for Inventories and Emission Factors, http://cfpub.epa.gov/webfire, Accessed on June 18, 2015.

APPENDIX A

ADEC REQUEST FOR VOLUNTARY BACT ANALYSIS OF THE DU FWA (PRIVATIZED EMISSION UNITS)

THE STATE of ALASKA
GOVERNOR BILL WALKER

Department of Environmental Conservation

DIVISION OF AIR QUALITY
Director's Office

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Juneau, Alaska 99811-1800
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CERTIFIED MAIL: 7014 0514 0001 9932 8941
Return Receipt Requested

April 24, 2015

Kathleen Hook
Environmental Program Manager
Doyon Utilities, LLC
PO Box 74040
Fairbanks, AK 99707

Subject: Voluntary BACT Analysis for Fort Wainwright (Privatized Emission Units)

Dear Ms. Hook:

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

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

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

<u>Background</u>

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

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

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

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

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

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

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

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

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

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

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

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

Sincerely,

Denise Koch, Director
Division of Air Quality

cc: Larry Hartig, ADEC/ Commissioner's Office
Alice Edwards, ADEC/ Commissioner's Office
John Kuterbach, ADEC/ Air Quality
Cindy Heil, ADEC/Air Quality
Deanna Huff, ADEC/ Air Quality
Eric Dick/U.S. Army (Fort Wainwright)

APPENDIX B

EXAMPLE ECONOMIC ANALYSIS TEMPLATES

Table B-1. Example Total Capital Investment Determination

Capital Costs		
DIRECT COSTS	**Cost Factors**	
(1) Purchased equipment and material costs		
(a) Basic equipment		=
(b) Instrumentation		=
(c) Freight		=
(d) Labor		=
(e) Startup Spares		=
(f) Vendor representatives fees		=
Purchased Equipment and Materials Cost (PEMC)		=
(2) Direct Installation Costs		
(a) Concrete		=
(b) Piling		=
(c) Structural steel		=
(d) Electrical		=
(e) Painting		=
(f) Insulation		=
(g) Abovegrade piping		=
(h) Functional Checkouts		=
Direct Installation Costs (DIC)		=
Total Direct Costs (TDC)	(PEMC) + (DIC)	=
INDIRECT COSTS		
(3) Engineering, Procurement & Construction Support Services		=
(4) Performance tests		=
Total Indirect Costs (TIC)		=
MANAGEMENT AND CONTINGENCY COSTS		
(5) UOC Costs		=
(6) Contingency		=
Total Management and Contingency Costs (TM&CC)		=
TOTAL CAPITAL INVESTMENT (TCI)	(TDC)+(TIC)+(TM&CC)	=

Table B-2. Example Cost Effectiveness Determination

Annualized Costs		
DIRECT ANNUAL COSTS	**Cost Factors**	
(1) Operating labor		=
(2) Supervisory labor		=
(3) Maintenance labor		=
(4) Maintenance materials		=
(5) Utilities		
Fuel:		=
Electricity:		=
Total Direct Annual Costs (TDAC)		=
INDIRECT ANNUAL COSTS		
(6) Overhead		=
(7) Administrative Charges		=
(8) Property tax		=
(9) Insurance		=
(10) Capital Recovery	(CRF*TCI)	=
Capital Recovery Factor (CRF) [7% ROR, 10-year life] is 0.1424		
Total Indirect Annual Costs (TIAC)		=
TOTAL ANNUALIZED COSTS (TAC)	**(TDAC) + (TIAC)**	=
Cost Effectiveness Summary		
TOTAL TONS AVOIDED PER YEAR		=
COST EFFECTIVENESS ($ PER TON AVOIDED)	**(TAC)/(TPY)**	=

DOYON UTILITIES LLC

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December 11, 2015

Denise Koch, Director
Division of Air Quality
Alaska Department of Environmental Conservation
P.O. Box 11800
Juneau, Alaska 99811-1800

SUBJECT: $PM_{2.5}$ Serious Nonattainment Area BACT Analysis
Fort Wainwright (Privatized Emission Units) Stationary Source

Dear Ms. Koch,

Doyon Utilities, LLC (DU) requests clarification regarding the Voluntary $PM_{2.5}$ Nonattainment Best Available Control Technology (BACT) Analysis requested by the Alaska Department of Environmental Conservation (ADEC) in a letter dated April 24, 2015.

1) Please confirm that 2013 will be the baseline year if the Fairbanks North Star Borough (FNSB) $PM_{2.5}$ Moderate Nonattainment Area is re-designated as a Serious Nonattainment Area.

2) DU is considering preparing a Best Available Control Technology (BACT) analysis per the ADEC request of April 24, 2015. A BACT protocol is enclosed for ADEC review to provide an opportunity for ADEC to identify potential differences in interpretation of the nonattainment BACT analysis process for $PM_{2.5}$. Please provide any comment about this protocol to DU within 30 days of receipt. Please note the following points that are addressed in the protocol.

   a) In the protocol, DU assumes that the 70 tpy nonattainment BACT applicability threshold should be applied to the combined potential emissions of both stationary source operators located at FWA. Calculations supporting this determination can be found in Table 1 of the protocol and indicate that, based on ADEC guidance to date, a nonattainment BACT analysis is required for $PM_{2.5}$, SO_2, and NO_X.

   b) Based on preliminary discussions with ADEC, DU has inferred that a nonattainment BACT analysis is required only for permitted emission units. Please confirm that this approach is proper.

   c) As indicated in the ADEC April 24, 2015 request letter, BACT determinations used for SIP development are ultimately reviewed and approved by the EPA. DU requests that ADEC seek EPA Region 10 approval of the enclosed $PM_{2.5}$ Nonattainment BACT Analysis Protocol.

Please contact Kathleen Hook at 907-455-1540 or at khook@doyonutilities.com with any questions.

Sincerely,

Shayne Coiley
Senior Vice President

Attachment: $PM_{2.5}$ Serious Nonattainment Area BACT Analysis Protocol for Fort Wainwright (Privatized Emission Units)

cc: M. Meeks, FWA Garrison (e copy)
M. Miles, FWA Garrison (e copy)
C. Siebel, FWA Garrison (e copy)
C. Kimball, SLR – Fairbanks (w/o attachment)

CO 15-104

THE STATE of ALASKA
GOVERNOR BILL WALKER

Department of Environmental Conservation

DIVISION OF AIR QUALITY
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February 3, 2016

Shayne Coiley, Senior Vice President
Doyon Utilities, LLC
714 Fourth Avenue, Suite 100
PO Box 74040
Fairbanks, Alaska 99707

Subject: Response to PM2.5 Serious Nonattainment BACT Analysis Protocol for the Fort Wainwright (Privatized Emission Units)

Dear Mr. Coiley:

Thank you for submitting your PM2.5 Serious Nonattainment BACT Analysis Protocol for the Fort Wainwright (Privatized Emission Units).

The clarifications you have requested are below:

1. ADEC plans to use 2013 as the baseline year for the Serious Area SIP. The EPA Region 10 is aware that ADEC has chosen this year. However, the year will not be final until EPA Region 10 formally approves the emission inventory and baseline year with the submittal of the Serious Area SIP. The baseline year could only be chosen from one of the last three years of the design value that caused the Fairbanks area to become a Serious Area (2013, 2014, or 2015).
2. ADEC has reviewed the protocol and has no comments. The EPA Region 10 has provided informal comments on the BACT protocol that was submitted, which are included below. As discussed during the Fort Wainwright monthly meeting call on December 23rd, 2015, this response letter took longer than the requested 30 days due to the holidays.
    a. The BACT analysis should be conducted for the permitted emission units and the following pollutants are above the 70 Potential To Emit (PTE) Tons Per Year (TPY) threshold according the AQ1121TVP02 permit: $PM_{2.5}$, SO_2 and NO_X.
    b. A Serious Area BACT analysis is only required for permitted emission units.
    c. EPA Region 10 reviewed the protocol and made comments, but they will not approve the BACT analysis until it has been officially submitted by ADEC. (See the excerpt from an email below.)

Clean Air

EPA Region 10 Response to the PM2.5 Serious Nonattainment BACT Analysis Protocol for the Fort Wainwright (Privatized Emission Units):

"EPA is providing informal comments to you on the BACT protocol provided by Fort Wainwright (Privatized Emission Units). At this time, we are not approving the protocol –we will formally review and approve the BACT analysis if/when it is submitted to us as part of the Serious Area Attainment Plan.

Below are some additional comments on the protocol document.

BACT Protocol

1. *Please clarify which emission units at the facility would not fall into the category of permitted emission units.*
2. *Section 1 – The BACT analysis will be evaluated with respect to EPA BACT guidance. The protocol needs to be consistent with that guidance - this protocol will not govern should any inconsistency be identified.*
3. *Section 1.5 – This section should clarify that all cost analyses will be conducted in accordance with the EPA Air Pollution Control Cost Manual.*
4. *Section 1.5 – The final sentence should be modified as follows "…if a particular control technology is eliminated based on economic factors, the assumption will be made that the control technology is also uneconomic for smaller emission units, provided that all other factors besides size are equivalent." This clarification is necessary because the reasoning only applies for emission units that are the same basic type of equipment, burn the same fuel, have similar retrofit challenges, etc.*
5. *Section 1.6 – Cost information must be emission unit specific. BACT cannot be determined using generic cost ranges.*
6. *Section 1.6 – Each BACT analysis must provide the basis for each input value and assumption used in the analysis and calculations. Electronic (pdf) copies of the actual documents forming the basis for each assumption should be provided. If the documents are publicly available on the internet, functional links to the information is acceptable.*
7. *Section 2 – The BACT analyses need to be conducted based on potential to emit (PTE), and EPA will verify the basis for the PTE values used for each emission unit and each pollutant. The BACT analysis should provide the basis and actual calculations used to derive each PTE value. It is acceptable to cite another document that forms the basis for the PTE, but these underlying documents must be included as attachments to the BACT analysis, and must themselves include sufficient detail in order to clearly illustrate the basis for the PTE values.*

Thank you again for submitting your BACT protocol for ADEC and EPA Region 10 review.
If you have any further questions in order to complete a timely BACT analysis, please contact Dea Huff, Ph.D. (deanna.huff@alaska.gov) or me.

Sincerely,

Denise Koch, Director
Division of Air Quality

cc: Cindy Heil, ADEC/Non-Point Mobile Sources
Deanna Huff, ADEC/Non-Point Mobile Sources
John Kuterbach, ADEC/Air Permits Program
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Commented [KD1]: I'll send you their e-mail address.

IPM Model – Updates to Cost and Performance for APC Technologies

SCR Cost Development Methodology

Final

January 2017

Project 13527-001

Eastern Research Group, Inc.

Prepared by

Sargent & Lundy LLC

55 East Monroe Street • Chicago, IL 60603 USA • 312-269-2000

LEGAL NOTICE

This analysis ("Deliverable") was prepared by Sargent & Lundy, L.L.C. ("S&L"), expressly for the sole use of Eastern Research Group, Inc. ("Client") in accordance with the agreement between S&L and Client. This Deliverable was prepared using the degree of skill and care ordinarily exercised by engineers practicing under similar circumstances. Client acknowledges: (1) S&L prepared this Deliverable subject to the particular scope limitations, budgetary and time constraints, and business objectives of the Client; (2) information and data provided by others may not have been independently verified by S&L; and (3) the information and data contained in this Deliverable are time sensitive and changes in the data, applicable codes, standards, and acceptable engineering practices may invalidate the findings of this Deliverable. Any use or reliance upon this Deliverable by third parties shall be at their sole risk.

This work was funded by the U.S. Environmental Protection Agency (EPA) through Eastern Research Group, Inc. (ERG) as a contractor and reviewed by ERG and EPA personnel.

SCR Cost Development Methodology

Purpose of Cost Algorithms for the IPM Model

The primary purpose of the cost algorithms is to provide generic order-of-magnitude costs for various air quality control technologies that can be applied to the electric power generating industry on a system-wide basis, not on an individual unit basis. Cost algorithms developed for the IPM model are based primarily on a statistical evaluation of cost data available from various industry publications as well as Sargent & Lundy's proprietary database and do not take into consideration site-specific cost issues. By necessity, the cost algorithms were designed to require minimal site-specific information and were based only on a limited number of inputs such as unit size, gross heat rate, baseline emissions, removal efficiency, fuel type, and a subjective retrofit factor.

The outputs from these equations represent the "average" costs associated with the "average" project scope for the subset of data utilized in preparing the equations. The IPM cost equations do not account for site-specific factors that can significantly impact costs, such as flue gas volume, temperature, and do not address regional labor productivity, local workforce characteristics, local unemployment and labor availability, project complexity, local climate, and working conditions. In addition, the indirect capital costs included in the IPM cost equations do not account for all project-related indirect costs a facility would incur to install a retrofit control such as project contingency.

Establishment of the Cost Basis

The 2004 to 2006 industry cost estimates for SCR units from the "Analysis of MOG and Ladco's FGD and SCR Capacity and Cost Assumptions in the Evaluation of Proposed EGU 1 and EGU 2 Emission Controls" prepared for Midwest Ozone Group (MOG) were used by Sargent & Lundy LLC (S&L) to develop the SCR cost model. In addition, S&L included data from "Current Capital Cost and Cost-effectiveness of Power Plant Emissions Control Technologies" prepared by J. E. Cichanowicz for the Utility Air Regulatory Group (UARG) in 2010, and 2013. The published data were significantly augmented by the S&L in-house database of recent SCR projects. The current industry trend is to retrofit high-dust hot-side SCRs. The cold-side tail-end SCRs encompass a small minority of units and as such were not considered in this evaluation.

The data was converted to 2016 dollars based on the Chemical Engineering Plant Index (CEPI) data. Additional proprietary S&L in-house data from 2012 to 2016 were included to confirm the index validity. Finally, the cost estimation tool was benchmarked against recent SCR projects to confirm the applicability to the current market conditions.

The available data was analyzed in detail regarding project specifics such as coal type, NO_x reduction efficiency, and air pre-heater requirements. The data was refined by fitting each data set with a least-squares curve to obtain an average $/kW project cost as a function of unit size. The data set was then collectively used to generate an average least-squares curve fit. Based on the recently acquired data, it appears the overall capital

SCR Cost Development Methodology

cost has increased by approximately 15% over the costs published in 2013. Analysis of the data indicates that these units had a high degree of retrofit difficulty, high elevation, or low quality fuel.

The costs for retrofitting a plant smaller than 100 MW increase rapidly due to the economy of size. S&L is not aware of any SCR installations in recent years for smaller than 100-MW units. In light of the recent retirement of smaller than 200-MW size units, the evaluation of SCR technology may not be necessary. The older units, which comprise a large proportion of the plants in this range, generally have more compact sites with very short flue gas ducts running from the boiler house to the chimney. Because of the limited space, the SCR reactor and new duct work can be expensive to design and install. Additionally, the plants might not have enough margins in the fans to overcome the pressure drop due to the duct work configuration and SCR reactor, and therefore new fans may be required.

A combined SCR for small units is not a feasible option. The flue gas from the boiler is treated after the economizer in the SCR before entering the air heater. Thus, SCR is an integral part of the heat recovery cycle of an individual boiler. Each boiler has to be retrofitted with its own SCR reactor. Minor savings can be achieved by utilizing a common reagent storage and preparation system.

The least-squares curve fit was based upon an average of the SCR retrofit projects in recent years. Retrofit difficulties associated with an SCR may result in significant capital cost increases. A typical SCR retrofit was based on:

- Retrofit Difficulty = 1 (Average retrofit difficulty);
- Gross Heat Rate = 9500 Btu/kWh;
- SO_2 Rate = < 3.0 lb/MMBtu;
- Type of Coal = Bituminous; and
- Project Execution = Multiple lump-sum contracts.

Methodology

Inputs

To predict SCR retrofit costs several input variables are required. The unit size in MW is the major variable for the capital cost estimation followed by the type of fuel (Bituminous, PRB, or Lignite), which will influence the flue gas quantities as a result of the different typical heating values. The fuel type also affects the air pre-heater costs if ammonium bisulfate or sulfuric acid deposition poses a problem. The unit heat rate factors into the amount of flue gas generated and ultimately the size of the SCR reactor and reagent preparation. A retrofit factor that equates to the difficulty of constructing the system must be defined. The NO_x rate and removal efficiency will impact the amount of catalyst required and size of the reagent handling equipment.

SCR Cost Development Methodology

The cost methodology is based on a unit located within 500 feet of sea level. The actual elevation of the site should be considered separately and factored into the cost due to the effects on the flue gas volume. The base SCR and balance of plant costs are directly impacted by the site elevation. These two base cost modules should be increased based on the ratio of the atmospheric pressure at sea level and that at the unit location. As an example, a unit located 1 mile above sea level would have an approximate atmospheric pressure of 12.2 psia. Therefore, the base SCR and balance of plant costs should be increased by:

14.7 psia/12.2 psia = 1.2 multiplier to the base SCR and balance of plant costs

The NO_x removal efficiency specifically affects the SCR catalyst, reagent and steam costs. The lower level of NO_x removal is recommended as:

- 0.07 NO_x lb/MMBtu – Bituminous;
- 0.05 NO_x lb/MMBtu – PRB; and
- 0.05 NO_x lb/MMBtu – Lignite.

Outputs

Total Project Costs (TPC)

First, the installed costs are calculated for each required base module. The base module installed costs include:

- All equipment;
- Installation;
- Buildings;
- Foundations;
- Electrical; and
- Average retrofit difficulty.

The base modules are:

BMR =	Base SCR cost
BMF =	Base reagent preparation cost
BMA =	Base air pre-heater cost
BMB =	Base balance of plant costs including: ID or booster fans, ductwork reinforcement, piping, etc…
BM =	BMR + BMF + BMA + BMB

SCR Cost Development Methodology

The total base module installed cost (BM) is then increased by:

- Engineering and construction management costs at 10% of the BM cost;
- Labor adjustment for 6 x 10-hour shift premium, per diem, etc., at 10% of the BM cost; and
- Contractor profit and fees at 10% of the BM cost.

A capital, engineering, and construction cost subtotal (CECC) is established as the sum of the BM and the additional engineering and construction fees.

Additional costs and financing expenditures for the project are computed based on the CECC. Financing and additional project costs include:

- Owner's home office costs (owner's engineering, management, and procurement) at 5% of the CECC; and
- Allowance for Funds Used During Construction (AFUDC) at 6% of the CECC and owner's costs. The AFUDC is based on a two-year engineering and construction cycle.

The total project cost is based on a multiple lump-sum contract approach. Should a turnkey engineering procurement construction (EPC) contract be executed, the total project cost could be 10 to 15% higher than what is currently estimated.

Escalation is not included in the estimate. The total project cost (TPC) is the sum of the CECC and the additional costs and financing expenditures.

Fixed O&M (FOM)

The fixed operating and maintenance (O&M) cost is a function of the additional operations staff (FOMO), maintenance labor and materials (FOMM), and administrative labor (FOMA) associated with the SCR installation. The FOM is the sum of the FOMO, FOMM, and FOMA.

The following factors and assumptions underlie calculations of the FOM:

- All of the FOM costs are tabulated on a per-kilowatt-year (kW-yr) basis.
- In general, half of an operator's time is required to monitor a retrofit SCR. The FOMO is based on that half-time requirement for the operations staff.
- The fixed maintenance materials and labor are a direct function of the process capital cost at 0.5% of the BM for units less than 300 MW and 0.3% of the BM for units greater than or equal to 300 MW.
- The administrative labor is a function of the FOMO and FOMM at 3% of the sum of (FOMO + 0.4 FOMM).

SCR Cost Development Methodology

Variable O&M (VOM)

Variable O&M is a function of:

- Reagent use and unit costs;
- Catalyst replacement and disposal costs;
- Additional power required and unit power cost; and
- Steam required and unit steam cost.

The following factors and assumptions underlie calculations of the VOM:

- All of the VOM costs are tabulated on a per-megawatt-hour (MWh) basis.
- The reagent consumption rate is a function of unit size, NO_x feed rate, and removal efficiency.
- The catalyst replacement and disposal costs are based on the NO_x removal and total volume of catalyst required.
- The additional power required includes increased fan power to account for the added pressure drop and the power required for the reagent supply system. These requirements are a function of gross unit size and actual gas flow rate.
- The additional power is reported as a percent of the total unit gross production. In addition, a cost associated with the additional power requirements can be included in the total variable costs.
- The steam usage is based upon reagent consumption rate.

Input options are provided for the user to adjust the variable O&M costs per unit. Average default values are included in the base estimate. The variable O&M costs per unit options are:

- Urea cost in $/ton. Due to escalation, urea cost was updated to reflect average 2016 pricing. The urea solution cost includes the cost of a 50% urea solution prepared at the manufacturing site with additives suitable for avoiding corrosion in the injectors and transportation cost. The solution cost is significantly higher than that of solid urea. If solid urea is purchased, it would require additional storage, solutionizing equipment, and additional deionized water processing capability at the plant site.
- Catalyst costs that include removal and disposal of existing catalyst and installation of new catalyst in $/cubic meter. No escalation has been observed for catalyst removal and disposal cost since 2013.
- Auxiliary power cost in $/kWh. No noticeable escalation has been observed for auxiliary power cost since 2013.
- Steam cost in $/1000 lb.
- Operating labor rate (including all benefits) in $/hr.

SCR Cost Development Methodology

The variables that contribute to the overall VOM are:

VOMR	=	Variable O&M costs for urea reagent
VOMW	=	Variable O&M costs for catalyst replacement & disposal
VOMP	=	Variable O&M costs for additional auxiliary power
VOMM	=	Variable O&M costs for steam

The total VOM is the sum of VOMR, VOMW, VOMP, and VOMM. Table 1 shows a complete capital and O&M cost estimate worksheet.

SCR Cost Development Methodology

Table 1. Example of a Complete Cost Estimate for an SCR System

Variable	Designation	Units	Value	Calculation
Unit Size	A	(MW)	500	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Heat Rate	C	(Btu/kWh)	9500	<--- User Input
NOx Rate	D	(lb/MMBtu)	0.3	<--- User Input
SO2 Rate	E	(lb/MMBtu)	3	<--- User Input
Type of Coal	F		Bituminous	<--- User Input
Coal Factor	G		1	Bit=1.0, PRB=1.05, Lig=1.07
Heat Rate Factor	H		0.95	C/10000
Heat Input	I	(Btu/hr)	4.75E+09	A*C*1000
NOx Removal Efficiency	K	(%)	75	<--- User Input
NOx Removal Factor	L		0.9375	K/80
NOx Removed	M	(lb/hr)	1069	D*I/10^6*K/100
Urea Rate (100%)	N	(lb/hr)	747	M*0.525*60/46*1.01/0.99
Steam Required	O	(lb/hr)	845	N*1.13
Aux Power **Include in VOM?** ☑	**P**	**(%)**	**0.55**	0.56*(G*H)^0.43
Urea Cost (50% wt solution)	R	($/ton)	350	<--- User Input
Catalyst Cost	S	($/m3)	8000	<--- User Input (Includes removal and disposal of existing catalyst and installation of new catalyst)
Aux Power Cost	T	($/kWh)	0.06	<--- User Input
Steam Cost	U	($/klb)	4	<--- User Input
Operating Labor Rate	V	($/hr)	60	<--- User Input (Labor cost including all benefits)

Costs are all based on 2016 dollars

Capital Cost Calculation		Example	Comments
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty.			
BMR ($) =	310000*(B)*(L)^0.2*(A*G*H)^0.92	$ 88,780,000	SCR (ductwork modifications and strengthening, reactor, bypass) island cost
BMF ($) =	564000*(M)^0.25	$ 3,225,000	Base reagent preparation cost
BMA ($) =	IF E ≥ 3 AND F=Bituminous, THEN 69000*(B)*(A*G*H)^0.78, ELSE 0	$ 8,446,000	Air heater modification / SO3 control (Bituminous only & > 3lb/MMBtu)
BMB ($) =	529000*(B)*(A*G*H)^0.42	$ 7,042,000	ID or booster fans & auxiliary power modification costs
BM ($) =	BMR + BMF + BMA + BMB	$ 107,493,000	Total bare module cost including retrofit factor
BM ($/KW) =		215	Base cost per kW
Total Project Cost			
A1 = 10% of BM		$ 10,749,000	Engineering and Construction Management costs
A2 = 10% of BM		$ 10,749,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc…
A3 = 10% of BM		$ 10,749,000	Contractor profit and fees
CECC ($) = BM+A1+A2+A3		**$ 139,740,000**	Capital, engineering and construction cost subtotal
CECC ($/kW) =		**279**	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC		$ 6,987,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1		$ 146,727,000	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =		**293**	Total project cost per kW without AFUDC
B2 = 6% of (CECC + B1)		$ 8,804,000	AFUDC (Based on a 2 year engineering and construction cycle)
TPC ($) = CECC + B1 + B2		**$ 155,531,000**	Total project cost
TPC ($/kW) =		**311**	Total project cost per kW

SCR Cost Development Methodology

Table 1 Continued

Variable	Designation	Units	Value	Calculation
Unit Size	A	(MW)	500	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Heat Rate	C	(Btu/kWh)	9500	<--- User Input
NOx Rate	D	(lb/MMBtu)	0.3	<--- User Input
SO2 Rate	E	(lb/MMBtu)	3	<--- User Input
Type of Coal	F		Bituminous	<--- User Input
Coal Factor	G		1	Bit=1.0, PRB=1.05, Lig=1.07
Heat Rate Factor	H		0.95	C/10000
Heat Input	I	(Btu/hr)	4.75E+09	A*C*1000
NOx Removal Efficiency	K	(%)	75	<--- User Input
NOx Removal Factor	L		0.9375	K/80
NOx Removed	M	(lb/hr)	1069	D*I/10^6*K/100
Urea Rate (100%)	N	(lb/hr)	747	M*0.525*60/46*1.01/0.99
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Aux Power Cost	T	($/kWh)	0.06	<--- User Input
Steam Cost	U	($/klb)	4	<--- User Input
Operating Labor Rate	V	($/hr)	60	<--- User Input (Labor cost including all benefits)

Costs are all based on 2016 dollars

Fixed O&M Cost

FOMO ($/kW yr) = (1/2 operator time assumed)*2080*V/(A*1000)	$	0.13	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = (IF A < 300 then 0.005*BM ELSE 0.003*BM)/(B*A*1000)	$	0.64	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	$	0.01	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**$**	**0.78**	Total Fixed O&M costs

Variable O&M Cost

VOMR ($/MWh) = N*R/(A*1000)	$	0.52	Variable O&M costs for Urea
VOMW ($/MWh) = (0.4*(G^2.9)*(L^0.71)*S)/(8760)	$	0.35	Variable O&M costs for catalyst: replacement & disposal
VOMP ($/MWh) =P*T*10	$	0.33	Variable O&M costs for additional auxiliary power required including additional fan power
VOMM ($/MWh) = O*U/A/1000	$	0.01	Variable O&M costs for steam
VOM ($/MWh) = VOMR + VOMW + VOMP + VOMM	**$**	**1.20**	

FINAL
BEST AVAILABLE CONTROL TECHNOLOGY/ BEST AVAILABLE CONTROL MEASURES ANALYSES TECHNICAL MEMORANDUM
FORT WAINWRIGHT, FAIRBANKS, ALASKA

PERMIT AQ1121TVP02 (REV 2, AUGUST 19, 2016)
PERMIT AQ0236TVP03 (REV 2, DECEMBER 22, 2015)

Prepared for

U.S. Army Corps of Engineers
Huntsville District

Contract W912DY-10-D-0023
Task Order 0027

Prepared by

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June 2017

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TABLE OF CONTENTS

Page

TABLE OF CONTENTS (continued)

Page

TABLE OF CONTENTS (continued)

Page

LIST OF TABLES

LIST OF APPENDICES

LIST OF ACRONYMS AND ABBREVIATIONS

ADEC	Alaska Department of Environmental Conservation
BACM	Best Available Control Measures
BACT	Best Available Control Technology
BOOS	burners out of service
BT	burner tuning
BTU	British Thermal Unit
CalEPA	California Environmental Protection Agency
CFB	coal-fired boiler
CFR	Code of Federal Regulations
CHPP	Central Heat and Power Plant
CO	carbon monoxide
CPM	condensable particulate matter
DOC	diesel oxidation catalyst
DPF	diesel particulate filter
DPPEA	Division of Pollution Prevention and Environmental Assistance
dscf	dry standard cubic foot
DU	Doyon Utilities, LLC
EGU	electric generating unit
EPA	(U.S.) Environmental Protection Agency
ESP	electrostatic precipitator
EU	Emission Unit
FDG	Flue Gas Desulfurization
FGR	flue gas recirculation
FSB	Full Stream Baghouse
FWA	(U.S. Army Garrison) Fort Wainwright
gr/dscf	grains per dry standard cubic foot
hp	horsepower
hr	hour
LAER	Lowest Achievable Emission Rate
lb/hr	pound per hour
LNB	low NOx burner
MACT	Maximum Achievable Control Technology
MACTEC	Mid-Atlantic Regional Air Management Association, Inc.
MMBTU	million BTU
MMBTU/hr	million BTU per hour
MW	Megawatt

LIST OF ACRONYMS AND ABBREVIATIONS (continued)

NO_x	Total Nitrogen Oxides
OAQPS	Office of Air Quality Planning and Standards
ODEQ	Oklahoma Department of Environmental Quality
OFA	over fire air
ORL	Owner Requested Limits
ORNL	Oak Ridge National Laboratory
OT	oxygen trim
PM	particulate matter
$PM_{2.5}$	particulate matter with a diameter less than or equal to 2.5 microns
PM_{10}	particulate matter with a diameter less than or equal to 10 microns
psi	pounds per square inch
PTE	Potential to Emit
RACT	Reasonably Available Control Technology
RBLC	RACT/BACT/LAER Clearinghouse
SCA	staged combustion air
SCR	selective catalytic reduction
SIP	State Implementation Plan
SNCR	selective non-catalytic reduction
SO_2	sulfur dioxide
TCEQ	Texas Council for Environmental Quality
tpy	tons per year
ULSD	ultra low sulfur diesel
USARAK	U.S. Army Alaska

BEST AVAILABLE CONTROL TECHNOLOGY/ BEST AVAILABLE CONTROL MEASURES ANALYSES TECHNICAL MEMORANDUM FORT WAINWRIGHT, FAIRBANKS, ALASKA

1.0 EXECUTIVE SUMMARY

This Best Available Control Technology (BACT) analysis follows the *Final Best Available Control Technology Analysis Work Plan Fort Wainwright, Fairbanks, Alaska* (HGL, 2017), which is presented in Appendix A and was submitted to the Alaska Department of Environmental Conservation (ADEC) and the U.S. Environmental Protection Agency (EPA) on April 13, 2017. The submittal is in response to ADEC's request for voluntary BACT review in advance of an anticipated Serious Nonattainment designation regarding the particulate matter with a diameter less than or equal to 2.5 micrometers ($PM_{2.5}$) from EPA. The designation was finalized 9 May 2017 with an effective date of 9 June 2017. Thus, the state of Alaska's submittal to the EPA is due 7 August 2017. This BACT process will be integral to that State Implementation Plan (SIP) submittal.

The table below lists the emission units (EUs) subject to this BACT review and the proposed BACT determinations as described within this report.

Summary Table of Proposed BACT

Pollutant	Proposed BACT Emission Limitation	BACT Device(s) or Operational Limitation(s)
Coal-Fired Boilers - 230 MMBTU/hr, DU EUs 1 through 6 Coal Combustion to be reduced to 300,000 typ, 12 month rolling totals		
• NO_x • SO_2 • $PM_{2.5}$	• 6.6 lb/ton • 0.20% Sulfur by weight in fuel, 12-month weighted average • 0.46 lb/ton	• Good Combustion Practices • Good Combustion Practices • FSB
Emergency Engines, Generators, and Fire Pumps		
• NO_x • SO_2 • $PM_{2.5}$	• Operation of certified engines and Good Combustion Practices • Good Combustion Practices and Combustion of ULSD • Good Combustion Practices and Combustion of ULSD	
Fuel Oil Boilers		
• NO_x • SO_2 • $PM_{2.5}$	• Good Combustion Practices • Good Combustion Practices and Combustion of ULSD • Good Combustion Practices	
Material Handling Sources (Coal Prep and Ash Handling)		
• $PM_{2.5}$ • $PM_{2.5}$	• Enclosed emission points and follow manufacturer recommendations for operations and maintenance.	

EU = emission unit
DU = Doyon Utilities, LLC
FSB = Full Stream Baghouse
hr = hour
MMBTU = million British thermal units (BTU)
NO_x = total nitrogen oxides
SO_2 = sulfur dioxide
tpy = tons per year
ULSD = ultra-low sulfur diesel

Implementation of BACT as described and detailed in this Analysis will result in the following net reductions in potential emissions from the significant units at Doyon Utilities, LLC (DU) and U.S. Army Garrison Fort Wainwright (FWA), as outlined below:

Potential to Emit

Source	**NO_x (tpy)**		**SO_2 (tpy)**		**$PM_{2.5}$ (tpy)**	
	Baseline	**Proposed**	**Baseline**	**Proposed**	**Baseline**	**Proposed**
Doyon Utilities, LLC						
DU-1 through DU-6	1478	990	1,764	1050	131	69
Emergency Engines, Generators, and Pumps[1]	54	32	2.8	0.22	2.63	1.7
Coal Prep 7a-7c					0.34	0.05
Ash Handling 51a-51b	0	0.00	0.00	0.00	2.83	0.42
Coal Pile					3.22	3.22
Facility Total	1533	1022	1767	1050	140	71
Fort Wainwright Garrison						
Fuel Oil Boilers	2.5	2.5	7.3	7.5	0.1	0.1
Emergency Engines, Generators, and Pumps	25.4	25.4	4.9	4.9	1.2	1.2
Waste Oil Boiler	0.42	0.42	6.44	6.44	0.34	<0.01
Facility Total	28.25	28.25	19	19	1.33	1.33
TOTAL	1561	1051	1786	1069	142	73
Reduction (tpy)	510		717		69	
% Reduction	33%		40%		49%	

tpy = tons per year

[1]Although included in this grouping, EU8 at DU is allowed to transition to a non-emergency engine once requirements under 40 Code of Federal Regulations (CFR) Part 63 Subpart ZZZZ are achieved. The engine's potential to emit (PTE) is still limited to 500 hours per year.

$PM_{2.5}$ in table above for the Fort Wainwright Garrison sources is equal to the potential particulate matter with a diameter less than or equal to 10 microns (PM_{10}) as the Fort did not provide $PM_{2.5}$ values separately.

2.0 INTRODUCTION

Fort Wainwright is a military installation located within and adjacent to the city of Fairbanks, Alaska, in the Tanana River Valley. The installation is operated by the U.S. Army Alaska (USARAK) for the purposes of training and deployment in support of USARAK's mission.

The installation includes a cantonment area of approximately 13,300 acres, which consists of the Main Post (4,475 acres) and the Range Area (8,829 acres) (SLR, 2013).

The EUs located within the military installation at Fort Wainwright are either owned and operated by a private utility company, (DU), or by FWA. The two entities, DU and FWA, comprise a single stationary source operating under two permits.

In a letter dated April 24, 2015, the ADEC requested the stationary sources expected to be major stationary sources in the $PM_{2.5}$ serious nonattainment area perform a voluntary 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, 10 May 2017, pages 21703-21706, with an effective date of 9 June 2017. This submittal is in response to ADEC's request for assistance in preparing the SIP to address the Serious $PM_{2.5}$ nonattainment reclassification.

This report addresses the significant EUs listed in the DU permit AQ1121TVP02, Revision 2 (ADEC, 2016b), and the Garrison's permit AQ0236TVP03, Revision 2 (ADEC, 2015b). The first component of the BACT determination requires the determination of baseline emissions for each EU. In nearly all cases, the baseline emissions are equivalent to the potential to emit (PTE) values as established during the most-recent Title V Operating Permit Renewal Application. Where different baseline emission rates have been determined, the basis for the calculations is provided.

The significant EUs have been grouped by type for purposes of completing the requested BACT analyses as follows:

EUs	Locations	NO_x	SO_2	$PM_{2.5}$[1]
CHPP Boilers	DU	✓	✓	✓
Emergency Engines, Pumps, and Generators	DU and FWA	✓	✓	✓
Fuel-Oil Boilers	FWA	✓	✓	✓
Material Handling	DU			✓

CHPP = Central Heat and Power Plant

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3.0 EMISSION UNITS AND POTENTIAL EMISSIONS

As described in the BACT Work Plan, presented in Appendix A of this report, a review of the PTE was the first step in the BACT evaluation. DU and FWA PTEs were based on AP-42 calculations, which can overestimate emissions. The PTE values located in Tables D of the Statement of Basis, Permits AQ1121TVP02 (ADEC, 2016a) and AQ0223TVP03 (ADEC, 2015a), submitted to ADEC by DU and FWA, respectively, are used as the potential emissions to which BACT reduction will apply, with the exception of the following:

- NO_x emission factor for DU Central Heat and Power Plant (CHPP) Boilers was revised from 8.8 lb/ton to 6.6 lb/ton to recognize the reduction in NO_x emissions as a result of the over fire air (OFA) and oxygen trim (OT) systems.
- $PM_{2.5}$ emission factor for the DU CHPP Boilers was revised from 0.78 to 0.46 lb/ton recognizing the more-recent research related to testing methodology and biases in the condensable particulate matter (CPM) measurement process and incorporating the filterable particulate matter (PM) testing from 2016.
- SO2 emission factor for DU CHPP Boilers was revised to assume 0.2% sulfur by weight in the fuel (12-month weighted average) rather than the previously assumed 0.3% sulfur by weight.
- NOx and PM emission factors for certified diesel engines were revised to reference the 40 CFR Part 60 Subpart IIII limitations which vary based on engine size and date of manufacture. (DU and FWA engines).
- Potential emissions were also impacted as horsepower (hp) rates for each of the emergency engines was confirmed.
- The proposed baseline emissions also limit coal combustion to 0.2% sulfur gross as received (12-month average) and 300,000 ton/year combusted.

Previously submitted calculations and the revised PTE for the engines at FWA are located in Appendix B. The Work Plan also describes in detail the significant EUs that will be evaluated in the BACT Analysis. Tables 3.1 and 3.2 list the significant DU and FWA EUs used in the BACT Analysis.

3.1 BOILERS

The largest EUs at the FWA installation are the CHPP boilers, owned and operated by DU. The CHPP contains six 230 million British Thermal Units (MMBTU)/hr spreader-stoker type boilers that burn Usibelli sub-bituminous coal to produce steam used for post-wide heating and power generation consumed by post activities. The six boiler's operations are currently limited by a coal combustion limit of 336,000 tons per 12-month rolling period (ADEC, 2015b).

The present CHPP configuration is the result of a major plant extension that took place in the early 1950s. The original plant consisted of two 75,000 pound per hour (lb/hr) steam capacity boilers (designated Boilers 1 and 2) and one steam turbine generator. These original boilers have been abandoned in place. The present plant consists of six 150,000 lb/hr stoker boilers (designated

Boilers 3 through 8) providing steam to three 5 Megawatt (MW) controlled-extraction steam turbines and one 5 MW 10 pounds per square inch (psi) backpressure turbine. Steam extracted from the steam turbines provides heat for the Fort Wainwright installation. The steam is discharged into a 100-psi gauge header that supplies the base steam distribution system. The distribution system is an extensive network of looped and valved steam supply and condensate return piping located in 38 miles of direct bury and utilidors. Looped and valved piping allows for isolation of problem areas and backfeeding steam from alternate directions.

Each boiler is equipped with a Full Stream Baghouse (FSB) for PM removal to levels less than 0.01 grains per dry standard cubic foot (gr/dscf). Maximum Achievable Control Technology (MACT) testing conducted in June 2016 indicated total filterable PM emissions of 0.001 to 0.006 gr/dscf for the six boilers. Using guidance from the Mid Atlantic Regional Air Management Association, Inc., (MACTEC, 2008) CPM emission rates for sub-bituminous boilers averaged 0.013 lb/MMBTU with a 95% confidence interval of ±0.002 lb/MMBTU. The Association conducted this research to more accurately define CPM emissions as determined through Method 202 testing while correctly applying the nitrogen purge to minimize the overestimation of sulfate-based CPM. Using this information from MATEC, this equates to 0.009 to 0.015 gr/dscf for total filterable and CPM from the boilers. For consistency with the other emission factors, DU recommends 0.46 lb/ton coal combusted be used as the emission factor for calculating $PM_{2.5}$ emissions. Calculations are provided in Table 3.3.

Each fabric filter includes five modules with 210 separate bags per module (i.e., 1,050 total filter bags per FSB). PM-laden boiler combustion gas enters at the base of each module, is dispersed by a series of baffles, rises through the filter media, and exits the module at the top of the unit. Each FSB is a pulse jet-type fabric filter and is designed to allow for both on-line and off-line cleaning. Each boiler stack is equipped with a continuous opacity monitoring system for monitoring the FSB effectiveness at meeting the permitted opacity limit (SLR, 2013). The boilers are currently limited to PM emissions of 0.05 gr/dscf averaged over a 3-hr averaging period, see Condition 7.1 of Permit AQ1121TVP02 (ADEC, 2016b). The boilers are additionally subject to the MACT Subpart DDDDD filterable PM standard of 0.04 lb/MMBTU heat input. Compliance with the MACT limit was demonstrated during the 2016 MACT test.

In addition to the FSB for PM control, the boilers are each equipped with OT combustion control. OT reduces NO_x by (1) suppressing thermal NO_x by partially delaying and extending the combustion process resulting in less intense combustion and cooler flame temperatures; and (2) suppressing fuel NO_x formation by reducing the concentration of air in the combustion zone where volatile fuel nitrogen is evolved. OT can reportedly reduce NO_x by 10% to 20% from uncontrolled levels (EPA, 1998). Additionally, the burners are operated with OFA which additionally reduces NO_x formation as discussed later in this report.

The six boilers are not operated simultaneously. The normal operations of the utility require three to four boilers to be operational while the remainder are being maintained offline. The facility requires the flexibility to respond to any demand from FWA and thus maintains all six in a state of readiness.

Emission factors used for the baseline conditions in this BACT analysis for the CHPP Boilers are as follows:

Pollutant	Value	Unit	Notes
CHPP Boilers			
NO_X	6.6	lb/ton coal combusted	AP-42 tables 1.1.3 with OT and OFA control assumed to reduce emissions by 25% (Table 1.1.2 of AP-42 indicates range of 20%-30% control). Total NO_x limited by coal combustion limit. OT use is enforceable as it is required to achieve carbon monoxide (CO) emission limits associated with 40 CFR Part 63 Subpart DDDDD. DU is willing to accept this value as an Owner Requested Limits (ORL) in the event the precursor analysis completed by ADEC as part of the SIP process indicates NO_x reductions from the stationary sources will have a material impact on the $PM_{2.5}$ 24-hr standard compliance. In the event such a relationship is not identified, DU will not propose any changes to the existing NO_x limitations or coal combustion rates currently present in the permit.
SO_2	0.20	Weight percent, 12-month average	AP-42 1.1-3 based. Facility data indicates weighted average sulfur content of coal is 0.13% for 2016. Usibelli reports a Gross As Received range of 0.08% to 0.28%. DU is willing to accept this value as an ORL in the event the precursor analysis completed by ADEC as part of the SIP process indicates SO_2 reductions from the stationary sources will have a material impact on the $PM_{2.5}$ 24-hr standard compliance. In the event such a relationship is not identified, DU will not propose any changes to the existing SO_2 limitations or coal combustion rates currently present in the permit.
$PM_{2.5}$	0.46	lb/ton coal combusted	See discussion above regarding the FPM testing completed for MACT demonstration and 2008 guidance to the Mid Atlantic Regional Air Management Association related to CPM emissions.
Cumulative for all CHPP Boilers			
ALL	300,000	Ton/year coal combusted	Permit Condition 12.1 currently limits coal combustion to 336,000 tons/year. Because of changing operations, the Fort does not expect to need more than 300,000 tons/12-month period in the future. DU is willing to accept this reduction in coal combustion in support of the region's efforts to achieve attainment status with the 24-hr $PM_{2,5}$ standard.

3.2 EMERGENCY ENGINES, FIRE PUMPS, AND GENERATORS

Both the DU and FWA permits include emergency engines for fire pumps, wells, and generators. For purposes of determining baseline emissions, FWA has assumed 500 hrs per year in accordance with EPA Guidance (Seitz, 1995). Emission factors have also been updated to reflect the 40 CFR Part 60 Subpart IIII limits applicable to subject engines and have used manufacturer information in lieu of AP-42 where available.

3.3 FUEL OIL BOILERS LOCATED AT FWA

FWA Title V permit (ADEC, 2015b) includes three 19 MMBTU/hr fuel oil-fired boilers and one waste oil 2.5 MMBTU/hr boiler. The 19 MMBTU/hr boilers operate only if CHPP is unable to deliver steam to necessary infrastructure. The 2.5 MMBTU/hr boiler combusts used oil from vehicle maintenance.

3.4 MATERIAL HANDLING

The DU facility includes material handling EUs associated with the transport and transfer of the coal and ash. Significant coal handling EUs included in this BACT analysis include the South Coal Handling Dust Collector (EU 7a); the South Under-Bunker Dust Collector (EU 7b); the North Coal Handling Dust Collector (EU 7c). These EUs are currently subject to a PM limitation of 0.1 gr/dscf, 3-hr average, permit condition 7.2. (ADEC, 2016b). Significant ash handling sources include the Flyash Dust Collector (EU 51a) and the Bottom Ash Dust Collector (51b). Photos of these EUs are included in Appendix C. The Coal Pile is also considered in this BACT analysis (EU 52).

Tables D-3.7a through 7c from the facility's Title V Permit (ADEC, 2016b) renewal application document actual emissions from these EUs during 2011 and 2012. Tables D-1.7a through 7c document assessable potential emissions. As documented within the permit application, the coal and ash handling activities do not operate continuously. For purposes of the BACT analysis of these EUs, the following baseline conditions are employed:

EU	Parameter	Value and Units	Notes
7a	Grain loading in exhaust	0.0025 gr/dscf (2003)	This grain loading was identified through testing. For purposes of calculating $PM_{2.5}$, this BACT analysis assumes 2195 hrs/year and that 15% of PM emissions are $PM_{2.5}$. This overstates PM2.5 emissions from this source.
7b	Grain loading in exhaust	0.02 gr/dscf	Manufacturer guarantee for PM greater than 2 microns. Because this is a coal source, $PM_{2.5}$ is not anticipated. As a conservative assumption, the 0.02 gr/dscf is assumed to be representative of $PM_{2.5}$ emissions.
7a	Hrs/year	2195 hrs/year	As established in the Title V Permit renewal application.
7b	Hrs/Year	100 hrs/year	This unit operates only if the coal bunker needs to be emptied resulting from a boiler shut down or as a safety device in the event of a bunker fire. Because the facility conducts continuous maintenance on its boilers, this unit does not operate more than 100 hrs/year. The Title V Permit renewal application set PTE for this unit at 100 hrs/year.
7c	Hrs/year	45 hrs/year	This is the backup system to EU No. 7a. It operates less than 2% of the time. The Title V Permit renewal application set PTE for this unit at 45 hrs/year and assumes 0.02 gr/dscf as representative.

dscf = dry standard cubic foot

The CHPP generates approximately 19,000 tons of coal ash annually. Six to eight truckloads of ash are removed from the CHPP to the on-site landfill daily.

The CHPP maintains an on-site reserve of approximately 22,500 tons of coal. The pile is only used when there is an interruption in coal delivery or in the event the rail unloading system requires maintenance.

3.5 POTENTIAL TO EMIT SUMMARY

Tables D through F in the Statement of Basis for DU (ADEC, 2016a) and FWA (ADEC, 2015a) lists the following PTE values.

Source/Pollutant	NO_x (tpy)	SO_2 (tpy)	$PM_{2.5}$
DU	1533	1767	124.3
FWA	42	30	21[a]
TOTAL	**1575**	**1797**	**145**

[a] Listed in Table E as PM_{10}/PM. $PM_{2.5}$ not presented separately for Ft. Wainwright Garrison.

As presented within this Report, the base case PTE for the two facilities is revised as follows:

Source/Pollutant	NO_x (tpy)	SO_2 (tpy)	$PM_{2.5}$
DU	1,533	1,764	140
FWA	28	19	1.3
TOTAL	**1,561**	**1,783**	**142**

BACT reductions will be based on the revised PTE as presented above.

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4.0 BACT ANALYSIS METHODOLOGY

BACT establishes an emissions limitation based on the maximum reduction that is achievable for each pollutant subject to ADEC's BACT request (NO_x, SO_2, and $PM_{2.5}$). The analysis takes into account, on a case-by-case basis, technical feasibility as well as energy, environmental, and economic impacts. The FWA and DU significant units, as identified in Tables 3.1 and 3.2, are considered within the state-requested BACT analysis. Each BACT analysis proceeds in a manner consistent with EPA's top down approach:

Step 1 – Identify all available control technologies for each significant source and each pollutant subject to review

Step 2 – Determine technical feasibility of potential technologies

Step 3 – Rank control technologies by control effectiveness

Step 4 – Evaluate most effective controls and document results

Step 5 – Select BACT

Each of these steps is discussed in further detail below.

4.1 STEP 1 – IDENTIFY ALL AVAILABLE CONTROL TECHNOLOGIES

The first step in a "top-down" analysis is to identify, for all applicable EUs, all "available" control options. Available control options are defined as those air pollution control technologies or techniques that have a practical potential for application to the emissions unit and the regulated pollutant under evaluation and have been demonstrated in practice. Air pollution control technologies and techniques include the application of production processes or available methods, systems, and techniques, including innovative fuel combustion techniques and add-on controls.

4.2 STEP 2 – DETERMINE TECHNICAL FEASIBILITY OF AVAILABLE TECHNOLOGIES

In the second step, the technical feasibility of the control options identified in Step 1 are evaluated with respect to source-specific factors. A demonstration of technical infeasibility should be documented and should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the EUs under review. Technically infeasible control options are then eliminated from further consideration in the BACT analysis.

4.3 STEP 3 – RANK CONTROL TECHNOLOGIES BY CONTROL EFFECTIVENESS

All remaining control alternatives not eliminated in Step 2 are ranked, then listed in order of overall control effectiveness for the pollutant under review with the most effective control alternative at the top. A list is then prepared for each pollutant and for each EU (or grouping of similar units) subject to a BACT analysis.

4.4 STEP 4 – EVALUATE MOST EFFECTIVE CONTROLS AND DOCUMENT RESULTS

After the identification of available and technically feasible control technology options, the energy, environmental, and economic impacts are considered in this step. For each control option an objective evaluation of each impact is presented. Both beneficial and adverse impacts should be discussed and, where possible, quantified. If the applicant accepts the top alternative in the listing as BACT, the analysis is ended and the result is selected as BACT. In the event the top candidate is shown to be inappropriate due to energy, environmental, or economic impacts, the rationale for this finding is documented and the next level of control is analyzed.

4.4.1 Cost Analysis Methodology

When considering the economic impacts of a control technology, the EPA Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual (2002) approach to calculating cost has been used as a framework. Specific assumptions are presented within the applicable sections. Equipment life assumptions apply to the entire facility and are presented below.

4.4.2 Equipment Life Assumption Basis

The BACT analysis for all control technologies assumes a 10-year useful life. In 2007, as part of the Utilities Privatization effort, the Army transferred the ownership and operation of the CHPP to DU. DU, operating under a Federal Acquisition Regulation contract, is a utility company whose rates are regulated by the Regulatory Commission of Alaska. As such, there is a special relationship between the U.S. Government and DU – a utility company serving only ‘one’ customer (the U.S. Government). The contract between DU and the U.S. Government requires DU to obtain approval from the U.S. Government before initiating any capital projects for which a rate increase would be required.

At present, DU CHPP is nearing the end of the useful design life cycle. Recently, an executive committee was formed with members from the U.S. Army and DU Utilities to identify the best possible options to meet the future heat and electricity requirement for FWA. The committee will review various requirements including but not limited to: the Army mission, energy security requirements, regulatory requirements, and fuel security requirements. The committee will recommend a path forward to provide a reliable and cost-effective mechanism to meet the future heat and electricity requirements for FWA. Once this is accomplished, the Army leadership will decide on the best possible option. At present, the contract between DU and the Army has a plan to replace the existing boilers with new Fluidized Bed Combustion boilers and new turbines in 2026. Although there is not yet a firm future plan, this BACT analysis assumes the existing boilers and the associated equipment will be demolished when the new boilers and turbines are installed. Therefore, a design life of 10 years has been used for all equipment considered under the BACT analysis.

DU and Fort Wainwright recognize this assumption is inconsistent with OAQPS guidance; however, any control devices employed for this facility will be highly customized and tailored to retrofit to the particular constraints of Fort Wainwright’s equipment. Additionally, any retained value as "Used Equipment" at the end of the 10-year period would be difficult to capture. The freight costs from Fairbanks make reselling used equipment unlikely.

4.5 STEP 5 – PROPOSED BACT

The final proposed BACT is presented in this step.

EPA ranks technologies for pollution reduction into the following, listed from most stringent to least stringent:

- Lowest Achievable Emission Rate (LAER)
- BACT
- Reasonable Available Control Technology (RACT)

EPA maintains the RACT/BACT/LAER Clearinghouse (RBLC), which documents information pertaining to Prevention of Significant Deterioration air permits issued in the United States. LAER is the most-stringent limit or standard of performance that is achievable by a source. LAER determinations are completed without regard to economic impacts (with limited exceptions). In the process of building a new facility, a source that elects to install LAER has no further analysis to perform.

Additionally, the BACT determination is considered complete when a source selects the most-stringent limitation found within the RBLC dataset for similar sources.

The final BACT determination is completed by the state regulatory agency and is Federally enforceable.

This format of this analysis will group the EUs and evaluate each pollutant, NO_x, SO_2, and $PM_{2.5}$. For each combination of EU and pollutant, the five-step top-down process will be used.

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5.0 COAL-FIRED BOILERS

The BACT review for the six coal-fired boilers (CFBs) owned and operated by DU considers BACT available to the EUs as they exist. In a preconstruction process, BACT would be completed during the engineering and design work. Space for control systems would be anticipated; pressure, temperature, and interactions would be considered; and source determinations could be made with the overall limitations and emission requirements understood.

This BACT process attempts to retroactively determine what technologies might be employed to an operating facility that would reduce emissions of $PM_{2.5}$ and its precursors. In addition, the technological limitations inherent in working with the type and age of boilers found at Fort Wainwright introduce complexity and challenges.

The source description for these boilers is as follows:

- EU numbers 1 through 6 – each is a 1953 spreader stoker boiler combusting sub bituminous coal from the Usibelli mine south of Fairbanks.
- OT was added to the boilers during the period between 2010 and 2014. All the boilers were tuned in 2014.
- OFA is used in the combustion process.
- Each boiler has a maximum heat rating of 230 MMBTU/hr.
- The boilers are currently limited to a total coal combustion limit of 336,000 tons coal annually.
- At maximum capacity, the boilers produce 150,000 lbs steam per hr. The boilers normally operate at 110,000 lbs steam/hr.
- The current assessable PTE estimate for these boilers uses an AP-42 emission factor of 8.8 lbs/ton. In this report, the potential to emit calculation is reduced to 6.6 lbs/ton by utilizing a 25% NO_x reduction to the 8.8 lb/ton value as a result of the OFA and OT systems (EPA, 1998).

Additionally, DU prepared a site-specific analysis to assist ADEC with the required NO_x RACT analysis for the moderate $PM_{2.5}$ Nonattainment SIP (Coiley, 2016).

As explained in the October 2016 correspondence, the boilers are currently controlled with FSB and OT systems. As they are less than 25 MW, the units are considered industrial rather than electric utility units.

5.1 BACT FOR NITROGEN OXIDES (NO_X)

The BACT Analysis for the CFBs for NO_x follows the top down approach outline in Section 4.0.

NO_x is primarily formed in combustion processes in two ways:

1. The combination of elemental nitrogen with oxygen in the combustion air within the high temperature environment of the combustor (thermal NO_x).
2. The oxidation of nitrogen contained in the fuel (fuel NO_x).

Control of NO_x emissions from combustion is generally aimed at either the prevention of NO_x formation or the capture and oxidation of post-combustion NO_x. Because the rate of formation of thermal NO_x is a function of residence time and free oxygen and is exponential with peak flame temperature, "front-end" control techniques are aimed at controlling one or more of these variables.

Although reducing excess oxygen and decreasing the resident time at high temperature will reduce NO_x formation, these changes also influence boiler performance. Oxygen and temperature are important flame parameters that affect stability, heat release, combustible burnout, flame appearance, and other operating factors.

Other control methods utilize add-on control equipment to remove NO_x from the exhaust gas stream after its formation. The most common control techniques involve the injection of ammonia or urea into the gas stream to reduce the NO_x to molecular nitrogen and water. Ammonia can either be injected into the system without the use of a catalyst (selective non-catalytic reduction [SNCR]) or with the use of a catalyst Selective Catalytic Reduction (SCR).

5.1.1 Step 1 – Identify All Available Control Strategies

Potential control strategies were identified through industry research and the RBLC maintained by EPA. Through this research, the technologies to be considered in this analysis are as follows:

5.1.1.1 <u>Selective Non-Catalytic Reduction</u>

It has been reported that SNCR was successfully used with spreader stoker boilers. Table 5.12 in EPA's "Alternative Control Techniques Document" (EPA, 1994) indicates SNCR using ammonia can achieve controlled NO_x emission levels of 0.15 to 0.18 lb/MMBTU. SNCR utilizing urea can achieve controlled NO_x emission levels of 0.14 to 0.28 lb/MMBTU. This post-combustion process has associated ammonia slip emissions, which are also a precursor for $PM_{2.5}$. Temperature for these operations are very important with the window of operation between 1,400°F and 2,000°F, but temperatures above 1,700°F are preferred (Oak Ridge National Laboratory [ORNL], 2002). Mechanical components required to implement this system include storage and handling equipment, mixing equipment, and injection equipment. Like SCR, the formation of salts as a result of ammonia slip is an undesirable consequence of SNCR that can cause the formation of fine PM, fouling, and corrosion.

5.1.1.2 <u>Selective Catalytic Reduction</u>

NO_x emissions are reduced as the reductant (ammonia gas) is injected into the flue gas before it passes through a catalyst bed. This technique disassociates the NO_x to nitrogen and water vapor (ORNL, 2002). The application can be used where exhaust gas temperatures fall between 350°F and 1,200°F and are typically between 450°F to 850°F (ORNL, 2002). EPA's Section 4, Chapter 2, of the Air Pollution Cost Control Manual (EPA, 2016) present an effective temperature range of 480°F to 800°F. Ammonia slip presents the potential for the formation of sulfur trioxide reactions and the formation of ammonia salts. These salts are sticky and corrosive and can potentially cause downstream plugging issues. Additionally, the ammonia slip may impact the fly ash properties. Catalyst poisoning, plugging, and erosion also are possible.

SCR can reportedly achieve 0.2 lb/MMBTU for stoker boilers (State and Territorial Air Pollution Program Administrators and Association of Local Air Pollution Control Officers, 1994).

5.1.1.3 Combustion Control

Several modifications are available that minimize the amount of excess oxygen supplied to the boiler, which reduces thermal NO_x formation. OT, burner tuning (BT), and LEA approaches can sometimes successfully optimize the burners without excessively increasing unburned fuel (ORNL, 2002). Stoker boilers do not have burners; therefore, BT is not applicable. OT is already successfully deployed on these boilers.

Through the OT system, DU is already minimizing the excess air at combustion. Per EPA's detailed report EPA-600/8-81-016, "A Guide to Clean and Efficient Operation of Coal-Stoker-Fired Boilers (EPA, 2004):

> *"….in stoker-boilers, the operator is doing well to keep the oxygen in the 5-7% range."*

As shown in the 2016 MACT testing, the oxygen ranged from 4.5% to 5.5% by volume, which is on the lower end of the expected oxygen levels within a stoker boiler employing OT. As suggested in the EPA report (EPA, 2004), lower oxygen levels translate into lower nitrogen and NO_x levels.

5.1.1.4 Low NO_x Burners

Low NO_x Burners (LNBs) are not applicable to stoker boilers and are therefore not an available control technology.

5.1.1.5 Staged Combustion Air

Staged Combustion Air (SCA) includes burners out of service (BOOS) and OFA approaches.

BOOS are not available options for spreader stoker boilers.

The OFA approach reduces combustion air under the grate and increases OFA. There is danger of grate overheating, clinker formation, corrosion, and high CO emissions (EPA, 1994). EPA's 1994 data included five spreader stoker units with SCA employed. The average NO_x emission was 0.42 lb/MMBTU. Use of SCA with coal-fired units is effective as it reduces the formation of fuel-bound NO_x (ORNL, 2002).

OFA technology can achieve NO_x reduction on the order of 20 to 45% (Power Engineering, 2015). The boilers already have OFA installed (see photos in Appendix D).

5.1.1.6 Good Combustion Practices

DU commits significant time and resources to preventive maintenance and operational support of the CHPP boilers. The tune ups associated with the MACT and operational procedures are employed and minimize emissions of all pollutants to the atmosphere.

5.1.2 Step 2 – Identify Technically Feasible Control Technologies

Each control technology identified in Section 5.1.1 is evaluated for feasibility.

5.1.2.1 Selective Non-Catalytic Reduction

SNCR is a post-combustion NO_x control technology in which a reagent (ammonia or urea) is injected into the exhaust gases to react chemically with NO_x, forming nitrogen and water. The success of this process in reducing NO_x emissions is highly dependent on the ability to uniformly mix the reagent into the flue gas at a zone in the exhaust stream at which the flue gas temperature is within a narrow range, typically from 1,700°F to 2,000°F. To achieve the necessary mixing and reaction, the residence time of the flue gas within this temperature window should be at least 0.5 to 1.0 seconds.

The consequences of operating outside the optimum temperature range are severe. Outside the upper end of the temperature range, the reagent will be converted to NO_x. Below the lower end of the temperature range, the reagent will not react with the NO_x and the ammonia slip concentrations (ammonia discharge from the stack) will be very high. The flue gases from the boilers at Fort Wainwright have an exhaust temperature of approximately 300°F (Air Source Testing, Inc, 2010). Even strategically placing the ammonia injection further upstream would likely result only in peak temperatures of around 1,300°F. Such a low temperature would require that additional fuel be combusted at some point to raise the temperature to the levels that SNCR will be successful. Combustion of the additional fuel would not only increase the NO_x emissions but also all other criteria pollutants, especially CO and $PM_{2.5}$ (in the form of ammonia). In addition, the added fuel used to raise the exhaust gas temperature will increase the annual operating costs for the facility.

According to the RBLC database (see Table 5.1 CHPP RBLC - NO_x), SNCR has not been applied to any coal-fired spreader stoker. SNCR is specified for a greenfield ethanol plant, which utilized coal for its energy source. The 2008 permit represents LAER for CFB. The emission limit specified within RBLC is 0.1 lb/MMBTU over 24-hr averaging periods.

As DU presented in the NO_x RACT correspondence in October 2016 (see Appendix E), implementing SNCR would require a considerable amount of heat to achieve the specified temperature range, especially given the number of days on which subzero temperatures occur. Generating energy for heating would require additional fuel combustion resulting in additional emissions of direct $PM_{2.5}$ and $PM_{2.5}$ precursors. Ammonia is more toxic than NO_x and is classified by EPA as a hazardous material.

EPA's Air Pollution Cost Control Manual (EPA, 2002) states:

> "*SNCR is not suitable for sources where the residence time is too short, temperatures are too low, NO_x concentrations are low, the reagent would*

> *contaminate the product, or no suitable location exists for installing reagent injection ports."*

Hence, **SNCR is considered technically infeasible for the CHPP boilers** because of the temperature differential of the stack gas as compared to the recommended SNCR operating range.

Even though considered technically infeasible for this installation, DU utilized the SNCR cost estimating tools published by EPA in May 2016 to consider the economic viability of the control technology.

The Data Input tab details the parameters considered and the values assumed. DU selected a retrofit factor of 1.5 because of the tight location constraints, the short construction season, the impact of unknown construction details and infrastructure that may not be located correctly on as-builts, and the necessary additional support for ducting and air flow that are not captured in a traditional BACT cost review.

Based on the quote provided by Fuel Tech, see Appendix F, and using EPA's template, this technology is estimated to cost almost $18,000/ton NO_x removed. See Appendix G, for the completed EPA Air Pollution Control Estimating Spreadsheet for SNCR (May 2016).

Based on both EPA's report, the vendor quote, and EPA's cost template, SNCR is considered technically infeasible.

5.1.2.2 <u>Selective Catalytic Reduction</u>

SCR is a post-combustion technology that employs ammonia in the presence of a catalyst to convert NO_x to nitrogen and water. The function of the catalyst is to lower the activation energy of the NO_x decomposition reaction. Technical factors related to this technology include the catalyst reactor design, optimum operating temperature, sulfur content of the fuel, de-activation due to aging, ammonia slip emissions, and the design of the ammonia injection system.

A disadvantage of this system is that particles from the catalyst may become entrained in the exhaust stream and contribute to increased PM emissions. In addition, ammonia slip reacts with the sulfur in the fuel creating ammonia bisulfates that become PM. Finally, the temperature of the exhaust will still require additional heating. No application of SCR on spreader stoker boilers as retrofit applications was identified.

The EPA Air Pollution Control Estimating Spreadsheets for SCR (May 2016) was completed. This analysis reveals the SCR costs for NO_x control exceed $25,000/ton removed. Even if the technology was technically feasible for this installation, the cost of the system renders its selection infeasible on economic review.

5.1.2.3 <u>Combustion Control and Good Combustion Practices</u>

The currently installed OFA and OT systems are technically feasible and successfully deployed emission control pathways. EPA data indicates these approaches can reduce NO_x from 15% to 45%. Additionally, DU already conducts robust preventive maintenance on the boilers allowing the boilers to minimize excess oxygen and to operate consistently.

5.1.2.4 Summary of the Technically Feasible Control Options

Technically-feasible NO_x control options for the spreader stoker boilers are summarized below. The expected performance has been determined considering the performance of existing systems and published data indicating controls to be achieved.

In a letter to ADEC regarding RACT for the Boilers dated October 2016, DU cited EPA data indicating an average uncontrolled NO_x emission rate of 0.53 lb/MMBTU for spreader stoker boilers (EPA, 1994). More-recently, EPA published data from a 1999 report on coal-fired power plants identifying 15 uncontrolled stoker style coal-fired units with an average NO_x emission rate of 0.40 lb/MMBTU (EPA, 2005).

With the OT and OFA, DU has estimated EUs 1 through 6 emissions of 0.41lb/MMBTU:

8.8 lb/ton from AP-42 Table 1.1.3 (9/98) *(1-0.25) = 6.6 lb/ton

6.6 lb/ton * ton/2000 lbs *lb/7200 BTU * 1e 6 BTU/MMBTU = 0.46 lb/MMBTU (low heat rate)

6.6 lb/ton * ton/2000 lbs *lb/8000 BTU * 1e 6 BTU/MMBTU = 0.41 lb/MMBTU (low heat rate)

Control System	Expected Performance (lb/MMBTU) or Impact	Technical Feasibility	Comments
Combustion Controls and Good Combustion Practices			
OT	Reduce NOx 10-30%% (DPPEA,1998)	Yes – Currently in place	Added between 2010 and 2014 to minimize CO emissions and comply with Boiler MACT.
OFA	Reduce NOx 20-45%	Yes – Currently in place	See photos of OFA systems in Appendix D
Post Combustion Controls			
SCR	0.2 lb/MMBTU	Feasible	There is no record of SCR in use with spreader stoker coal-fired units.

DPPEA = Division of Pollution Prevention and Environmental Assistance

5.1.3 Step 3 – Rank the Technically Feasible Control Technologies

Add-on controls may be used for coal combustion.

The technically feasible NO_x control technologies for the combustion turbine are ranked by control effectiveness are listed below:

Control Technology	Controlled NO_x Emission Level (lb/MMBTU)
SCR	0.2
OT + OFA + Good Combustion	0.46

5.1.4 Step 4 – Evaluate the Most Effective Controls

Since DU already employs OT and OFA, this section will only evaluate SCR.

5.1.4.1 Selective Catalytic Reduction

Energy Impacts

An SCR system results in a loss of energy due to the pressure drop across the SCR catalyst. To compensate for the energy loss in the SCR system, additional coal combustion is required to maintain the net energy output, which also results in additional air pollutant emissions. The flue gas would require reheating, which also increases operational costs. This energy impact is especially important given the number of days on which subzero temperatures are encountered at the Garrison. Power is also required for pumping and heating the ammonia.

Environmental Impacts

SCR systems consist of an ammonia injection system and a catalytic reactor. Urea can be decomposed in an external reactor to form ammonia for use in a SCR. Unreacted ammonia may escape through to the exhaust gas. This is commonly called “ammonia slip,” and it is not uncommon for the slip to be up to 10 parts per million, which may be considered an environmental impact. The ammonia released may also react with other pollutants in the exhaust stream to create fine particulates in the form of ammonium salts. In addition, storing the ammonia on site is another environmental and safety concern. SCR catalysts must also be replaced on a routine basis. In some cases, these catalysts may be classified as a hazardous waste. This typically requires either returning the material to the manufacturer for recycling and reuse or disposal in designated landfills.

Economic Impacts

In addition to the power requirements for heating the flue gas, pumping the ammonia, heating the ammonia, and compensating for the pressure drop across the catalyst, SCR implementation will require an additional structure to house the flue-gas reheating system, the catalyst bed, and other SCR-related components. Additional building space may be available west of the existing baghouse structure; however, installation and connections to the existing infrastructure will be challenging and will require relocating an existing paved road and buried utilities as well as redesigning the storm drainage system.

Retrofitting the SCR system into the current footprint will be significant. DU has assumed a retrofit factor of 1.5 because of the following factors: the location of this site in Alaska; the short construction seasons; the age of the equipment being controlled; the infrastructure that will need to be rerouted; and the addition of catalyst housings, gas handling, controls, and chemical storage and mixing. Using EPA’s cost manual spreadsheet and the assumptions as detailed in Appendix H, SCR Cost Manual, DU estimates the cost of SCR controls to be greater than $21,000/ton for NO_x to be removed. This factor is likely still a low estimate as the placement of the SCR following the baghouse would require reheating the exhaust gas.

5.1.5 Step 5 – Proposed NO_x BACT Determination

These boilers are subject to the Boiler MACT. As part of the MACT, the boilers require tune ups every five years (Permit Condition 42.3d) and periodic testing to confirm good combustion practices. The capital, retrofit, and operational costs of SCR along with the potential for increased $PM_{2.5}$ emissions from ammonia slip lead DU to conclude that its selection as BACT is not warranted.

Combustion controls of OFA + OT + Good Combustion Practices are selected as BACT for NO_x control. DU proposes a BACT limit of 0.46 lb NO_x/MMBTU. Compliance to be demonstrated annually based on average of three one-hour tests.

5.2 BACT FOR SO_2

Sulfur in most fossil fuels is derived from the decay of plant and animal matter. It can also originate from iron sulfite and iron sulfate.

Combustion of sulfur-bearing fuel results in the creation of SO_2. Switching to low-sulfur coals can be an effective way to reduce SO_2 emissions. For the Fort Wainwright operation, the locally available sub-bituminous coal from the Usibelli mine is relatively low in sulfur with guarantees of less than 0.4% by weight. Usibelli Coal Data Sheets, see Appendix I, indicate a range of 0.08% to 0.28% Gross As Received %S. Actual shipment data indicates a weighted annual average of 0.13% sulfur by weight (2016). This annual average value equates to 0.30 SO_2 lb/MMBTU using EPA's AP-42 emission factor for SO_2 for spreader stoker boilers. The calculation is presented below.

35*0.13 lb S/ton * ton/2000 pounds * lb coal/7572 BTU * 1e6 BTU/MMBTU = 0.3 lb SO_2/MMBTU

Using the maximum range as provided by Usibelli, the annual average SO_2 emission rate equals 0.65 lb SO_2/MMBTU. For purposes of this BACT determination, 0.65 lb/MMBTU will be assumed to be the base case.

5.2.1 Step 1 – Identify Potential Control Strategies

SO_2 emissions are a function of sulfur in the fuel. Strategies to reduce the formation of SO_2 include the following:

- Using low-sulfur coal
- Wet Scrubbers
- Semi-Dry Scrubbers
- Dry scrubber

Wet and dry scrubbers employ a variety of sorbents and injection methodologies to react with the SO_2 in the flue gas creating a precipitate that is then captured in a particulate control device (dry) or as a slurry (wet).

In a wet scrubber system, flue gas is ducted to a spray tower where an aqueous slurry of sorbent (usually lime or calcium-based) is injected into the flue gas. The nozzles and injection locations are designed to optimize the size and density of the droplets. A portion of the water in the slurry is evaporated, and the waste gas stream becomes saturated with water vapor. The SO_2 dissolves into the slurry and reacts with the alkaline particulates. The slurry falls to the bottom of the absorber where it is collected. The flue gas then passes through a mist eliminator. The absorber effluent is sent to a reaction tank where the reaction is completed forming a neutral salt.

In semi-dry scrubbers, 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 (ESP).

Dry sorbent injection systems 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 ESP. The flue gas is generally cooled prior to entering the PM control device (EPA, 2003b).

5.2.2 Step 2 – Identify Technically Feasible Control Technologies

If low-sulfur coal is not an option, ORNL's 2002 report presents wet or dry scrubbers as viable options.

The RBLC database, see Table 5.2, CHPP RBLC – SO_2, provides two SO_2 control technologies for consideration. Both were associated with Electric Generating Units (EGUs) Best Available Retrofit Technology reviews:

- Limestone Injection and Add on Dry Flue Gas Desulfurization FGD
- FGD and Scrubber

FGD systems are comprised of two stages: one for fly ash removal and the other for SO_2 removal. Wet scrubbing systems usually pass through a fly ash removal step (ESP or baghouse), then proceed to the SO_2 absorber. Dry systems operate with SO_2 reacting with the sorbent first (usually calcium and sodium based alkaline reagents), then remove the precipitate in the baghouse.

However, for the dry system to work properly the flue gas must be cooled to 20°F to 50°F below the saturation temperature (EPA, 2003b). This temperature range is important for protecting the downstream equipment, including the full stream baghouse, from wet solid plugging issues. These systems likely include additional or upgraded induced draft fans to compensate for pressure drop across the absorber as well as a heat exchanger or evaporative cooler for cooling the gas.

Control System	Expected Performance lb/MMTBU	Comments
Low Sulfur Coal	0.60 lb/MMBTU	Assumes 0.28% S by weight in the fuel (the high end of the Usibelli Coal information)
Post Combustion Control		
Wet Scrubber	90%	High capital and operating costs due to handling of liquid reagent and waste (EPA, 2003)
Semi Dry Scrubber	80% to 90%	
Dry Scrubber	50% to 80% removal[1]	No water demand, use less space than wet systems, simpler to operate than wet systems.

[1](EPA, 2003)

5.2.3 Step 3- Rank the Technically Feasible Control Technologies

The technically feasible SO_2 control technologies for the CHPP boilers are ranked by control effectiveness below:

Control Technology	Maximum Reduction (%)	Controlled SO2 Emission Level (lb/hr)
Wet Scrubber	90%	0.07 lb/MMBTU
Semi Dry Scrubber	90%	0.07 lb/MMBTU
Dry Scrubber	80%	0.13 lb /MMBTU
Lower Sulfur Coal	30%	0.49 lb /MMBTU
Low Sulfur Coal	Base Case	0.6 lb /MMBTU

5.2.4 Step 4 – Evaluate the Most Effective Control

The next step is to review each of the technically feasible control options for environmental, energy, and economic impacts.

5.2.4.1 <u>Wet Scrubber</u>

Energy Impacts

The Wet scrubber system will require additional energy for the pumps, blowers, and conveying equipment. This, in turn, will require additional coal combustion to provide the necessary energy. With additional combustion, additional $PM_{2.5}$ is emitted along with its precursors.

Environmental Impacts

Limestone or lime will need to be stored onsite. As a retrofit application, the facility has space and siting constraints for both the raw material and the prepared sorbent. Per EPA, "Electrical utilities store large volumes of limestone or lime on site and prepare the sorbent for inject, but this is generally not cost effective for smaller industrial applications." (EPA, 2003). This control technology also creates a waste stream that must be handled and disposed of appropriately. Gypsum by-product may be a commercially viable product; however, at this location in Alaska, the more likely scenario will be disposal of the byproduct as transportation costs would be significant.

Wet Scrubber systems suffer from an acid environment leading to corrosion and abrasion. The flue gas and equipment must be protected with linings or resistant materials.

Economic Impacts

Wet scrubber systems have a high capital and operating cost due to the handling of reagents and waste products (EPA, 2003). Retrofit scrubbers are much more expensive. The impact on the boiler's operation through additional pressure drop will also lead to additional combustion to compensate.

Wet scrubbers have complex and challenging operational considerations. The process variables are subject to change, including the reactivity of the lime or limestone, the reaction time, the pH, and the inlet SO_2. These process variables are also impacted by temperature, and the sub-Artic environment makes temperature concerns significant (Neveceral, 2015). Scale build up in the system is possible and protecting the system from freezing would require additional heating needs from the plant.

A wet scrubber system would require significant amounts of water. The benefit of SO_2 reductions must be balanced against using the water resources.

The Fort is required to maintain a constant state of readiness. Thus, the risks associated with operating a wet scrubber system in the sub-Arctic environment precludes its choice as a control device for the Fort.

Cost estimates for wet scrubber systems were estimated by Andreas Poullikkas (Poullikkas, 2015) to have capital costs of $191 to $316/kW for capital costs and 0.78 cents to 1.56 cents/kWh for operating expenses. Converting to a $/ton removed cost suggests wet scrubbers for this application will cost between $6,900/ton and $13,800/ton SO_2 removed.

5.2.4.2 Semi Dry Scrubber

This control technology consists of spray-dry absorber, particulate control, and disposal of the reaction products. These are considered more-preferable for retrofits and for small to medium capacity boilers.

Energy Impacts

The semi-dry scrubber system will require additional energy for the pumps, blowers, and conveying equipment. This, in turn, will require additional coal combustion to provide the necessary energy. With additional combustion, additional $PM_{2.5}$ is emitted along with its precursors.

Environmental Impacts

The initial slurry mix will require water resources similar to the wet scrubber described above, although not at the same volumes. The byproducts of semi-dry control are less attractive for commercial use, and disposal in a landfill is expected. The waste product is dry rather than a slurry in this control option. Transporting the dry material to the landfill may lead to additional fugitive emissions of particulate.

Although the waste product is "dry," the system still relies on a slurry for the control process. The same concerns related to operating in a sub-Arctic environment remain for this control option. The benefit of SO_2 reductions must be balanced against using the water resources.

The Fort is required to maintain a constant state of readiness. Thus, the risks associated with operating a system that relies on a water-based solution in the sub-Arctic environment precludes its choice as a control device for the Fort.

Economic Impacts

Semi Dry systems have higher operational costs because of the more-expensive sorbents utilized. The systems are strongly affected by the flue gas temperature, humidity, SO_2 concentration, and the atomized slurry droplet size. The system would also likely need a fly ash control device prior to the absorber so that the efficiency of the operation can be maximized.

Cost estimates for spray dry scrubber systems were estimated by Andreas Poullikkas (Poullikkas, 2015) to have capital costs of $125 to $216/kW for capital costs and 0.59 cents to 0.78 cents/kWh for operating expenses. Converting to a $/ton removed cost suggests spray dry scrubbers for this application will cost between $5,200 and $6,200/ton SO_2 removed.

5.2.4.3 Dry Scrubber

AMERIAIR provided a formal proposal to provide a dry scrubber system for Fort Wainwright. The proposal is included in Appendix J. Rostisval Neveceral reports that this type of control has lower capital costs and has great potential for small boilers. Control efficiencies are estimated between 50% and 80% (Neveceral, 2015).

Energy Impacts

The Dry Scrubber system will require additional energy for the pumps and conveying equipment. This, in turn, will require additional coal combustion to provide the necessary energy. With additional combustion, additional $PM_{2.5}$ is emitted along with its precursors.

Environmental Impacts

Dry Scrubber produces a waste product that will need to be handled, transported, and landfilled. This additional waste stream is subject to dust generation during these activities.

Economic Impacts

The proposal from AMERIAIR indicates equipment costs of $2.8 million, excluding owner-supplied ducting and items as listed in the proposal. Utilizing EPA's cost template, the direct annual operating costs are estimated to be $2.5 million with a calculated cost of $4,500 to $6,000/ton SO_2 removed, for the 80% and 50% control efficiency cases, respectively. Direct capital costs are estimated to exceed $4.7 million.

Additional expenses associated with retrofitting 1950's era boilers present unique challenges, and the useful life of any additional control is estimated at 10 years because of DU and the Fort's operational agreements.

5.2.5 Step 5 – Select BACT for SO_2

Wet and Semi-Dry control technologies are not selected because of the concern of using a water-based technology, retrofitting to the boilers, space constraints, and costs.

The Dry Sorbent Injection system is not selected because of the economic impact.

Good combustion practices and Usibelli coal use were selected as BACT for SO_2 emissions. DU proposes a BACT limit of 0.2% sulfur, 12-month average gross as received coal limit. Additionally, DU proposes to reduce the allowable coal combustion from 336,000 ton/year to 300,000 ton/year. These two operational changes result in SO2 emission reductions of more than 700 tpy (which reduces SO2 emissions by more than 40%).

5.3 BACT FOR PARTICULATE MATTER LESS THAN 2.5 MICRONS ($PM_{2.5}$)

Solid material released during combustion of certain fuels such as coal consists of noncombustible ash-forming matter and unburned carbon particle. During combustion, these materials disperse throughout the flue gas as PM or accumulate inside the boiler as bottom ash or soot (ORNL, 2002). The baseline emissions for $PM_{2.5}$ have been revised from the Title V Permit Renewal Application. In that document, $PM_{2.5}$ was assumed to be equal to PM_{10}. This review considers $PM_{2.5}$ only. The Title V Permit Renewal Application used AP-42 emission factors from Section 1.1 and Tables 1.1.5 and 1.1.6 located in the EPA Air Emission Factors and Qualifications document (EPA, 1998).

Specifically, the referenced document, Table 1.1.5, identifies CPM emissions as 0.04 lb/MMBTU with a "C" emission factor rating. Table 1.1.6 identifies size distribution factors for dry bottom boilers burning sub bituminous coal. The table calculates emissions based on ash content of the fuel. The estimate in the Title V Renewal Permit Application applies the emission factor 0.02*ash content of 8.5% [lb/ton]. This calculation carries an "E" emission factor rating.

$PM_{2.5}$, using AP-42 sources of information, would reference Table 1.1.5 value of 0.04 lb/MMBTU and the information in Table 1.1.9 for stoker boilers of 0.032 lb/ton as the portion of the particle size distribution that is less than 2.5 microns. Table 1.1.9 assumes the baghouse controls 99.8% of total PM. AP-42 would suggest a total $PM_{2.5}$ emission factor of 0.072 lb/ton.

However, the AP-42 emission factors were published prior to the understanding of how stack testing methods needed to be refined in order not to bias the results with sulfur artifacts. A 2008 study by MATEC for the Mid Atlantic Regional Air Management Association, Inc. considered the data on which the AP-42 was crafted and used more-recent testing that applied the correct purging processes (MATEC, 2008). MATEC's report recommends 0.013 lb/MMBTU ± 0.002 lb/MMBTU (95% confidence interval) for the condensable portion of the exhaust.

Additionally, the facility has total PM emissions from MACT testing conducted in 2016 indicating filterable PM emissions that ranged for the 6 boilers between 0.001 lb/MMBTU and 0.01 lb/MMBTU.

Using these two emission factors suggests a $PM_{2.5}$ emission factor of 0.46 lb PM/ton coal. This emission factor is still conservative as the MACT testing was total filterable PM, and the facility does not have any size distribution data to more closely estimate the portion of filterable particulate less than 2.5 microns. Additionally, DU has included a 25% safety factor.

Using 300,000 tons coal/year and revised emissions from the six boilers indicates $PM_{2.5}$ emissions of approximately 72 tons $PM_{2.5}$/year.

5.3.1 Step 1 – Identify Available Control Strategies

ORNL identifies four general categories of equipment to reduce PM emissions post combustion: mechanical collectors, wet scrubbers, ESPs, and fabric filters.

- **Mechanical collectors**, also known as cyclones, are effective at recovering large particles through the high velocity vortex created within the device. This method is less effective for fine particles and is not considered a feasible approach for $PM_{2.5}$.
- **Wet scrubbers** remove particles through impacting individual particles with liquid droplets. A spray tower achieves PM removal by atomizing water and allowing the flue gas to flow through the resulting mist.
- **ESPs** remove PM suspended in a flue gas by electrically charging the particles and then collecting the particles as they accumulate on collector plate surfaces.
- **Fabric Filters** are very effective at separating particulates from flue gas and can successfully capture very fine particulate. These devices can remove more than 99.9% of PM from a flue gas stream.

The RBLC was queried for PM control for 100 to 250 MMBTU/hr coal-fired boilers. The database includes two such facilities with a total of two PM determinations (but only one $PM_{2.5}$ determination). The single $PM_{2.5}$ determination calls for Good Design and Proper Operation as a case-by-case determination. The PM determination identifies a cyclone and scrubber as BACT and established a limit of 0.01 lb/MMBTU, 3-hr average.

The RBLC for larger EGUs was also consulted. It shows the following BACT determinations for PM_{10}, $PM_{2.5}$, and PM:

- ESPs and Wet FGD – 0.03 lb/MMBTU
- ESPs and Wet FGD – 0.0418 lb/MMBTU, 3-hr average

The CHPP Boilers are already being controlled using FSBs.

5.3.2 Step 2 – Identify Technically Feasible Control Technologies

Table 5.3, CHPP RBLC – PM, lists the PM control technology. Mechanical collectors are not considered technically feasible for collecting $PM_{2.5}$ material, as the particles are so small they can escape the high velocity vortex of a cyclone.

Wet scrubbers and ESPs are not technically feasible because of the location in Alaska. Maintaining a wet scrubber system during the numerous subzero periods makes this option infeasible. Additionally, these approaches are no more effective than the fabric filters that are in place.

Wet FGD, discussed in greater detail as part of the SO_2 demonstration, is likewise problematic and infeasible due to the significant cold temperature of the region.

5.3.3 Step 3 – Rank the Technically Feasible Control Technologies

The technically-feasible $PM_{2.5}$ control technologies for the boilers are ranked by control effectiveness and listed below:

Control Technology	Reduction (%)
FSB (base case)	99.9+%
Electrostatic Precipitation	97.7[1] 99.6% [2]

[1]EPA, 2003a
[2]ORNL, 2002

5.3.4 Step 4 – Evaluate the Most Effective Control Technologies

Because the most-controlling option is currently in use at CHPP, no additional review of BACT for $PM_{2.5}$ is required.

5.3.5 Step 5 – Selected $PM_{2.5}$ BACT Determination

BACT for $PM_{2.5}$ control is FSB control with an emission limit of 0.05 gr/dscf (EPA, 2017), 3-hr average.

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6.0 EMERGENCY ENGINES, FIRE PUMPS, AND GENERATORS

Between the two facilities, there are a total of 49 engines, generators, and fire pumps. All are intended for emergency operations only and all are diesel fired.

All diesel fuel-fired compression ignition engines operate with the same basic process. Air and fuel are mixed in combustible proportions within the space between the head of a piston and its cylinder. The mixture is ignited and the resulting products of combustion move the piston down the cylinder. This movement is converted to rotary motion at the crankshaft, the piston returns to its starting position releasing exhaust gases on the return path. The products of combustion which are exhausted are primarily NO_x, CO, and hydrocarbons. Low levels of PM, SO_2, may also be emitted.

6.1 NO_X EMISSION CONTROL

NO_x formation in compression ignition engines is primarily a function of pressure and temperature during combustion (thermal NO_x) and only minimally as a result of fuel-bound nitrogen. Thus, controlling the combustion process is the most expedient pathway to minimizing NO_x from these types of engines.

6.1.1 Step 1 – Identify All Available Control Technologies

The RBLC database was queried in April 2017 for previous determinations related to BACT for emergency engines, pumps, and generators. The query was limited to diesel-fired engines and determinations completed since January 1, 2012. A total of 78 sources were identified in the database for consideration, see Table 6.1 Emergency Engines, Fire Pumps, and Generators - NO_x. In addition, research conducted on various control technologies was also completed.

Regarding NO_x control, the research reveals the following control approaches:

- Good Combustion Practices, Good Combustion Design – Identified 31 times in RBCL database
- Certified Engine Purchase, Comply with 40 CFR 60 Subpart IIII, and/or Comply with 40 CFR 63 Subpart ZZZZ – Identified 26 times in RBCL database
- Ultra Low Sulfur Diesel (ULSD) – Identified 12 times in RBCL database
- Limited Hours of Operation – Identified 10 times in RBCL database
- Limited Hours of Non-Emergency Operation – Identified 2 times in RBCL database
- LNB and flue gas recirculation (FGR) – The underlying Indiana permit 109-32471-00004 limits the 500 hp diesel-fired emergency fire pump to 3 gal/hp-hr NO_x+NMHC through the use of combustion design controls and usage limitations.

Other NO_x emission controls that have been identified for limited use (i.e., emergency diesel fuel fired engines) include the following:

- Exhaust gas recirculation for NO_x reduction

- Lean NO_x catalyst technology
- NO_x adsorber technology
- Oxidation catalysts
- SCR
- SNCR

SCR is discussed in greater detail under the CHPP Boiler NO_x BACT section. SCR is available for engine applications and is employed with some engine systems to achieve Tier 4 standards. SCR uses a catalyst along with urea or ammonia reductants to convert NO_x in the exhaust to water and nitrogen. The catalyst lowers the reaction temperature required for the conversion to take place to temperatures between 260 C and 540 C. Well-designed SCR systems can reduce NO_x by 95% (California Environmental Protection Agency [CalEPA], 2010).

To be successful, SCR requires operating temperatures between 260°C and 540°C. For large base-load application, these temperatures are achievable for steady state operation. However, the units at the Garrison are small and operate infrequently – primarily only for testing and maintenance. With the exception of the Blackstart Generator and the Fire Station generators, the engines are tested monthly and operate approximately 30 minutes. The Backup Generator in 2016 ran an average of 2 hours per month. The fire station generators are started weekly, and in 2016 the generator ran an average of 1 hour a month or less than 20 minutes per start. The engines are not fully-loaded and temperatures do not reach the threshold at which an SCR control system would be initiated. In addition, the urea/ammonia handling and maintenance creates its own technical challenges and limitations. Urea crystallization in the lines to the SCR system is more likely in emergency engines becaue of periodic and low usage.

For the Garrison's operations, SCR control on emergency engines is technically infeasible because of the low load on the engines; the short time period in which the engines operate for testing and maintenance (during which time the temperatures required for SCR to be initiated are not achieved); and because the urea systems will be subject to significant crystallization risk. The addition of SCR to these engines will provide little, if any, NO_x reduction, as the vast majority of the time these engines operate for testing and maintenance purposes only.

6.1.2 Step 2 – Determine Technical Feasibility of Available Options

Lean NO_x catalyst and NO_x adsorber technologies have not been demonstrated successfully on compression ignition engines. Likewise, SCR and SNCR technologies are not technically feasible for these limited-operation emergency applications. Thus, all options are available for the Fort Wainwright and DU emergency engines, fire pumps, and generators, with the exception of SCR, Lean NO_x catalyst, NO_x adsorber technologies, and SNCR.

6.1.3 Step 3 – Rank Control Technologies by Control Effectiveness

Controls identified in the RBLC are arranged below in order of most-controlling to less-controlling options below:

Control Technology	NOx Limits Noted in Database	Notes
Comply with 40 CFR 60 Subpart IIII	Varies as function of horsepower and date of engine manufacture	
Good Combustion Practices – BACT referenced	In several cases, this control technology is not associated with an emission limit. In the cases where a limit is present, the values range from 2.85 g/hp-hr to 9.5 g/hp-hr.	Most of the emission limits listed under Good Combustion Practices are actually associated with 40 CFR 60 Subpart IIII limits associated with the engine. Thus, many of these "good combustion practices" are identical to "Comply with 40 CFR 60 Subpart IIII"
Good Combustion – LAER referenced	Ranges from 2.1 g/hp-hr to 7.2 g/hp-hr	
Limited Hrs of Operation	Limits vary from 100 hrs to 500 hrs per year non-emergency use	

6.1.4 Step 4 – Evaluate Most Effective Controls and Document Results

A BACT review is normally associated with new construction or modification activities. In this case, the BACT review is precipitated by a change in the attainment status of the region. Therefore, there is no modification occurring to the engines because Fort Wainwright is assessing each engine for Best Available Control.

No additional evaluation is required because the most controlling technically feasible options are to be selected.

6.1.5 Step 5 – Select BACT

Table 6.2 presents the engines, generators, and fire pumps located within the privatized unit and within the Garrison's permits. Engines are listed from largest to smallest and are identified by location, make/model, and certification status. Consistent with the RBLC dataset, the Garrison and DU are proposing a combination of BACT approaches for these engines.

For engines manufactured after the applicability dates of 40 CFR 60 Subpart IIII, BACT is selected as Compliance with 40 CFR Part 60 Subpart IIII. For older engines, compliance with 40 CFR Part 63 Subpart ZZZZ is selected as BACT.

For engines, currently subject to ORL, BACT is selected to specify the same ORL. Namely, for engines 11, 12, and 13 at the Garrison, BACT will be limiting the operation of these three EUs to less than 600 hrs in total per 12-month period. EU 8 at DU may convert from emergency classification to non-emergency classification under Subpart ZZZZ, but will still be limited to 500 hr/year for all operations.

For all other engines, pumps, and generators BACT is selected as Good Combustion Practices.

Emission estimates for the majority of the engines located at DU and the FWA are based on AP-42 emission factors. FWA and DU are not proposing specific NO_x limitations as a function of hp-hrs within this BACT analysis because the magnitude of emissions is limited and the best approach to minimizing emissions is to ensure good combustion practices through maintenance and operating procedures.

6.2 SO_2 EMISSION CONTROL

SO_2 emissions may be emitted from the diesel fuel-fired compression ignition engines. SO_2 emissions are a function of the sulfur content of the fuel.

6.2.1 Step 1 – Identify All Available Control Technologies

The RBLC database was queried in April 2017 for previous determinations related to BACT for emergency engines, pumps, and generators. The query was limited to diesel-fired engines and determinations completed since January 1, 2012. A total of 44 sources were identified in the database for consideration, see Table 6.2 Emergency Engines, Fire Pumps, and Generators. In addition, research conducted on various control technologies was also completed.

Regarding SO_2 control, the research reveals the following control approaches which are available at DU:

- Use of ULSD – Identified 21 in RBLC database
- Certified Engine Purchase, comply with 40 CFR 60 Subpart IIII – Identified 8 times in data base
- Limited Hours of Operation – Identified 8 times in data base
- Good Combustion Practices, Good Combustion Design – Identified 7 times in data base
- Limited Fuel Usage – Identified 4 times in data base

6.2.2 Step 2 – Determine Technical Feasibility of Available Options

All options identified within the RBLC data set are available to be employed at the DU and Garrison facilities with the exception that the certified engine status option is available only to those engines manufactured and installed after the effective date within 40 CFR 60 Subpart IIII.

40 CFR 60 Subpart IIII does not limit SO_2 emissions *per se*. It does, however, specify compliance with 40 CFR 80.510(b), which limits engines subject to 40 CFR 60 Subpart IIII to ultra-low sulfur diesel. The Fort Wainwright location is not considered “remote” and therefore, the ULSD requirement is already in place for the engines subject to Subpart IIII.

6.2.3 Step 3 – Rank Control Technologies by Control Effectiveness

Controls identified in the RBLC are arranged below in order of most-controlling to less-controlling options.

Control Technology	Notes
Use of ULSD	See below
Certified Engine, Comply with 40 CFR 60 Subpart IIII	Requires ULSD for engines subject to 40 CFR 60 Subpart IIII unless located in remote areas of Alaska. This location is not considered “remote.”
Limited Hrs of Operation	Ranges from 52 to 500 hrs/year for testing (non-emergency) operations.
Good Combustion Practices, Good Combustion Design	Follow manufacturer recommendations; maintain records of maintenance; opacity limit during start up, shutdown, and malfunction of 20%, 6-minute average.
Limited Fuel Usage	One facility limited the gallons of diesel burned in a 12-month period (IN-0234).

6.2.4 Step 4 – Evaluate Most Effective Controls and Document Results

A BACT review is normally associated with new construction or modification activities. In this case, the BACT review is precipitated by a change in the attainment status of the region. Thus, although there is no modification occurring to the engines, Fort Wainwright is assessing each engine for Best Available Control.

Because the most controlling technically feasible options are to be selected, no additional evaluation is required.

6.2.5 Step 5 – Select BACT

For all diesel-fired engines, generators, and pumps located at the DU and FWA facilities, BACT is selected as the following:

- Use of ULSD fuel

Compliance with this requirement will be met by maintaining records of fuel sulfur content. The Garrison and DU are not proposing specific SO_2 limitations as a function of hp-hrs within this BACT analysis because the magnitude of emissions is limited and the best approach to minimizing emissions is to use ULSD. Both facilities will maintain fuel certifications annually from the supplier noting the sulfur content of the fuel.

6.3 $PM_{2.5}$ EMISSION CONTROL

Solid material released during combustion of certain fuels such as diesel consists of noncombustible ash-forming matter and unburned carbon particle. During combustion, these materials disperse throughout the exhaust as PM.

6.3.1 Step 1 – Identify All Available Control Technologies

The RBLC database was queried in April 2017 for previous determinations related to PM, PM less than 10 microns (PM_{10}), $PM_{2.5}$, and Filterable PM BACT for emergency engines, pumps, and generators. The query was limited to diesel-fired engines and determinations completed since January 1, 2012. A total of 47 sources were identified in the database for consideration, see Table 6.4 Emergency Engines, Fire Pumps, and Generators – PM. In addition, research conducted on various control technologies was also completed.

Regarding PM control, the RBLC database reveals the following control approaches:

- Good Combustion Practices, Good Combustion Design – Identified 35 times in RBCL database
- Use of ULSD – Identified 21 times in RBCL database
- Certified Engine, comply with 40 CFR 60 Subpart IIII and/or 40 CFR 63 Subpart ZZZZ – Identified 15 times in RBCL database
- Limited Hours of Operation – Identified 12 times in RBCL database

In addition to the RBLC approaches selected, there are other potential add on control systems available to reduce PM emissions from diesel-fired engines.

6.3.1.1 Selective Catalytic Reduction and Diesel Particulate Filter

This combination approach can reportedly reduce $PM_{2.5}$ by 85% (EPA, Engine data). SCR has been introduced and described previously in this Report. Diesel Particulate Filters (DPFs) are detailed below.

6.3.1.2 Selective Catalytic Reduction and Diesel Oxidation Catalyst

This combination approach can reportedly reduce $PM_{2.5}$ by 25% (EPA, Engine data). SCR has been introduced and described previously in this Report. Diesel Oxidation Catalysts (DOCs) are detailed below.

6.3.1.3 Diesel Particulate Filters

These filters consist of porous substrate that permits gases in the engine exhaust to pass through but traps the diesel PM (CalEPA, 2010). The particulate is periodically burned off through regeneration. Emission reductions are a function of engine type, fuel sulfur content, and engine duty cycle. Reductions of up to 50% $PM_{2.5}$ (EPA, Engine data) and 85% PM (ARB, B-1) have been reported. Oklahoma Department of Environmental Quality (ODEQ) estimates DPF systems are 60 to 90% effective at removing $PM_{2.5}$ (ODEQ, 2017).

DPF systems are considered either “active” or “passive.” Active systems use electrical, fuel, or fuel injection to increase exhaust gas temperature. These systems have a broader range of applications and a lower probability of plugged systems. Passive DPFs employ a catalytic material applied to the substrate. Similar to SCR systems, the catalyst lowers the temperature at which the PM is oxidized to temperatures periodically reached during the engine’s operation.

Success of the passive DPF is determined based on average exhaust temperature at the filter’s inlet and the rate of PM generated by the engine. In 2011, California Air Resources Board reported more than 300 emergency standby engines equipped with DPFs were operating in California. Its research indicates that passive DPFs require regeneration every 10 to 30 cold start/idle sessions. Regeneration requires sustained temperature of the exhaust between 300°FC and 465°C for 30 minutes to 2 hours. DPFs will also reduce hydrocarbons and CO. ULSD is a requirement for these systems.

6.3.1.4 Diesel Oxidation Catalyst

This control technology can reportedly reduce $PM_{2.5}$ emissions by 30% (ODEQ, 2017) 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 (ODEQ, 2017). The ODEQ estimates the cost of DOC between $1,000 and $2,000. DOCs will additionally reduce hydrocarbons (50% effective) and CO (40% effective).

6.3.2 Step 2 – Determine Technical Feasibility of Available Options

All options described above are technically feasible on the engines at Fort Wainwright with the exception of SCR. For sources of this size, SCR is not a technically feasible approach.

6.3.3 Step 3 – Rank Control Technologies by Control Effectiveness

Controls identified in the RBLC are arranged below in order of most-controlling to less-controlling options.

Control Technology	Notes
DPF	60% to 90% control of $PM_{2.5}$ possible
DOC	30% control of $PM_{2.5}$ possible
Use of ULSD	
Certified Engine, Comply with 40 CFR 60 Subpart IIII	Requires ULSD for engines subject to 40 CFR 60 Subpart IIII unless located in remote areas of Alaska. This location is not considered "remote."
Limited Hrs of Operation	Ranges from 52 to 500 hrs/year for testing (non-emergency) operations.
Good Combustion Practices, Good Combustion Design	Follow manufacturer recommendations; maintain records of maintenance.

6.3.4 Step 4 – Evaluate Most Effective Controls and Document Results

A BACT review is normally associated with new construction or modification activities. In this case, the BACT review is precipitated by a change in the attainment status of the region. Therefore, there is no modification occurring to the engines because Fort Wainwright is assessing each engine for Best Available Control.

DPF – California Air Resources Control Board determined the cost of retrofitting gen-sets with an aftermarket DPF to be $38 per hp (CalEPA, 2010). Its research assessed emission reductions from various sizes of engines and at several load points to simulate the operations of emergency engines. California's research concluded that:

> *"It is not cost effective to routinely apply DPF or SCR after treatment technologies on emergency standby engines. The costs of SCR and DPF after-treatment technology are very high given the low number of hours that a typical emergency standby engine operates…"*

Using the $38/hp cost, and assuming an 85% removal of $PM_{2.5}$ as a result of the control yields, a cost per ton ranging between $81,000/ton and more than $3,600,000/ton $PM_{2.5}$ removed. ODEQ provides general costing and efficiency information as well. Using its information indicates a range between $26,518/ton and more than $7,000,000/ton. The DPF will also reduce hydrocarbons and CO; however, because there are no RBLC determinations for emergency engines related to DPFs, the benefit of co-reductions has not impacted the economic viability of the technology for limited use emergency engines.

DOCs are primarily designed to reduce CO and hydrocarbons. Using information published by ODEQ (ODEQ, 2017), the cost effectiveness of the technology on the emergency engines located at the DU facility at Fort Wainwright would range between $20,000 and $5,400,000 per ton $PM_{2.5}$

removed. Similar to DPFs, the benefit of co-reduction has not impacted the economic viability of the technology for limited use emergency engines.

6.3.5 Step 5 – PROPOSE BACT

Referring once again to Tables 3.1 and 3.2, the tables presents the engines, generators, and fire pumps located within the privatized unit and within the Garrison's permits. Engines are listed from largest to smallest and are identified by location, make/model, and certification status. Consistent with the RBLC dataset, the Garrison and DU are proposing a combination of BACT approaches for these engines.

For all engines, fuel will be limited to ULSD.

For engines manufactured after the applicability dates of 40 CFR Part 60 Subpart IIII, BACT is selected as Compliance with 40 CFR Part 60 Subpart IIII.

7.0 SMALL BOILERS

The FWA facility includes 29 boilers – 27 distillate-fuel fired and 2 waste-oil fired. As detailed in the BACT Work Plan, see Appendix A, only the four largest distillate fuel fired boilers are considered in the BACT analysis. The waste oil boilers represent less than 1 tpy potential NO_x, and less than 7 tpy potential SO_2. The remaining 23 distillate-fuel fired report potential NO_x and PM less than 1 tpy and SO_2 emissions less than 1.5 tpy in total. The largest boilers are EUs 8, 9, and 10 and are each 19 MMBTU/hr. These three boilers are limited to a total of 600 hours annually. Because all the boilers are less than 19 MMBTU/hr, the BACT determination will conservatively consider these as representative of all others.

7.1 NO_X EMISSION CONTROL

As stated in Section 5.1, NO_x is primarily formed in combustion processes in two ways:

1. The combination of elemental nitrogen with oxygen in the combustion air within the high temperature environment of the combustor (thermal NO_x).
2. The oxidation of nitrogen contained in the fuel (fuel NO_x).

Control of NO_x emissions from combustion is generally aimed at either the prevention of NO_x formation or the capture and oxidation of post-combustion NO_x. Because the rate of formation of thermal NO_x is a function of residence time and free oxygen, and is exponential with peak flame temperature, “front-end” control techniques are aimed at controlling one or more of these variables.

7.1.1 Step 1 – Identify All Available Control Technologies

The RBLC database was queried in April 2017 for previous determinations related to BACT for diesel and distillate fired boilers less than 100 MMBTU/hr in size. The query was limited to diesel-fired engines and determinations completed since January 1, 2007. A total of nine sources were identified in the database for consideration. See Table 7.1- Small Boilers RBLC – NO_x.

Regarding NO_x control, the research reveals the following control approaches:

- LNB and FGR – Identified 1 time in RBLC database, represents LAER
- LNB – Identified 3 times in RBLC database
- Good Combustion Practices – Identified 3 times in RBCL database
- Use of ULSD – Identified 1 time in RBLC database
- Limited Hours of Operation – Identified 1 time in RBCL database
- Unspecified – Identified 1 time in RBLC database

7.1.2 Step 2 – Determine Technical Feasibility of Potential Options

Each of these options are believed to be technically feasible.

7.1.3 Step 3 – Rank Control Technologies by Control Effectiveness

Controls identified in the RBLC are below in order of most-controlling to less-controlling options.

Control Technology	NO_x Limits Noted in Database	Notes
LNB and FGR	0.07 lb/MMBTU	1.5 lb/hr for 20.4 MMBTU boiler. This limit required by LAER and SIP in Ohio.
LNB	Range between 0.02 lb/MMBTU and 0.14 lb/MMBTU	
Good Combustion Practices	None	RBLC includes limited annual emissions.
Use of ULSD	None	None
Limited Hrs of Operation	None	None
Unspecified	None	None
Base Case	0.14 lb/MMBTU	Based on AP-42 emission factors.

7.1.4 Step 4 – Evaluate Most Effective Controls and Document Results

A BACT review is normally associated with new construction or modification activities. In this case, the BACT review is precipitated by a change in the attainment status of the region. Thus, although there is no modification occurring to the engines, Fort Wainwright is assessing each engine for BACT.

In 2009, Andrew Bodnarik, New Hampshire Department of Environmental Services, presented to the Ozone Transport Commission Committee regarding industrial, commercial, and institutional boiler NO_x and SO_2 Control Cost Estimates (Bodnarik, 2009). Mr. Bodnarik's talk included information related to the costs of various technologies as a function of unit size and as a function of the entity making the analysis. He assumed NO_x emission from distillate fired units controlled via LNB would be reduced from 0.2 lb/MMBTU to 0.10 lb/MMBTU. Bodnarik's analysis uses 2008 data; Fort Wainwright does not expect significantly different assumptions or conclusions as a result of the passage of time. Indeed, Mr. J. Edward Cichanowicz reported to the Utility Air Regulatory Group in January 2010 that air pollution control equipment costs have increased more quickly than inflation (Cichanowicz, 2010), potentially resulting in an under-estimation of costs. For the LNB control, his data suggest NO_x removal costs for 50 MMBTU/hr units to be between $10,900/ton and $43,600/ton, assuming a 66% capacity factor. Extrapolating this data to less than 3% capacity factor and to a 19 MMBTU unit results in costs significantly higher and clearly economical infeasibility.

7.1.5 Step 5 – Propose BACT

Each boiler at the Fort Wainwright facility is limited to testing, maintenance, and emergency use only with the exception of the waste fuel boilers. Because LNBs are prohibitively expensive, FWA proposes Good Combustion Practices as BACT for these EUs. The ORL related to the hours of operation of units 8, 9, and 10 are already incorporated into the facility's permit and are federally enforceable as such.

7.2 SO_2 EMISSION CONTROL

SO_2 emissions may be emitted from the diesel fuel-fired boilers. SO_2 emissions are a function of the sulfur content of the fuel.

7.2.1 Step 1 – Identify All Available Control Technologies

The RBLC database query identifies limiting the sulfur in the fuel as BACT for five of the six determinations (the remaining entry did not specify a control method). Although there are post combustion strategies that can be implemented on boilers, the analysis for the main CHPP boilers earlier in this document illustrate that even for units greater than 200 MMBTU, the economics preclude these additional control options. See Table 7.2 Small Boilers RBLC – SO_2.

7.2.2 Step 2 – Determine Technical Feasibility of Available Options

Good combustion practices and limiting the amount of sulfur in the fuel are each technically feasible.

7.2.3 Steps 3 Through 5 – Rank Control Technologies by Control Effectiveness Through Propose BACT

FWA proposes Good Combustion Practices and use of low sulfur fuel in the distillate boilers at the Garrison. For the Waste Oil Boilers, the Garrison proposes Good Combustion Practices. FWA EUs 8, 9, and 10 are already limited to a total of 600 hours per year.

7.3 $PM_{2.5}$ EMISSION CONTROL

Solid material released during combustion of certain fuels such as diesel consists of noncombustible ash-forming matter and unburned carbon particle. During combustion, these materials disperse throughout the flue gas as PM.

7.3.1 Step 1 – Identify All Available Control Technologies

The RBLC database was queried in April 2017 for previous determinations related to PM, PM_{10}, $PM_{2.5}$, and Filterable PM BACT for small boilers. The query was limited to boilers and determinations completed since January 1, 2007. A total of 12 sources identified in the database for consideration provided BACT information related to PM emissions only. See Table 7.3 Small Boiler RBLC – PM.

Regarding PM control, the RBLC database reveals the following control approaches:

- Good Combustion Practices, Good Combustion Design – Identified 5 times in RBCL database
- No method specified – Identified 7 times in RBCL database

7.3.2 Steps 2 Through 5 – Determine Technical Feasibility of Available Options Through BACT Proposals

Consistent with the RBLC dataset, the Garrison proposes specifying Good Combustion Control for all boilers at the Garrison.

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8.0 MATERIAL HANDLING

Only $PM_{2.5}$ will be considered in the BACT Analysis for the material handling equipment. The sources considered under the Analysis include the Coal Handling sources (7a, 7b, and 7c, the Ash Handling sources (51a and 51B), and the coal pile itself. ADEC has previously identified the following limits for these sources:

Source	Description	Emission Factor	Hrs/Year Operation	$PM_{2.5}$ (tpy)
7a	South Coal Handling Dust Collector	0.0025 gr/dscf	2195	0.04
7b	South Underbunker Dust Collector	0.020 gr/dscf	100	<0.00 tpy
7c	North Coal Handling Dust Collector	0.05 gr/dscf	45	<0.00 tpy
51a	Fly Ash Dust Collector	0.02 gr/dscf	8760	0.35
51b	Bottom Ash Dust Collector	0.02 gr/dscf	8760	0.35
52	Coal Pile	AP-42 calculation		0.48

8.1.1 Step 1 – Identify All Available Control Technologies

The RBLC database was queried in April 2017 for previous determinations related to PM, PM_{10}, $PM_{2.5}$, and filterable PM for material handling sources. These include conveyors, haul roads, storage piles, and transfer points. The query was limited to determinations completed since January 1, 2012. A total of 17 sources were identified in the database for consideration, see Table 8.1 Material Handling RBLC – PM. In addition, research conducted on various control technologies was completed.

Regarding PM control, the RBLC database reveals the following control approaches:

Control	RBLC Emission Limits
Baghouses/Fabric Filters	0.0015 gr/dscf to 0.005 gr/dscf, averaging period 3 hrs for Total PM, Total PM_{10}, and Total $PM_{2.5}$
Wet Dust Extraction	An option, in lieu of Baghouse/Fabric Filter
Wet/Chemical Suppression	90% control
Prompt Clean Up of Spills	

Texas Council for Environmental Quality (TCEQ) maintains BACT guidelines for various emission sources, including bulk material handling. The state of Texas has established minimum acceptable control for material handling processes at 70% control. For coal handling activities, 70% control is required at storage piles, load-in, and roadways – usually accomplished using water sprays. Transfer points require 85% control through the use of foam and/or surfactants. Conveying normally requires enclosures and/or chemical sprays to achieve 90% reduction. Finally, loading coal requires 95% reduction of PM emissions through the use of chemical wetting and enclosures in addition to fabric filters on silos (TCEQ, 2013).

In addition to the controls identified within the RBLC and TCEQ information, EPA shares control information within the emission estimating tools of AP-42. The following control options are noted:

- Total or partial enclosed buildings, conveyors, silos, or surge bins – without dust collection systems.
- Total enclosure with dust collection systems utilizing various controls (fabric filter, dry ESPs, wet ESPs, venturi scrubbers, and cyclones).

8.1.2 Step 2 – Determine Technical Feasibility of Available Options

Enclosures are not technically feasible for coal pile storage.

Wetting agents and watering are not technically feasible year-round in this environment. Wetting roads and piles are not technically feasible, nor safe, when the temperatures are below freezing.

8.1.3 Step 3 – Rank Control Technologies by Control Effectiveness

For the EUs other than the coal pile, controls identified in the RBLC are arranged below in order of most-controlling to less-controlling options.

Control Technology	Notes
Partial or Total Enclosures	50% to 99+%
Baghouses/Fabric Filters	Up to 99+%
Venturi Scrubbers	70% to 99%+
Cyclones	<90%, especially for fine PM

8.1.4 Step 4 – Evaluate Most Effective Controls and Document Results

Enclosures are utilized extensively on the conveying and transfer operations. These enclosures are already vented to dust collectors to reduce emissions of $PM_{2.5}$ to the environment.

The baghouses and fabric filters are capable of operating in a variety of conditions and are reliable with regard to emission control and operations. Thus, a venturi scrubber provides no performance or cost benefit to the coal and ash handling activities at Fort Wainwright. Venturi scrubbers have the disadvantage of requiring water and generating a wet waste.

Enclosures combined with dust collection systems represent the BACT for the material handling EUs 7a, 7b, 7c, 51a, and 51b.

8.1.5 Step 5 – Propose BACT

Based on the evaluation of the most effective controls, the following table outlines the selected BACT.

EU Id	Description	Current Control	Current Emission Factor	Selected 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	None Selected – this source serves as backup to 7a and operates less than 200 hrs each year.
52	Emergency Coal Storage Pile and Operations	See the table below for the measures already employed as part of the facility's Dust Control Plan		Follow the facility Dust Control Plan
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.

Coal Stockpile

As identified in the Dust Control Plan, see Appendix K, the following Best Available Control Measures (BACM) are employed at the coal pile. These techniques additionally represent Best Available Control Technologies for this EU.

Measure	When Employed
Chemical Stabilizers	Hygroscopic chemicals, which attract moisture to the surface. This method is effective in areas not subject to daily disturbance.
Wind Fencing	Use of 3 to 5 foot barriers with less than 50% porosity. The barriers are located adjacent to roadways, which could be impacted by windblown material leaving the storage pile.
Cover Haul Vehicles	When transporting coal from the coal pile to the CHPP, the truck's load should be covered or there should be 1 foot freeboard.
Watering	Apply in sufficient quantity to keep surface moist. Application frequency will depend on weather conditions.
Wind Awareness	Cease operations during high wind events if possible. If not possible, use watering. Load and unload on the downwind side of the pile.

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9.0 CONCLUSION

Based on the BACT Analysis, the following BACT devices or operational limits should be considered as meeting the EPA methodology for choosing BACT.

Summary Table of BACT

Pollutant	Proposed BACT Emission Limitation	BACT Device(s) or Operational Limitation(s)
Coal Fired Boilers - 230 MMBTU/hr, DU-1 through DU-6 ***Coal combustion limited to 300,000 ton/year, 12 month rolling totals***		
• NO_x • SO_2 • $PM_{2.5}$	• 6.6 lb/ton coal combusted • 0.2% sulfur by weight in fuel, 12-month weighted average • 0.46 lb $PM_{2.5}$/ton coal combusted	• Good Combustion Practices • Good Combustion Practices • Full Stream Baghouse
Emergency Engines, Generators, and Fire Pumps		
• NO_x • SO_2 • $PM_{2.5}$	• Operations of certified engines and good combustion practices • Good combustion practices and combustion of ULSD • Good combustion practices and combustion of ULSD	
Fuel Oil Boilers		
• NO_x • SO_2 • $PM_{2.5}$	• Good combustion practices • Good combustion practices and combustion of ULSD • Good combustion practices	
Material Handling Sources (Coal Prep and Ash Handling)		
• $PM_{2.5}$ • $PM_{2.5}$	• Enclosed emission points and follow manufacturer recommendations for operations and maintenance	

By implementing the BACT devices and operational limits presented above, the Fort Wainwright Installation, a combination of EUs owned and operated by DU and FWA, should meet the following reductions presented below.

Proposed BACT Emission Reductions

Source	NO_x (tpy)		SO_2 (tpy)		$PM_{2.5}$ (tpy)	
	Baseline	**Selected**	**Baseline**	**Selected**	**Baseline**	**Selected**
Doyon Utilities, LLC						
DU-1 through DU-6	1,478	990	1,764	1,050	131	69
Emergency Engines, Generators, and Pumps	54	32	2.8	0.22	2.6	1.7
Material Handling Equipment	0	0.00	0.00	0.00	4	5
Facility Total	1,533	1,022	1,767	1,050	143	74
Fort Wainwright Garrison						
Fuel Oil Boilers	2.5	2.5	7.3	7.5	0.1	0.1
Emergency Engines, Generators, and Pumps	25.4	25.4	4.9	4.9	1.2	1.2
Waste Oil Boiler	0.42	0.42	6.44	6.44	0.34	<0.01
Facility Total	28.19	28.19	9	19	1.33	1.33
TOTAL	1,561	1,051	1,786	1,069	142	73
Reduction (tpy)	510		717		69	
% Reduction	33%		40%		49%	

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TABLES

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Table 3.1
Doyon Utilities Significant Privatized Emission Units for BACT Analysis

Emission Unit				Installation Date	Fuel Type	Rating	
ID	Name	Description	Bldg. No.				
Coal Fired Boilers							
1	Coal-Fired Boiler 3	Central Heat and Power Plant (CHPP)	CHPP	1953	Coal	230	MMBtu/hr
2	Coal-Fired Boiler 4	CHPP	CHPP	1953	Coal	230	MMBtu/hr
3	Coal-Fired Boiler 5	CHPP	CHPP	1953	Coal	230	MMBtu/hr
4	Coal-Fired Boiler 6	CHPP	CHPP	1953	Coal	230	MMBtu/hr
5	Coal-Fired Boiler 7	CHPP	CHPP	1953	Coal	230	MMBtu/hr
6	Coal-Fired Boiler 8	CHPP	CHPP	1953	Coal	230	MMBtu/hr
Material Handling - Coal							
7a	South Coal Handling Dust Collector (DC-01)	Airlanco 169-AST-8	CHPP	2001	N/A	13,150	acfm
7b	South Underbunker Dust Collector (DC-02)	Airlanco 16-AST	CHPP	2005	N/A	884	acfm
7c	North Coal Handling Dust Collector (NDC-1)	Dustex C67-10-547	CHPP	2004	N/A	9,250	acfm
Distillate Fueled Emergency and Black Start Generators							
8	Black Start Generator Engine	Caterpillar 3516C	CHPP	2009	Distillate	2,937	hp
9	Generator Engine	Detroit 6V92	1032	1988	Distillate	353	hp
10	Generator Engine	Caterpillar C15	1060	2010	Distillate	762	hp
11	Generator Engine	Caterpillar C15	1060	2010	Distillate	762	hp
12	Generator Engine	Cummins B3.3	1193	2002	Distillate	82	hp
13	Generator Engine	Caterpillar 3406C TA	1555	2008	Distillate	587	hp
14	Generator Engine	Cummins QSL-G2 NR3	1563	2008	Distillate	320	hp
15	Generator Engine	Detroit R1237M36	2117	2005	Distillate	1,059	hp
16	Generator Engine	John Deere 6068TF250	2117	2005	Distillate	212	hp
17	Generator Engine	John Deere 6068TF250	2088	2007	Distillate	176	hp
18	Generator Engine	John Deere 6068HF150	2296	2005	Distillate	212	hp
19	Generator Engine	John Deere 4045TF270	3004	2007	Distillate	71	hp
20	Generator Engine	John Deere 4239D	3028	1976	Distillate	35	hp
21	Generator Engine	Perkins 2046/1800	3407	2001	Distillate	95	hp
22	Generator Engine	Cummins	3565	1989	Distillate	35	hp
23	Generator Engine	John Deere 6068HF150	3587	2003	Distillate	155	hp
24	Generator Engine	Cummins L634D-I/10386E	3703	1993	Distillate	50	hp
25	Generator Engine	Caterpillar C1.5	5108	2011	Distillate	18	hp
26	Generator Engine	Cummins 4B3.9-G2	1620	2003	Distillate	68	hp
27	Generator Engine	Caterpillar C6.6	1054	2010	Distillate	274	hp
28	Generator Engine	Caterpillar C6.6	4390	2010	Distillate	274	hp

Table 3.1
Doyon Utilities Significant Privatized Emission Units for BACT Analysis (continued)

Emission Unit				Installation	Fuel	Rating	
ID	**Name**	**Description**	**Bldg. No.**	**Date**	**Type**		
Distillate Fueled Emergency and Black Start Generators (continued)							
29	Lift Pump Engine	Detroit Diesel 5116493	1056	1988	Distillate	75	hp
30	Lift Pump Engine	Detroit Diesel 10245100	3403	1952	Distillate	75	hp
31	Lift Pump Engine	Detroit Diesel 10245100	3724	1952	Distillate	75	hp
32	Lift Pump Engine	Perkins	4162	1955	Distillate	75	hp
34	Well Pump Engine	Detroit Diesel 10447000	3405	1995	Distillate	220	hp
35	Well Pump Engine	John Deere 4045DF120	4023	2009	Distillate	85	hp
36	Well Pump Engine	Detroit Diesel 4031-C	3563	1995	Distillate	220	hp
Material Handling - Ash							
51a	Fly Ash Dust Collector (DC-1)	United Conveyor Corp. 32242	CHPP	1993	N/A	3,620	acfm
51b	Bottom Ash Dust Collector (DC-2)	United Conveyor Corp. 32242	CHPP	1994	N/A	3,620	acfm
Material Handling - Coal Pile							
52	Coal Storage Pile	CHPP	CHPP	Unknown	N/A	N/A	N/A

Table 3.2
Fort Wainwright Significant Emission Units for BACT Analysis

Emission Unit				Installation Date	Fuel Type	Rating	
ID	Name	Description	Bldg. No.				
Distillate Fired Boilers							
			1171	N/A	Distillate	0.2	MMBTU/Hr
			1172	N/A	Distillate	0.9	MMBTU/Hr
			1172	N/A	Distillate	0.2	MMBTU/Hr
			1185	N/A	Distillate	1.3	MMBTU/Hr
			1185	N/A	Distillate	1.3	MMBTU/Hr
			1191	N/A	Distillate	0.2	MMBTU/Hr
			2092	N/A	Distillate	0.4	MMBTU/Hr
			2092	N/A	Distillate	0.4	MMBTU/Hr
			2096	N/A	Distillate	0.8	MMBTU/Hr
			2096	N/A	Distillate	0.8	MMBTU/Hr
			2400	N/A	Distillate	0.3	MMBTU/Hr
			4076	N/A	Distillate	19.0	MMBTU/Hr
			4076	N/A	Distillate	19.0	MMBTU/Hr
			4076	N/A	Distillate	19.0	MMBTU/Hr
			4321	N/A	Distillate	0.3	MMBTU/Hr
			4322	N/A	Distillate	0.3	MMBTU/Hr
			5003	N/A	Distillate	0.3	MMBTU/Hr
			5007	N/A	Distillate	2.5	MMBTU/Hr
			5008	N/A	Distillate	0.4	MMBTU/Hr
			5009	N/A	Distillate	0.2	MMBTU/Hr
			5010	N/A	Distillate	0.9	MMBTU/Hr
			5109	N/A	Distillate	0.2	MMBTU/Hr
			5110	N/A	Distillate	0.2	MMBTU/Hr
			5113	N/A	Distillate	0.1	MMBTU/Hr
			5119	N/A	Distillate	0.1	MMBTU/Hr
			5175	N/A	Distillate	0.1	MMBTU/Hr
			KDR	N/A	Distillate	0.1	MMBTU/Hr
Waste Oil Boilers							
						43800.0	gal/yr
Emergency and Black Start Generators							
	Black Start Generator Engine	Clarke DDFP-04AT	1572	1994	Distillate	235 hp	Clarke DDFP-04AT
	Generator Engine	Clarke DDFP-04AT	1572	1994	Distillate	235 hp	Clarke DDFP-04AT

Table 3.2
Fort Wainwright Significant Emission Units for BACT Analysis (continued)

Emission Unit				Installation Date	Fuel Type	Rating	
ID	Name	Description	Bldg. No.				
Emergency and Black Start Generators (continued)							
	Generator Engine	Clarke DDFP-04AT	1572	1994	Distillate	235 hp	Clarke DDFP-04AT
	Generator Engine	Clarke DDFP-04AT	1572	1994	Distillate	235 hp	Clarke DDFP-04AT
	Generator Engine	CumminsN-855-F	2080	1977	Distillate	240 hp	CumminsN-855-F
	Generator Engine	Cummins N-855-F	2080	1977	Distillate	240 hp	Cummins N-855-F
	Generator Engine	Clarke JW64-UF30	2089	2007	Distillate	275 hp	Clarke JW64-UF30
	Generator Engine	Cummins N-855-F	3011	1977	Distillate	240 hp	Cummins N-855-F
	Generator Engine	Cummins N-855-F	3011	1977	Distillate	240 hp	Cummins N-855-F
	Generator Engine	Cummins N-855-F	3011	1977	Distillate	240 hp	Cummins N-855-F
	Generator Engine	Cummins N-855-F	3011	1977	Distillate	240 hp	Cummins N-855-F
	Generator Engine	Clarke JU4H-UF40	3498	2005	Distillate	94 hp	Clarke JU4H-UF40
	Generator Engine	Clarke PDFP-06YT	5009	1996	Distillate	120 hp	Clarke PDFP-06YT
	Generator Engine	Clarke PDFP-06YT	5009	1996	Distillate	120 hp	Clarke PDFP-06YT
	Diesel Emergency Engine	Cummins QSB7-G3 NR3	Hangar	2012	Diesel	134 hp	Cummins QSB7-G3 NR3
	Diesel Emergency Engine	John Deere 4024HF285B	1580	2009	Diesel	67 hp	John Deere 4024HF285B
	Diesel Emergency Engine	CAT C9 GENSET	3406	2007	Diesel	335 hp	CAT C9 GENSET
	Diesel Emergency Engine	SDMO TM30UCM	3567	ND	Diesel	47 hp	SDMO TM30UCM
	Diesel Emergency Engine	Cat 3512	4076	2003	Diesel	1206 hp	Cat 3512
	Diesel Emergency Engine	Cat 3512	4076	2003	Diesel	1206 hp	Cat 3512
	Diesel Emergency Engine	Cat 3512	4076	2003	Diesel	1206 hp	Cat 3512

Table 3.3
PM_2 Emissions Calculations

Filterable PM from "Source Emission Testing Report, Doyon Utilities LLC, June 15-20, 2016, Air Pollution Testing, Inc.	**Emission Unit**					
	3	**4**	**5**	**6**	**7**	**8**
Flow (dscfm)	39416	38521	38793	37870	39077	38555
Fd (dscf/MMBTU)	9612	9612	9612	9612	9612	9612
O2 (%)	5.4	4.8	4.9	5	5.1	4.5
PM (gr/dscf)[1]	0.001	0.006	0.001	0.002	0.001	0.002
PM (lb/MMBTU)	**0.001**	**0.011**	**0.001**	**0.003**	**0.001**	**0.004**
MACTEC guidance on CPM emissions (to Mid Atlantic Regional Air Management Association) August 2008						
CPM (lb/MMBTU)	0.015	0.015	0.015	0.015	0.015	0.015
Calculated total CPM+FPM(lb/MMBTU)	0.01648	0.026	0.015997	0.01795	0.01606	0.0189
So, to convert back to gr/dscf assuming this CPM loading rate (see calculations from MACT report, page 124)						
Mt/Vmstd	0.0006	0.0009	0.0006	0.0006	0.0006	0.0007
calculated total for CPM+FPM (gr/dscf)[2]	**0.009**	**0.015**	**0.009**	**0.010**	**0.009**	**0.011**
CPM+FPM (lb/MMBTU)[3]	0.017	0.029	0.016	0.019	0.016	0.020
CPM+FPM (lb/ton)[4]	0.27	0.46	0.26	0.30	0.26	0.32
Assumed: Heat Content of Coal	8000 BTU/lb					

1 Total filterable PM - not just PM2.5

2 Includes the confidence interval for CPM; additionally assumes the total FPM represents PM2.5

3 Uses confidence interval for the CPM data and 25% safety factor for the FPM testing data; additional safety factor present since testing was total filterable matter.

4 Using the highest heat rating from Usibelli data (7200-8000) btu/lb

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Table 5.1
Central Heat and Power Plant RBLC Review - NO_x

RBLC ID	Facility Name	State	Date of Determination	Process	Primary Fuel	Pollutant	Control Method	Throughput	Units	Emissions Limit	Units	Avg Condition	Basis
AZ-0055	Navaho Generating Station	AZ	11/12/2012	Pulverized Coal Fired Boiler	Coal	NO_x	Low NO_x Burner (LNB), Separated Overfire Air (SOFA) System	7725	MMBTU/HR	0.24	LB/MMBTU	30-Day Rolling Avg	BACT-PSD
AZ-0055	Navaho Generating Station	AZ	11/12/2012	Pulverized Coal Fired Boiler	Coal	NO_x	LNB, SOFA System	7725	MMBTU/HR	0.24	LB/MMBTU	30-Day Rolling Avg	BACT-PSD
AZ-0055	Navaho Generating Station	AZ	11/12/2012	Pulverized Coal Fired Boiler	Coal	NO_x	LNB, SOFA System	7725	MMBTU/HR	0.24	LB/MMBTU	30-Day Rolling Avg	BACT-PSD
ND-0026	M.R. Young Station	ND	2/28/2012	Cyclone Boilers, Unit 1	Lignite	NO_x	SNCR plus SOFA	3200	MMBTU/HR	0.36	LB/MMBTU	30-Day Rolling Avg	BACT-PSD
ND-0026	M.R. Young Station	ND	2/28/2012	Cyclone Boilers, Unit 2	Lignite	NO_x	SNCR plus SOFA	6300	MMBTU/HR	0.35	LB/MMBTU	30-Day Rolling Avg	BACT-PSD
OK-0151	Sooner Generating Station	OK	6/16/2014	Coal-Fired Boilers	Coal	NO_x	LNB and Overfire Air	550	MW	0.15	LB/MMBTU	30-Day Avg	BART
OK-0152	Muskogee Generating Station	OK	6/17/2014	Coal-Fired Boilers	Coal	NO_x	LNB and Overfire Air	550	MW	0.15	LB/MMBTU	30-Day Avg	BART

Table 5.2
Central Heat and Power Plant RBLC Review - SO_2

RBLC ID	Facility Name	State	Date of Determination	Process	Primary Fuel	Pollutant	Control Method	Throughput	Units	Emissions Limit	Units	Avg Condition	Basis
AZ-0055	Navajo Generating Station	AZ	11/12/2012	Pulverized Coal Fired Boiler	Coal	SO_2	Flue Gas Desulfurization (FGD), Scrubber	7725	MMBTU/H				
AZ-0055	Navajo Generating Station	AZ	11/12/2012	Pulverized Coal Fired Boiler	Coal	SO_2	FGD, Scrubber	7725	MMBTU/H				
AZ-0055	Navajo Generating Station	AZ	11/12/2012	Pulverized Coal Fired Boiler	Coal	SO_2	FGD, Scrubber	7725	MMBTU/H				

Table 5.3
Central Heat and Power Plant RBLC Review - PM

RBLC ID	Facility Name	State	Date of Determination	Process	Primary Fuel	Pollutant	Control Method	Throughput	Units	Emissions Limit	Units	Avg Condition	Basis
WI-0253	Oak Street Station	WI	9/18/2015	Outdoor coal storage	None	PM, Fugitive	Fugitive dust plan that includes: trained Method 9 observer; water sprays; wind barrier; crusting agents; video monitoring of the coal piles; study of additional control measures for feasibility	N/A	N/A	7.5	OPACITY %	6 MINUTES	BACT-PSD
TX-0700	Limestone Electric Generating Station	TX	3/19/2015	(2) coal-fired boilers	PRB coal	PM (Total and LT) (10)	Electrostatic Precipitators and Wet Flue Gas Desulfurization	900	MW	0.03	LB/MMBTU		
WY-0073	Jim Bridger Power Plant	WY	6/13/2013	Unit 3	Coal	PM (Total and LT) (10)	Utilize existing WFGD and ESP	6000	MMBTU/HR	0.0418	LB/MMBTU	3-HR AVERAGE	BACT-PSD
WY-0073	Jim Bridger Power Plant	WY	6/13/2013	Unit 4	Coal	PM (Total and LT) (10)	Utilize existing WFGD and ESP	6000	MMBTU	0.0397	LB/MMBTU	3-HR AVERAGE	BACT-PSD
TX-0700	Limestone Electric Generating Station	TX	3/19/2015	(2) coal-fired boilers	PRB coal	PM (Total and LT) (2.5)	Electrostatic Precipitators and Wet Flue Gas Desulfurization	900	MW	0.03	LB/MMBTU		
WY-0073	Jim Bridger Power Plant	WY	6/13/2013	Unit 3	Coal	PM (Total and LT) (2.5)	Utilize existing WFGD and ESP	6000	MMBTU/HR	0.0205	LB/MMBTU	3-HR AVERAGE	BACT-PSD
WY-0073	Jim Bridger Power Plant	WY	6/13/2013	Unit 4	Coal	PM (Total and LT) (2.5)	Utilize existing WFGD and ESP	6000	MMBTU	0.018	LB/MMBTU	3-HR AVERAGE	BACT-PSD
TX-0700	Limestone Electric Generating Station	TX	3/19/2015	(2) coal-fired boilers	PRB coal	PM (Total)	Electrostatic Precipitators and Wet Flue Gas Desulfurization	900	MW	0.03	LB/MMBTU		

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Table 6.1
Engines, Generators, and Pumps RBLC Review - NO_x

RBLC ID	Facility Name	State	Date of Determination	Process	Primary Fuel	Pollutant	Control Method	Throughput	Units	Emissions Limit	Units	Avg Condition	Basis
*LA-0296	Lake Charles Chemical Complex LDPE Unit	LA	9/12/2016	Emergency Diesel Generators (EQTs 622, 671, 773, 850, 994, 995, 996, 1033, 1077, 1105, & 1202)	Diesel	NO_x	Compliance with 40 CFR 60 Subpart IIII; operating the engine in accordance with the engine manufacturer's instructions and/or written procedures (consistent with safe operation) designed to maximize combustion efficiency and minimize fuel usage.	2682	HP	27.37	LB/HR	Hrly Max	BACT-PSD
*LA-0305	Lake Charles Methanol Facility	LA	3/7/2017	Diesel Engines (Emergency)	Diesel	NO_x	Complying with 40 CFR 60 Subpart IIII	4023	HP				BACT-PSD
*LA-0307	Magnolia LNG Facility	LA	3/8/2017	Diesel Engines	Diesel	NO_x	good combustion practices, Use ultra low sulfur diesel, and comply with 40 CFR 60 Subpart IIII						BACT-PSD
*LA-0309	Benteler Steel Tube Facility	LA	3/9/2017	Emergency Generator Engines	Diesel	NO_x	Complying with 40 CFR 60 Subpart IIII	2922	HP (each)	6.4	G/KW-HR		BACT-PSD
*LA-0309	Benteler Steel Tube Facility	LA	3/9/2017	Firewater Pump Engines	Diesel	NO_x	Complying with 40 CFR 60 Subpart IIII	288	HP (each)	3	G/BHP-HR		BACT-PSD
*LA-0315	G2G Plant	LA	3/13/2017	Emergency Diesel Generator 1	Diesel	NO_x	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	5364	HP	52.58	LB/H	Hrly Max	BACT-PSD
*LA-0315	G2G Plant	LA	3/13/2017	Emergency Diesel Generator 2	Diesel	NO_x	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	5364	HP	52.58	LB/H	Hrly Max	BACT-PSD
*LA-0315	G2G Plant	LA	3/13/2017	Fire Pump Diesel Engine 1	Diesel	NO_x	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	751	HP	4.6	LB/H	Hrly Max	BACT-PSD
*LA-0316	Cameron LNG Facility	LA	3/14/2017	emergency generator engines (6 units)	Diesel	NO_x	Complying with 40 CFR 60 Subpart IIII	3353	HP				BACT-PSD
*LA-0316	Cameron LNG Facility	LA	3/14/2017	firewater pump engines (8 units)	Diesel	NO_2	Complying with 40 CFR 60 Subpart IIII	460	HP				BACT-PSD
*LA-0317	Methanex - Geismar Methanol Plant	LA	3/15/2017	Emergency Generator Engines (4 units)	Diesel	NO_x	complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ						BACT-PSD
*LA-0317	Methanex - Geismar Methanol Plant	LA	3/15/2017	Firewater pump Engines (4 units)	Diesel	NO_x	complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	896	HP (each)				BACT-PSD
*MD-0042	Wildcat Point Generation Facility	MD	7/31/2015	Emergency diesel engine for fire water pump	ULSD	NO_x	Limited operating hours, use of ultra-low sulfur fuel and good combustion practices	477	HP	3	G/HP-H		LAER
*MD-0042	Wildcat Point Generation Facility	MD	7/31/2015	Emergency generator 1	ULSD	NO_x	Limited operating hours, use of ultra-low sulfur fuel and good combustion practices	2250	KW	4.8	G/HP-H		LAER
*OK-0145	Broken Bow OSB Mill	OK	6/13/2014	Emerg Diesel Gen, Fire Pump, Rail Steam Gen, Air Makeup Units	Diesel	NO_x							BACT-PSD
*VA-0325	Greensville Power Station	VA	9/16/2016	Diesel-fired Emergency Generator 3000 kW (1)	Diesel Fuel	NO_x	Good Combustion Practices/Maintenance			6.4	G/KW	Per Hr	N/A
*VA-0325	Greensville Power Station	VA	9/16/2016	Diesel-fired water pump 376 bph (1)	Diesel Fuel	NO_x	Good Combustion Practices/Maintenance						N/A
*WV-0025	Moundsville Combined Cycle Power Plant	WV	1/5/2015	Emergency Generator	Diesel	NO_x		2015.7	HP				BACT-PSD
*WV-0025	Moundsville Combined Cycle Power Plant	WV	1/5/2015	Fire Pump Engine	Diesel	NO_x		251	HP				BACT-PSD
*WY-0070	Cheyenne Prairie Generating Station	WY	8/23/2012	Diesel Emergency Generator (EP15)	ULSD	NO_x	EPA Tier 2 rated	839	HP				BACT-PSD
*WY-0070	Cheyenne Prairie Generating Station	WY	8/23/2012	Diesel Fire Pump Engine (EP16)	ULSD	NO_x	EPA Tier 3 rated	327	HP				BACT-PSD
AK-0076	Point Thomson Production Facility	AK	8/23/2012	Combustion of Diesel by Engines	ULSD	NO_x		1750	kW	6.4	G/KW-H		BACT-PSD
AK-0082	Point Thomson Production Facility	AK	1/28/2015	Agitator Generator Engine	ULSD	NO_x		98	HP	5.6	GRAMS/HP-H		BACT-PSD
AK-0082	Point Thomson Production Facility	AK	1/28/2015	Airstrip Generator Engine	ULSD	NO_x		490	HP	4.8	GRAMS/HP-H		BACT-PSD
AK-0082	Point Thomson Production Facility	AK	1/28/2015	Bulk Tank Generator Engines	ULSD	NO_x		891	HP	4.8	GRAMS/HP-H		BACT-PSD
AK-0082	Point Thomson Production Facility	AK	1/28/2015	Fine Water Pumps	ULSD	NO_x		610	HP	3	GRAMS/HP-H		BACT-PSD
AK-0083	Kenai Nitrogen Operations	AK	1/29/2015	Diesel Fired Well Pump	Diesel	NO_x	Limited Operation of 168 hr/yr.	2.7	MMBTU/HR	4.41	LB/MMBTU		BACT-PSD
AR-0140	Big River Steel LLC	AR	11/9/2016	Emergency Generator SN-62	Diesel	NO_x	Good operating practices, limited hours of operation, complicance with NSPS Subpart IIII	625	HP	0.4	G/KW-H		BACT-PSD
AR-0140	Big River Steel LLC	AR	11/9/2016	Emergency Generator SN-62	Diesel	NO_2	Good combustion practices	625	HP	0.67	LB/MMBTU		BACT-PSD
AR-0140	Big River Steel LLC	AR	11/9/2016	Emergency Generators	Diesel	NO_2	Good combustion practices	1500	KW	0.0013	LB/MMBTU		BACT-PSD
FL-0347	Anadarko Petroleum Corporation - EGOM	FL	9/21/2015	Emergency Diesel Engine	Diesel	NO_x	Use of good combustion practices based on the most recent manufacturer's specifications issued for engines and with turbocharger, aftercooler, and high injection pressure	3300	HP				BACT-PSD
FL-0354	Lauderdale Plant	FL	2/17/2016	Emergency fire pump engine, 300 HP	Diesel	NO_x	Low-emitting fuel and certified engine	29	MMBTU/HR	4	G / KWH	NMHC + NO_X (Subpart IIII)	BACT-PSD
IA-0105	Iowa Fertilizer Company	IA	11/1/2012	Emergency Generator	Diesel Fuel	NO_x	Good combustion practices	142	GAL/HR	6	G/KW-H	Avg of 3 stack test runs	BACT-PSD
IA-0105	Iowa Fertilizer Company	IA	11/1/2012	Fire Pump	Diesel Fuel	NO_x	Good combustion practices	14	GAL/HR	3.75	G/KW-H	Avg of 3 stack test runs	BACT-PSD
IL-0114	Cronus Chemicals, LLC	IL	12/24/2014	Emergency Generator	Distillate Fuel Oil	NO_x	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7.	3755	HP	0.67	G/KW-H		BACT-PSD
IL-0114	Cronus Chemicals, LLC	IL	12/24/2014	Firewater Pump Engine	Distillate Fuel Oil	NO_x	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7.	373	HP	3.5	G/KW-H		BACT-PSD
IN-0158	St. Joseph Energy Center, LLC	IN	8/15/2013	Emergency Diesel Generator	Diesel	NO_x	Combustion design controls and usage limits	2012	HP	4.8	G/HP-H	3 Hrs	BACT-PSD
IN-0158	St. Joseph Energy Center, LLC	IN	8/15/2013	Two (2) Emergency Diesel Generators	Diesel	NO_x	Combustion design controls and usage limits	1006	HP EACH	4.8	G/HP-H	3 Hrs	BACT-PSD
IN-0158	St. Joseph Energy Center, LLC	IN	8/15/2013	Two (2) Firewater Pump Diesel Engines	Diesel	NO_x	Combustion design controls and usage limits	371	BHP, EACH	3	G/HP-H	3 Hrs	BACT-PSD
IN-0166	Indiana Gasification, LLC	IN	8/16/2013	Three (3) Firewater Pump Engines	Diesel	NO_x	Good combustion practices and limited hours of non-emergency operation	575	HP EACH				BACT-PSD
IN-0166	Indiana Gasification, LLC	IN	8/16/2013	Two (2) Emergency Generators	Diesel	NO_x	Good combustion practices and limited hours of non-emergency operation	1341	HP EACH				BACT-PSD

Table 6.1
Engines, Generators, and Pumps RBLC Review - NO_x

RBLC ID	Facility Name	State	Date of Determination	Process	Primary Fuel	Pollutant	Control Method	Throughput	Units	Emissions Limit	Units	Avg Condition	Basis
IN-0173	Midwest Fertilizer Corporation	IN	7/17/2014	Diesel Fired Emergency Generator	No. 2, Diesel	NO_x	Good combustion practices	3600	BHP	4.46	G/BHP-H	3-Hr Avg	BACT-PSD
IN-0173	Midwest Fertilizer Corporation	IN	7/17/2014	Fire Pump		NO_x	Good combustion practices	500	HP	2.83	G/BHP-H	3-Hr Avg	BACT-PSD
IN-0179	Ohio Valley Resources, LLC	IN	8/12/2014	Diesel Fired Emergency Generator	No. 2 Fuel Oil	NO_x	Good combustion practices	4690	B-HP	4.46	G/B-HP-H	3-Hr Avg	BACT-PSD
IN-0179	Ohio Valley Resources, LLC	IN	8/12/2014	Diese-Fired Emergency Water Pump	No. 2 Fuel Oil	NO_x	Good combustion practices	481	BHP	2.86	G/B-HP-H	3-Hr Avg	BACT-PSD
IN-0180	Midwest Fertilizer Corporation	IN	8/12/2014	Diesel Fired Emergency Generator	No. 2, Diesel	NO_x	Good combustion practices	3600	BHP	4.46	G/B-HP-H	3-Hr Avg	BACT-PSD
IN-0180	Midwest Fertilizer Corporation	IN	8/12/2014	Fire Pump		NO_x	Good combustion practices	500	HP	2.83	G/B-HP-H	3-Hr Avg	BACT-PSD
IN-0185	MAG Pellet LLC	IN	8/12/2014	Diesel Fire Pump	Diesel	NO_x		300	HP	3	G/HP-H		BACT-PSD
IN-0202	IPL Eagle Valley Generating Station	IN	5/11/2015	Emergency Fire Pump EU-6	Diesel	NO_2	Low NO_x Burner and Flue Gas Recirculation	500	HP	0.032	LB/MMBTU	3-Hr Avg	Other case-by-case
IN-0234	Grain Processing Corporation	IN	2/25/2016	Emergency Fire Pump Engine	Distillate Oil	NO_x	Good combustion practices			9.5	G/HP-H		BACT-PSD
LA-0288	Lake Charles Chemical Complex	LA	7/22/2016	Emergency Diesel Generators (EQT 629, 639, 838, 966, & 1264)		NO_x	Comply with 40 CFR 60 Subpart IIII; operate the engine in accordance with the engine manufacturer's instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage.	2682	HP	27.37	LB/HR	Hrly Max	BACT-PSD
LA-0292	Holbrook Compressor Station	LA	8/4/2016	Emergency Generators No. 1 & No. 2	Diesel	NO_x	Good equipment design, proper combustion techniques, use of low sulfur fuel, and compliance with 40 CFR 60 Subpart IIII	1341	HP	14.16	LB/HR	Hrly Max	BACT-PSD
MA-0039	Salem Harbor Station Redevelopment	MA	9/26/2014	Emergency Engine/Generator	ULSD	NO_x		7.4	MMBTU/HR	4.8	GM/BHP-H	1 Hr Block Avg	LAER
MA-0039	Salem Harbor Station Redevelopment	MA	9/26/2014	Fire Pump Engine	ULSD	NO_x		2.7	MMBTU/HR	3	GM/BHP-H	1 Hr Block Avg	LAER
MD-0044	Cove Point LNG Terminal	MD	8/25/2015	5 Emergency Fire Water Pump Engines	ULSD	NO_x	Good combustion practices and designed to achieve emission limit	350	HP	3	G/HP-H	NO_X + NMHC	LAER
MD-0044	Cove Point LNG Terminal	MD	8/25/2015	Emergency Generator	ULSD	NO_x	Good combustion practices and designed to achieve emission limit	1550	HP	4.8	G/HP-H	Combined NO_X + NMHC	LAER
MD-0046	Keys Energy Center	MD	12/23/2015	Diesel-Fired Auxilliary (Emergency) Engines (two)	ULSD	NO_x	Exclusive use of ultra low sulfur fuel and good combustion practices	1500	KW	6.4	G/KW-H	0	BACT-PSD
MD-0046	Keys Energy Center	MD	12/23/2015	Diesel-Fired Fire Pump Engine	ULSD	NO_x	Exclusive use of ultra low sulfur diesel fuel and good combustion practices	300	HP	4	G/KW-H	0	BACT-PSD
MI-0406	Renaissance Power LLC	MI	3/19/2014	FG-EMGEN7-8; Two (2) 1,000kW diesel-fueled emergency reciprocating internal combustion engines	Diesel	NO_x	Good combustion practices	1000	kW	4.8	G/B-HP-H	Test protocol; each unit	BACT-PSD
MI-0410	Thetford Generating Station	MI	8/1/2014	EU-FPENGINE: Diesel fuel fired emergency backup fire pump	Diesel Fuel	NO_x	Proper combustion design and ultra low sulfur diesel fuel.	315	HP nameplate	3	G/HP-H	Test protocol will specify Avg time	BACT-PSD
MI-0412	Holland Board of Public Works - East 5th Street	MI	8/15/2014	Emergency Engine --Diesel Fire Pump (EUFPENGINE)	Diesel	NO_x	Good combustion practices	165	HP	3	G/HP-H	Test protocol	BACT-PSD
NJ-0079	Woodbridge Energy Center	NJ	11/27/2012	Emergency Generator	ULSD	NO_x	Use of ULSD diesel oil	100	H/YR	21.16	LB/H		LAER
NJ-0081	PSEG Fossil LLC Sewaren Generating Station	NJ	8/22/2014	Emergency diesel fire pump	ULSD	NO_x				1.75	LB/H		LAER
NJ-0084	PSEG Fossil LLC Sewaren Generating Station	NJ	5/13/2016	Diesel Fired Emergency Generator	ULSD	NO_x	use of ultra low sulfur diesel a clean burning fuel.	44	H/YR	42.3	LB/H		LAER
NJ-0084	PSEG Fossil LLC Sewaren Generating Station	NJ	5/13/2016	Emergency Diesel Fire Pump	ULSD	NO_x	use of ULSD a clean burning fuel, and limited hours of operation	100	H/YR	1.7	LB/H		LAER
NJ-0085	Middlesex Energy Center, LLC	NJ	7/27/2016	Emergency diesel fire pump	ULSD	NO_x	Use of Ultra Low Sulfur Diesel (ULSD) Oil a clean burning fuel and limited hours of operation	100	H/YR	2.05	LB/H		LAER
NJ-0085	Middlesex Energy Center, LLC	NJ	7/27/2016	Emergency Generator Diesel	Diesel Oil	NO_x	Use of Ultra Low Sulfur Diesel (ULSD) Oil a clean burning fuel and limited hours of operation		100 H/YR	20.6	LB/H		LAER
OH-0352	Oregon Clean Energy Center	OH	7/15/2013	Emergency fire pump engine	Diesel	NO_x	Purchased certified to the standards in NSPS Subpart IIII	300	HP	1.7	LB/H		BACT-PSD
OH-0352	Oregon Clean Energy Center	OH	7/15/2013	Emergency generator	Diesel	NO_x	Purchased certified to the standards in NSPS Subpart IIII	2250	KW	27.8	LB/H		BACT-PSD
OK-0154	Moreland Generating Station	OK	6/18/2014	Diesel-Fired Emergency Generator Engine	Diesel	NO_x	Combustion control	1341	HP	0.011	LB/HP-HR		BACT-PSD
PA-0278	Moxie Liberty LLC/Asylum Power Plant	PA	12/3/2012	Emergency Generator	Diesel	NO_x				4.93	G/B-HP-H		Other case-by-case
PA-0278	Moxie Liberty LLC/Asylum Power Plant	PA	12/3/2012	Fire Pump	Diesel	NO_x				2.6	G/B-HP-H		Other case-by-case
PA-0286	Moxie Energy LLC/Patriot Generation Plant	PA	3/27/2013	Emergency Generator-Engine	Diesel	NO_x				4.93	GM/B-HP-H		Other case-by-case
PA-0286	Moxie Energy LLC/Patriot Generation Plant	PA	3/27/2013	Fire Pump Engine - 460 BHP	Diesel	NO_x				2.6	G/HP-H	Expressed as NO_2	Other case-by-case
PR-0009	Energy Answers Arecibo Puerto Rico Renewable Energy Project	PR	10/14/2014	Emergency Diesel Fire Pump	ULSD Fuel Oil #2	NO_x				2.85	G/B-HP-H		BACT-PSD
PR-0009	Energy Answers Arecibo Puerto Rico Renewable Energy Project	PR	10/14/2014	Emergency Diesel Generator	ULSD Fuel oil # 2	NO_x				2.85	G/B-HP-H		BACT-PSD
SC-0113	Pyramax Ceramics, LLC	SC	5/9/2012	Emergency Engine 1 thru 8	Diesel	NO_x	Purchase of certified engine	29	HP	7.5	GR/KW-H		BACT-PSD
SC-0113	Pyramax Ceramics, LLC	SC	5/9/2012	Emergency Generators 1 thru 8	Diesel	NO_x	Engines must be certified to comply with NSPS, Subpart IIII	757	HP	4	GR/KW-H		BACT-PSD
SC-0113	Pyramax Ceramics, LLC	SC	5/9/2012	Fire Pump	Diesel	NO_x	Purchase of certified engine based on NSPS, Subpart IIII	500	HP	4	GR/KW-H		BACT-PSD

Table 6.2
Engines, Generators, and Fire Pumps

Location	EU	Make	Description	Year	Status	Size (hp)	Annual Operating Limits (non-Emergency)	Proposed BACT
DU	8	Caterpillar 3516C	Backup Generator Engine	2009	Certified Engine	2,937	500	Comply with 40 CFR 60 Subpart IIII
FWA	11	Caterpillar	3512	2003	N/A	1454	200	Current Owner Requested Limit of 600 hours/12-month period cumulative for these three engines.
FWA	12	Caterpillar	3512	2003	N/A	1454	200	
FWA	13	Caterpillar	3512	2003	N/A	1454	200	
DU	15	Detroit R1237M36	Generator Engine	2005	Mfg Information	1,059	500	Good Housekeeping Practices
DU	10	Caterpillar C15	Generator Engine	2010	Certified Engine	762	500	Comply with 40 CFR 60 Subpart IIII
DU	11	Caterpillar C15	Generator Engine	2010	Certified Engine	762	500	Comply with 40 CFR 60 Subpart IIII
DU	13	Caterpillar 3406C TA	Generator Engine	2008	Certified Engine	587	500	Comply with 40 CFR 60 Subpart IIII
FWA	28	Caterpillar	CAT C9 GENSET	2007	Certified Engine	398	500	Comply with 40 CFR 60 Subpart IIII
DU	9	Detroit 6V92	Generator Engine	1988	N/A	353	500	Good Housekeeping Practices
DU	14	Cummins QSL-G2 NR3	Generator Engine	2008	Certified Engine	320	500	Comply with 40 CFR 60 Subpart IIII
FWA	26	Cummins	QSB7-G3 NR3	2012	Certified Engine	295	500	Comply with 40 CFR 60 Subpart IIII
FWA	30	John Deere	JW64-UF30	2007	Certified Engine	275	500	Comply with 40 CFR 60 Subpart IIII
DU	27	Caterpillar C6.6	Generator Engine	2010	Certified Engine	274	500	Comply with 40 CFR 60 Subpart IIII
DU	28	Caterpillar C6.6	Generator Engine	2010	Certified Engine	274	500	Comply with 40 CFR 60 Subpart IIII
FWA	35	Cummins	N-855-F	1977	N/A	240	500	Good Combustion Practices
FWA	36	Cummins	N-855-F	1977	N/A	240	500	Good Combustion Practices
FWA	31	Clarke	DDFP-04AT	1994	N/A	235	500	Good Combustion Practices
FWA	32	Clarke	DDFP-04AT	1994	N/A	235	500	Good Combustion Practices
FWA	33	Clarke	DDFP-04AT	1994	N/A	235	500	Good Combustion Practices
FWA	34	Clarke	DDFP-04AT	1994	N/A	235	500	Good Combustion Practices
DU	34	Detroit Diesel 10447000	Well Pump Engine	1995	N/A	220	500	Good Combustion Practices
DU	36	Detroit Diesel 4031-C	Well Pump Engine	1995	N/A	220	500	Good Combustion Practices
DU	16	John Deere 6068TF250	Generator Engine	2005	N/A	212	500	Good Combustion Practices
DU	18	John Deere 6068HF150	Generator Engine	2005	N/A	212	500	Good Combustion Practices
DU	17	John Deere 6068TF250	Generator Engine	2007	Permit condition 23.1c	176	500	Good Combustion Practices
DU	23	John Deere 6068HF150	Generator Engine	2003	N/A	155	500	Good Combustion Practices
FWA	38	Clarke	PDFP-06YT	1996	N/A	120	500	Good Combustion Practices
FWA	39	Clarke	PDFP-06YT	1996	N/A	120	500	Good Combustion Practices
DU	21	Perkins 2046/1800	Generator Engine	2001	N/A	95	500	Good Combustion Practices
FWA	37	Clarke	JU4H-UF40	2005	N/A	94	500	Good Combustion Practices
DU	12	Cummins B3.3	Generator Engine	2002	N/A	82	500	Good Combustion Practices
DU	30	Detroit Diesel 10245100	Lift Pump Engine	1952	N/A	75	500	Good Combustion Practices
DU	32	Perkins	Lift Pump Engine	1955	N/A	75	500	Good Combustion Practices
DU	33	Perkins	Lift Pump Engine	1994	N/A	75	500	Good Combustion Practices
DU	29a	John Deere 4045TF290	Lift Pump Engine	2014	Certified Engine	74	500	Comply with 40 CFR 60 Subpart IIII
DU	31a	John Deere 4045TF290	Lift Pump Engine	2014	Certified Engine	74	500	Comply with 40 CFR 60 Subpart IIII
DU	19	John Deere 4045TF270	Generator Engine	2007	Certified Engine	71	500	Comply with 40 CFR 60 Subpart IIII

Table 6.2
Engines, Generators, and Fire Pumps

Location	EU	Make	Description	Year	Status	Size (hp)	Annual Operating Limits (non-Emergency)	Proposed BACT
DU	26	Cummins 4B3.9-G2	Generator Engine	2003	N/A	68	500	Good Combustion Practices
FWA	27	John Deere	4024HF285B	2009	Certified Engine	67	500	Comply with 40 CFR 60 Subpart IIII
DU	35	John Deere 4045DF120	Well Pump Engine	2009	Certified Engine	55	500	Comply with 40 CFR 60 Subpart IIII
DU	24	Cummins L634D-I/10386E	Generator Engine	1993	N/A	50	500	Good Combustion Practices
FWA	29	SDMO	TM30UCM	ND	N/A	47	500	Good Combustion Practices
DU	20	John Deere 4239D	Generator Engine	1976	N/A	35	500	Good Combustion Practices
DU	22	Cummins	Generator Engine	1989	N/A	35	500	Good Combustion Practices
DU	25	Caterpillar C1.5	Generator Engine	2011	Certified Engine	18	500	Comply with 40 CFR 60 Subpart IIII

Table 6.3
Engines, Generators, and Pumps RBLC Review - SO_2

RBLC ID	Facility Name	State	Date of Determination	Process	Primary Fuel	Pollutant	Control Method	Throughput	Units	Emissions Limit	Units	Avg Condition	Basis
*LA-0296	Lake Charales Chemical Complex LDPE Unit	LA	9/12/2016	Emergency Diesel Generators (EQTs 622, 671, 773, 850, 994, 995, 996, 1033, 1077, 1105, & 1202)	Diesel	SO_2	Compliance with 40 CFR 60 Subpart IIII; operating the engine in accordance with the engine manufacturer's instructions and/or written procedures (consistent with safe operation) designed to maximize combustion efficiency and minimize fuel usage.	2682	HP	0.03	LB/HR	Hrly Max	BACT-PSD
*LA-0305	Lake Charles Methanol Facility	LA	3/7/2017	Diesel Engines (Emergency)	Diesel	SO_2	Complying with 40 CFR 60 Subpart IIII	4023	HP				BACT-PSD
*LA-0309	Benteler Steel Tube Facility	LA	3/9/2017	Emergency Generator Engines	Diesel	SO_2		2922	HP (each)				BACT-PSD
*LA-0309	Benteler Steel Tube Facility	LA	3/9/2017	Firewater Pump Engines	Diesel	SO_2		288	HP (each)				BACT-PSD
*MD-0042	Wildcat Point Generation Facility	MD	7/31/2015	Emergency diesel engine for fire water pump	ULSD	SO_2	Use of ULSD fuel, limited hours of operation and designed to meet subpart IIII limits	477	HP	0.0049	G/B-HP-H	3-hr block average	BACT-PSD
*MD-0042	Wildcat Point Generation Facility	MD	7/31/2015	Emergency Generator 1	ULSD	SO_2	Use of ULSD fuel, limited hours of operation and designed to meet NSPS subpart IIII limits	2250	KW	0.006	G/B-HP-H	3-hr block average	BACT-PSD
*VA-0325	Greensville Power Station	VA	9/16/2016	Diesel-fired emergency generator 3000 kW (1)	Diesel fuel	SO_2	ULSD/Fuel (15 ppm max)			0.0015	LB/MMBTU		N/A
*VA-0325	Greensville Power Station	VA	9/16/2016	Diesel-fired water pump 376 bph (1)	Diesel fuel	SO_2	ULSD/Fuel (15 ppm max)			0.0015	LB/MMBTU		N/A
*WY-0070	Cheyenne Prairie Generating Station	WY	8/23/2012	Diesel Emergency Generator (EP15)	ULSD	SO_2	ULSD	839	HP				Other case-by-case
*WY-0070	Cheyenne Prairie Generating Station	WY	8/23/2012	Diesel Fire Pump Engine (EP16)	ULSD	SO_2	ULSD	327	HP				BACT-PSD
AR-0140	Big River Steel LLC	AR	11/9/2016	Emergency generator SN-62	Diesel	SO_2	Good operating practices, limited hours of operation, compliance with NSPS Subpart IIII	625	HP	0.0015	% SULFUR FUEL		BACT-PSD
AR-0140	Big River Steel LLC	AR	11/9/2016	Emergency generators	Diesel	SO_2	Good operating practices, limited hours of operation, compliance with NSPS Subpart IIII	1500	KW	20	%		BACT-PSD
FL-0346	Lauderdale Plant	FL	1/8/2015	Emergency fire pump engine (300 HP)	USLD	SO_2	Good combustion practice and ULSD	29	MMBTU/hr	15	PPM SULFUR IN FUEL		BACT-PSD
FL-0346	Lauderdale Plant	FL	1/8/2015	Four 3100 kW black start emergency generators	ULSD	SO_2	ULSD required	2.32	MMBtu/hr (HHV) per engine	15	PPM SULFUR IN FUEL		BACT-PSD
FL-0354	Lauderdale Plant	FL	2/17/2016	Emergency fire pump engine, 300 HP	Diesel	SO_2	Limit in S in fuel	29	MMBTU/hr	0.0015	% S IN ULSD	Fuel record keeping	BACT-PSD
FL-0356	Okeechobee Clean Energy Center	FL	3/14/2016	One 422-hp emergency fire pump engine	ULSD	SO_2	Use of ULSD			0.0015	% S IN ULSD		BACT-PSD
FL-0356	Okeechobee Clean Energy Center	FL	3/14/2016	Three 3300-kW ULSD emergency generators	ULSD	SO_2	Use of ULSD			0.0015	% S IN ULSD		BACT-PSD
IN-0158	St. Joseph Energy Center, LLC	IN	8/15/2013	Emergency Diesel Generator	Diesel	SO_2	Ultra low sulfur distillate and usage limits	2012	HP	0.024	LB/H	3 hrs	BACT-PSD
IN-0158	St. Joseph Energy Center, LLC	IN	8/15/2013	Two (2) emergency diesel generators	Diesel	SO_2	Ultra low sulfur distillate and usage limits	1006	HP (each)	0.012	LB/H		BACT-PSD
IN-0158	St. Joseph Energy Center, LLC	IN	8/15/2013	Two (2) firewater pump diesel engines	Diesel	SO_2	Ultra low sulfur distillate and usage limits	371	BHP (each)	0.0015	% SUFLUR DIESEL FUEL		BACT-PSD
IN-0166	Indiana Gasification, LLC	IN	8/16/2013	Three (3) firewater pump engines	Diesel	SO_2	Use of low-S diesel and limited hours of non-emergency operation	575	HP (each)	15	PPM SULFUR		BACT-PSD
IN-0166	Indiana Gasification, LLC	IN	8/16/2013	Two (2) emergency generators	Diesel	SO_2	Use of low-S diesel and limited hours of non-emergency operation	1341	HP (each)	15	PPM SULFUR		BACT-PSD
IN-0185	MAG Pellet LLC	IN	8/12/2014	Diesel fire pump	Diesel	SO_2		300	HP	0.29	LB/MMBTU		BACT-PSD
IN-0234	Grain Processing Corporation	IN	2/25/2016	Emergency fire pump engine	Distillate oil	SO_2	Amount of diesel burned shall not exceed 1,128 gallons per 12 month period			0.0015	%	Sulfur content	BACT-PSD
LA-0288	Lake Charles Chemical Complex	LA	7/22/2016	Emergency Diesel Generators (EQT 629, 639, 838, 966, & 1264)		SO_2	Comply with 40 CFR 60 Subpart IIII; operate the engine in accordance with the engine manufacturer's instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage.	2682	HP	0.03	LB/HR	Hrly Max	BACT-PSD
MA-0039	Salem Harbor Station Redevelopment	MA	9/26/2014	Emergency Engine/Generator	ULSD	SO_2		7.4	MMBTU/hr	0.011	LB/H	1 hr block avg including SS	Other case-by-case
MA-0039	Salem Harbor Station Redevelopment	MA	9/26/2014	Fire Pump Engine	ULSD	SO_2		2.7	MMBTU/hr	0.004	LB/H	1 hr block avg	Other case-by-case
NJ-0081	PSEG Fossil LLC Sewaren Generating Station	NJ	8/22/2014	Emergency diesel fire pump	ULSD oil	SO_2	Use of ultra low sulfur fuel oil			0.002	LB/MMBTU		BACT-PSD
OH-0352	Oregon Clean Energy Center	OH	7/15/2013	Emergency fire pump engine	Diesel	SO_2		300	HP	0.003	LB/H		N/A
OH-0352	Oregon Clean Energy Center	OH	7/15/2013	Emergency generator	Diesel	SO_2		2250	KW	0.03	LB/H		N/A
PA-0278	Moxie Liberty LLC/Asylum Power Plant	PA	12/3/2012	Emergency Generator	Diesel	SO_2				0.005	G/B-HP-H		Other case-by-case
PA-0278	Moxie Liberty LLC/Asylum Power Plant	PA	12/3/2012	Fire Pump	Diesel	SO_2				0.005	G/B-HP-H		Other case-by-case
PA-0286	Moxie Energy LLC/Patriot Generation Plant	PA	3/27/2013	Emergency generator-engine	Diesel	SO_2	The permittee shall only use diesel fuel that is classified as ultra low sulfur non-highway diesel fuel (15 ppm sulfur maximum).			0.005	GM/B-HP-H	Expressed as SO_2	BACT-PSD
PA-0286	Moxie Energy LLC/Patriot Generation Plant	PA	3/27/2013	Fire Pump Engine - 460 BHP	Diesel	SO_2				0.005	G/HP-H	Expressed as SO_2	Other case-by-case
PR-0009	Energy Answers Arecibo Puerto Rico Renewable Energy Project	PR	10/14/2014	Emergency Diesel Fire Pump	ULSD Fuel Oil #2	SO_2				0.003	LB/H		BACT-PSD
PR-0009	Energy Answers Arecibo Puerto Rico Renewable Energy Project	PR	10/14/2014	Emergency Diesel Generator	ULSD Fuel oil # 2	SO_2				0.006	LB/H		BACT-PSD

Table 6.3
Engines, Generators, and Pumps RBLC Review - SO_2

RBLC ID	Facility Name	State	Date of Determination	Process	Primary Fuel	Pollutant	Control Method	Throughput	Units	Emissions Limit	Units	Avg Condition	Basis
SC-0113	Pyramax Ceramics, LLC	SC	5/9/2012	Emergency engine 1 thru 8	Diesel	SO_2	Low sulfur diesel. Maximum of 100 hours per year running time for maintenance and testing.	29	HP				BACT-PSD
SC-0113	Pyramax Ceramics, LLC	SC	5/9/2012	Emergency generators 1 thru 8	Diesel	SO_2	Use of low sulfur fuel diesel, sulfur content less than 0.0015 percent. Operating hours less than 100 hours per year for maintenance and testing.	757	HP				BACT-PSD
SC-0113	Pyramax Ceramics, LLC	SC	5/9/2012	Fire pump	Diesel	SO_2	Use of low sulfur fuel diesel, sulfur content less than 0.0015 percent. Operating hours less than 100 hours per year for maintenance and testing.	500	HP				BACT-PSD

Table 6.4
Engines, Generators, and Pumps RBLC Review - PM

RBLC ID	Facility Name	State	Date of Determination	Process	Primary Fuel	Pollutant	Control Method	Throughput	Units	Emissions Limit	Units	Avg Condition	Basis
*LA-0296	Lake Charles Chemical Complex LDPE Unit	LA	9/12/2016	Emergency Diesel Generators (EQTs 622, 671, 773, 850, 994, 995, 996, 1033, 1077, 1105, & 1202)	Diesel	PM (Total and LT) (10)	Compliance with 40 CFR 60 Subpart IIII; operating the engine in accordance with the engine manufacturer's instructions and/or written procedures (consistent with safe operation) designed to maximize combustion efficiency and minimize fuel usage.	2682	HP	0.88	LB/HR	Hourly maximum	BACT-PSD
*LA-0296	Lake Charles Chemical Complex LDPE Unit	LA	9/12/2016	Emergency Diesel Generators (EQTs 622, 671, 773, 850, 994, 995, 996, 1033, 1077, 1105, & 1202)	Diesel	PM (Total and LT) (2.5)	Compliance with 40 CFR 60 Subpart IIII; operating the engine in accordance with the engine manufacturer's instructions and/or written procedures (consistent with safe operation) designed to maximize combustion efficiency and minimize fuel usage.	2682	HP	0.88	LB/HR	Hourly maximum	BACT-PSD
*LA-0305	Lake Charles Methanol Facility	LA	3/7/2017	Diesel Engines (Emergency)	Diesel	PM (Total and LT) (10)	Complying with 40 CFR 60 Subpart IIII	4023	HP				BACT-PSD
*LA-0305	Lake Charles Methanol Facility	LA	3/7/2017	Diesel Engines (Emergency)	Diesel	PM (Total and LT) (2.5)	Complying with 40 CFR 60 Subpart IIII	4023	HP				BACT-PSD
*LA-0307	Magnolia LNG Facility	LA	3/8/2017	Diesel Engines	Diesel	PM (Total and LT) (10)	good combustion practices, Use ultra low sulfur diesel, and comply with 40 CFR 60 Subpart IIII						BACT-PSD
*LA-0307	Magnolia LNG Facility	LA	3/8/2017	Diesel Engines	Diesel	PM (Total and LT) (2.5)	good combustion practices, Use ultra low sulfur diesel, and comply with 40 CFR 60 Subpart IIII						BACT-PSD
*LA-0309	Benteler Steel Tube Facility	LA	3/9/2017	Emergency Generator Engines	Diesel	PM (Total and LT) (10)	Complying with 40 CFR 60 Subpart IIII	2922	HP (each)	0.2	G/KW-HR		BACT-PSD
*LA-0309	Benteler Steel Tube Facility	LA	3/9/2017	Emergency Generator Engines	Diesel	PM (Total and LT) (2.5)	Complying with 40 CFR 60 Subpart IIII	2922	HP (each)	0.2	G/KW-HR		BACT-PSD
*LA-0309	Benteler Steel Tube Facility	LA	3/9/2017	Firewater Pump Engines	Diesel	PM (Total and LT) (10)	Complying with 40 CFR 60 Subpart IIII	288	HP (each)	0.15	G/BHP-HR		BACT-PSD
*LA-0309	Benteler Steel Tube Facility	LA	3/9/2017	Firewater Pump Engines	Diesel	PM (Total and LT) (2.5)	Complying with 40 CFR 60 Subpart IIII	288	HP (each)	0.15	G/BHP-HR		BACT-PSD
*LA-0315	G2G Plant	LA	3/13/2017	Emergency Diesel Generator 1	Diesel	PM (Total and LT) (10)	Proper design and operation; use of ultra-low sulfur diesel	5364	HP	1.76	LB/HR	Hourly maximum	BACT-PSD
*LA-0315	G2G Plant	LA	3/13/2017	Emergency Diesel Generator 1	Diesel	PM (Total and LT) (2.5)	Proper burner design and operation	5364	HP	1.76	LB/HR	Hourly maximum	BACT-PSD
*LA-0315	G2G Plant	LA	3/13/2017	Emergency Diesel Generator 2	Diesel	PM (Total and LT) (10)	Proper design and operation; use of ultra-low sulfur diesel	5364	HP	1.76	LB/HR	Hourly maximum	BACT-PSD
*LA-0315	G2G Plant	LA	3/13/2017	Emergency Diesel Generator 2	Diesel	PM (Total and LT) (2.5)	Proper design and operation; use of ultra-low sulfur diesel	5364	HP	1.76	LB/HR	Hourly maximum	BACT-PSD
*LA-0315	G2G Plant	LA	3/13/2017	Fire Pump Diesel Engine 1	Diesel	PM (Total and LT) (10)	Proper design and operation; use of ultra-low sulfur diesel	751	HP	0.25	LB/HR	Hourly maximum	BACT-PSD
*LA-0315	G2G Plant	LA	3/13/2017	Fire Pump Diesel Engine 1	Diesel	PM (Total and LT) (2.5)	Proper design and operation; use of ultra-low sulfur diesel	751	HP	0.25	LB/HR	Hourly maximum	BACT-PSD
*LA-0315	G2G Plant	LA	3/13/2017	Fire Pump Diesel Engine 2	Diesel	PM (Total and LT) (10)	Proper design and operation; use of ultra-low sulfur diesel	751	HP	0.25	LB/HR	Hourly maximum	BACT-PSD
*LA-0315	G2G Plant	LA	3/13/2017	Fire Pump Diesel Engine 2	Diesel	PM (Total and LT) (2.5)	Proper design and operation; use of ultra-low sulfur diesel	751	HP	0.25	LB/HR	Hourly maximum	BACT-PSD
*LA-0316	Cameron LNG Facility	LA	3/14/2017	emergency generator engines (6 units)	diesel	PM (Total and LT) (10)	Complying with 40 CFR 60 Subpart IIII	3353	HP				BACT-PSD
*LA-0316	Cameron LNG Facility	LA	3/14/2017	emergency generator engines (6 units)	diesel	PM (Total and LT) (2.5)	Complying with 40 CFR 60 Subpart IIII	3353	HP				BACT-PSD
*LA-0316	Cameron LNG Facility	LA	3/14/2017	firewater pump engines (8 units)	diesel	PM (Total and LT) (10)	Complying with 40 CFR 60 Subpart IIII	460	HP				BACT-PSD
*LA-0316	Cameron LNG Facility	LA	3/14/2017	firewater pump engines (8 units)	diesel	PM (Total and LT) (2.5)	Complying with 40 CFR 60 Subpart IIII	460	HP				BACT-PSD
*LA-0317	Methanex - Geismar Methanol Plant	LA	3/15/2017	Emergency Generator Engines (4 units)	Diesel	PM (Total and LT) (10)	complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ						BACT-PSD
*LA-0317	Methanex - Geismar Methanol Plant	LA	3/15/2017	Emergency Generator Engines (4 units)	Diesel	PM (Total and LT) (2.5)	complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ						BACT-PSD
*LA-0317	Methanex - Geismar Methanol Plant	LA	3/15/2017	Firewater pump Engines (4 units)	diesel	PM (Total and LT) (10)	complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	896	HP (each)				BACT-PSD
*LA-0317	Methanex - Geismar Methanol Plant	LA	3/15/2017	Firewater pump Engines (4 units)	diesel	PM (Total and LT) (2.5)	complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	896	HP (each)				BACT-PSD
*MD-0042	Wildcat Point Generation Facility	MD	7/31/2015	Emergency Diesel Engine for Fire Water Pump	ULSD	PM (Filterable)	Exclusive use of ULSD fuel, good combustion practices, limited hours of operation, and designed to achieve emission limits	477	HP	0.15	G/HP-H		BACT-PSD
*MD-0042	Wildcat Point Generation Facility	MD	7/31/2015	Emergency Diesel Engine for Fire Water Pump	ULSD	PM (Total and LT) (10)	Exclusive use of ULSD fuel, good combustion practices, limited hours of operation, and designed to achieve emission limits	477	HP	0.15	G/HP-H		BACT-PSD
*MD-0042	Wildcat Point Generation Facility	MD	7/31/2015	Emergency Diesel Engine for Fire Water Pump	ULSD	PM (Total and LT) (2.5)	Exclusive use of ULSD fuel, good combustion practices, limited hours of operation, and designed to achieve emission limits	477	HP	0.15	G/HP-H		BACT-PSD
*MD-0042	Wildcat Point Generation Facility	MD	7/31/2015	Emergency Generator 1	ULSD	PM (Filterable)	Exclusive use of ULSD fuel, good combustion practices, limited hours of operation, and designed to achieve emission limits	2250	KW	0.15	G/HP-H		BACT-PSD
*MD-0042	Wildcat Point Generation Facility	MD	7/31/2015	Emergency Generator 1	ULSD	PM (Total and LT) (10)	Exclusive use of ULSD fuel, good combustion practices, limited hours of operation, and designed to achieve emission limits	2250	KW	0.15	G/HP-H		BACT-PSD
*MD-0042	Wildcat Point Generation Facility	MD	7/31/2015	Emergency Generator 1	ULSD	PM (Total and LT) (2.5)	Exclusive use of ULSD fuel, good combustion practices, limited hours of operation, and designed to achieve emission limits	2250	KW	0.15	G/HP-H		BACT-PSD
*OK-0156	Northstar AGRI IND Enid	OK	6/19/2014	Fire Pump Engine	Diesel	PM (Total and LT) (10)		550	HP	0.2	GM/HP-HR		BACT-PSD

Table 6.4
Engines, Generators, and Pumps RBLC Review - PM

RBLC ID	Facility Name	State	Date of Determination	Process	Primary Fuel	Pollutant	Control Method	Throughput	Units	Emissions Limit	Units	Avg Condition	Basis
*OK-0156	Northstar AGRI IND Enid	OK	6/19/2014	Fire Pump Engine	Diesel	PM (Total and LT) (10)		550	HP	0.2	GM/HP-HR		BACT-PSD
*OK-0156	Northstar AGRI IND Enid	OK	6/19/2014	Fire Pump Engine	Diesel	PM (Total and LT) (2.5)		550	HP	0.2	GM/HP-HR		BACT-PSD
*OK-0156	Northstar AGRI IND Enid	OK	6/19/2014	Fire Pump Engine	Diesel	PM (Total and LT) (2.5)		550	HP	0.2	GM/HP-HR		BACT-PSD
*VA-0325	Greensville Power Station	VA	9/16/2016	Diesel-Fired Emergency Generator 3000 kW (1)	Diesel fuel	PM (Total and LT) (10)	ULSD/Fuel (15 ppm max)			0.4	G/KW	PER HR	N/A
*VA-0325	Greensville Power Station	VA	9/16/2016	Diesel-Fired Emergency Generator 3000 kW (1)	Diesel fuel	PM (Total and LT) (2.5)	ULSD/Fuel (15 ppm max)			0.4	G/KR	PER HR	N/A
*VA-0325	Greensville Power Station	VA	9/16/2016	Diesel-Fired Water Pump 376 bph (1)	Diesel fuel	PM (Total and LT) (10)	ULSD/Fuel (15 ppm max)			0.3	G/HP-H	PER HR	N/A
*VA-0325	Greensville Power Station	VA	9/16/2016	Diesel-Fired Water Pump 376 bph (1)	Diesel fuel	PM (Total and LT) (2.5)	ULSD/Fuel (15 ppm max)			0.3	G/HP-H	HR	N/A
*WV-0025	Moundsville Combined Cycle Power Plant	WV	1/5/2015	Emergency Generator	Diesel	PM (Filterable and LT) (2.5)		2015.7	HP				BACT-PSD
*WV-0025	Moundsville Combined Cycle Power Plant	WV	1/5/2015	Fire Pump Engine	Diesel	PM (Filterable and LT) (2.5)		251	HP				BACT-PSD
AK-0076	Point Thomson Production Facility	AK	8/23/2012	Combustion of Diesel by ICEs	ULSD	PM (Total and LT) (2.5)		1750	kW	0.2	G/KW-H		BACT-PSD
AK-0081	Point Thomson Production Facility	AK	8/30/2013	Combustion engine	ULSD	PM (Total and LT) (2.5)	Good operation and combustion practices	610	HP	0.15	G/KW-H		Other case-by-case
AK-0081	Point Thomson Production Facility	AK	8/30/2013	Combustion Engine	ULSD	PM (Total and LT) (2.5)	Good combustion and operating practices.	493	HP	0.2	G/KW-H		Other case-by-case
AK-0081	Point Thomson Production Facility	AK	8/30/2013	Combustion Engines	ULSD	PM (Total and LT) (2.5)	Good operation and combustion practices	610	HP	0.15	G/KW-H		Other case-by-case
AK-0081	Point Thomson Production Facility	AK	8/30/2013	Combustion Engines	ULSD	PM (Total and LT) (2.5)	Good combustion and operating practices.	493	HP	0.2	G/KW-H		Other case-by-case
AK-0082	Point Thomson Production Facility	AK	1/28/2015	Agitator Generator Engine	ULSD	PM (Filterable and LT) (10)		98	HP	0.3	GRAMS/HP-H		BACT-PSD
AK-0082	Point Thomson Production Facility	AK	1/28/2015	Agitator Generator Engine	ULSD	PM (Filterable and LT) (2.5)		98	HP	0.3	GRAMS/HP-H		BACT-PSD
AK-0082	Point Thomson Production Facility	AK	1/28/2015	Airstrip Generator Engine	ULSD	PM (Filterable and LT) (10)		490	HP	0.15	GRAMS/HP-H		BACT-PSD
AK-0082	Point Thomson Production Facility	AK	1/28/2015	Airstrip Generator Engine	ULSD	PM (Filterable and LT) (2.5)		490	HP	0.15	GRAMS/HP-H		BACT-PSD
AK-0082	Point Thomson Production Facility	AK	1/28/2015	Bulk Tank Generator Engines	ULSD	PM (Filterable and LT) (10)		891	HP	0.15	GRAMS/HP-H		BACT-PSD
AK-0082	Point Thomson Production Facility	AK	1/28/2015	Bulk Tank Generator Engines	ULSD	PM (Filterable and LT) (2.5)		891	HP	0.15	GRAMS/HP-H		BACT-PSD
AK-0082	Point Thomson Production Facility	AK	1/28/2015	Fine Water Pumps	ULSD	PM (Filterable and LT) (10)		610	HP	0.15	GRAMS/HP-H		BACT-PSD
AK-0082	Point Thomson Production Facility	AK	1/28/2015	Fine Water Pumps	ULSD	PM (Filterable and LT) (2.5)		610	HP	0.15	GRAMS/HP-H		BACT-PSD
AK-0083	Kenai Nitrogen Operations	AK	1/29/2015	Diesel Fired Well Pump	Diesel	PM (Total and LT) (10)	Limited Operation of 168 hr/yr.	2.7	MMBTU/HR	0.31	LB/MMBTU		BACT-PSD
AK-0083	Kenai Nitrogen Operations	AK	1/29/2015	Diesel Fired Well Pump	Diesel	PM (Total and LT) (2.5)	Limited Operation of 168 hr/yr.	2.7	MMBTU/HR	0.31	LB/MMBTU		BACT-PSD
AK-0083	Kenai Nitrogen Operations	AK	1/29/2015	Diesel Fired Well Pump	Diesel	PM (Total) (10)	Limited Operation of 168 hr/yr.	2.7	MMBTU/HR	0.31	LB/MMBTU		BACT-PSD
AR-0140	Big River Steel LLC	AR	11/9/2016	Emergency Generator SN-62	Diesel	PM (Filterable)	Good operating practices, limited hours of operation, compliance with NSPS Subpart IIII	625	HP	0.02	G/KW-H		BACT-PSD
AR-0140	Big River Steel LLC	AR	11/9/2016	Emergency Generator SN-62	Diesel	PM (Total and LT) (10)	Good operating practices, limited hours of operation, compliance with NSPS Subpart IIII	625	HP	0.02	G/KW-H		BACT-PSD
AR-0140	Big River Steel LLC	AR	11/9/2016	Emergency Generator SN-62	Diesel	PM (Total and LT) (2.5)	Good operating practices, limited hours of operation, compliance with NSPS Subpart IIII	625	HP	0.02	GR/KW-H		BACT-PSD
AR-0140	Big River Steel LLC	AR	11/9/2016	Emergency Generators	Diesel	PM (Filterable)	Good operating practices, limited hours of operation, compliance with NSPS Subpart IIII	1500	KW	0.02	G/KW-H		BACT-PSD
AR-0140	Big River Steel LLC	AR	11/9/2016	Emergency Generators	Diesel	PM (Total and LT) (10)	Good operating practices, limited hours of operation, compliance with NSPS Subpart IIII	1500	KW	0.04	G/KW-H		BACT-PSD
AR-0140	Big River Steel LLC	AR	11/9/2016	Emergency Generators	Diesel	PM (Total and LT) (2.5)	Good operating practices, limited hours of operation, compliance with NSPS Subpart IIII	1500	KW	0.04	G/KW-H		BACT-PSD
FL-0346	Lauderdale Plant	FL	1/8/2015	Emergency fire pump engine (300 HP)	USLD	PM (Total) (10)	Good combustion practice	29	MMBTU/HR	0.2	GRAM PER HP-HR		BACT-PSD
FL-0346	Lauderdale Plant	FL	1/8/2015	Four 3100 kW black start emergency generators	ULSD	PM (Total) (10)	Good combustion practice	2.32	MMBtu/hr (HHV) per engine	0.2	GRAMS PER KW-HR		BACT-PSD
FL-0346	Lauderdale Plant	FL	1/8/2015	Four 3100 kW black start emergency generators	ULSD	PM (Total) (10)	Good combustion practice	2.32	MMBtu/hr (HHV) per engine	0.2	GRAMS PER KW-HR		BACT-PSD
FL-0354	Lauderdale Plant	FL	2/17/2016	Emergency fire pump engine, 300 HP	Diesel	PM (Total) (10)	Low-emitting fuel and certified engine	29	MMBTU/HR	0.2	G / KWH		BACT-PSD
FL-0356	Okeechobee Clean Energy Center	FL	3/14/2016	One 422-HP emergency fire pump engine	ULSD	PM (Total) (10)	Use of clean fuel			0.2	G / KW-HR		BACT-PSD
FL-0356	Okeechobee Clean Energy Center	FL	3/14/2016	Three 3300-kW ULSD emergency generators	ULSD	PM (Total) (10)	Use of clean fuel			0.2	G / KW-HR		BACT-PSD
IA-0105	Iowa Fertilizer Company	IA	11/1/2012	Emergency Generator	diesel fuel	PM (Total and LT) (10)	good combustion practices	142	GAL/HR	0.2	G/KW-H	Average of 3 stack test runs	BACT-PSD

Table 6.4
Engines, Generators, and Pumps RBLC Review - PM

RBLC ID	Facility Name	State	Date of Determination	Process	Primary Fuel	Pollutant	Control Method	Throughput	Units	Emissions Limit	Units	Avg Condition	Basis
IA-0105	Iowa Fertilizer Company	IA	11/1/2012	Emergency Generator	diesel fuel	PM (Total and LT) (2.5)	good combustion practices	142	GAL/HR	0.2	G/KW-H	Average of 3 stack test runs	BACT-PSD
IA-0105	Iowa Fertilizer Company	IA	11/1/2012	Emergency Generator	diesel fuel	PM (Total) (10)	good combustion practices	142	GAL/HR	0.2	G/KW-H	Average of 3 stack test runs	BACT-PSD
IA-0105	Iowa Fertilizer Company	IA	11/1/2012	Fire Pump	diesel fuel	PM (Total and LT) (10)	good combustion practices	14	GAL/HR	0.2	G/KW-H	Average of 3 stack test runs	BACT-PSD
IA-0105	Iowa Fertilizer Company	IA	11/1/2012	Fire Pump	diesel fuel	PM (Total and LT) (2.5)	good combustion practices	14	GAL/HR	0.2	G/KW-H	Average of 3 stack test runs	BACT-PSD
IA-0105	Iowa Fertilizer Company	IA	11/1/2012	Fire Pump	diesel fuel	PM (Total) (10)	good combustion practices	14	GAL/HR	0.2	G/KW-H	Average of 3 stack test runs	BACT-PSD
IA-0106	CF Industries Nitrogen, LLC - Port Neal Nitrogen Complex	IA	7/16/2013	Emergency Generators	diesel fuel	PM (Total and LT) (10)	good combustion practices	180	GAL/HR	0.2	G/KW-H	Average of 3 stack test runs	BACT-PSD
IA-0106	CF Industries Nitrogen, LLC - Port Neal Nitrogen Complex	IA	7/16/2013	Emergency Generators	diesel fuel	PM (Total and LT) (2.5)	good combustion practices	180	GAL/HR	0.2	G/KW-H	Average of 3 stack test runs	BACT-PSD
IA-0106	CF Industries Nitrogen, LLC - Port Neal Nitrogen Complex	IA	7/16/2013	Emergency Generators	diesel fuel	PM (Total) (10)	good combustion practices	180	GAL/HR	0.2	G/KW-H	Average of 3 stack test runs	BACT-PSD
IL-0114	Cronus Chemicals, LLC	IL	12/24/2014	Emergency Generator	distillate fuel oil	PM (Filterable)	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7.	3755	HP	0.1	G/KW-H		BACT-PSD
IL-0114	Cronus Chemicals, LLC	IL	12/24/2014	Emergency Generator	distillate fuel oil	PM (Total and LT) (10)	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7.	3755	HP	0.1	G/KW-H		BACT-PSD
IL-0114	Cronus Chemicals, LLC	IL	12/24/2014	Emergency Generator	distillate fuel oil	PM (Total and LT) (2.5)	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7.	3755	HP	0.1	G/KW-H		BACT-PSD
IL-0114	Cronus Chemicals, LLC	IL	12/24/2014	Firewater Pump Engine	distillate fuel oil	PM (Filterable)	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7.	373	HP	0.1	G/KW-H		BACT-PSD
IL-0114	Cronus Chemicals, LLC	IL	12/24/2014	Firewater Pump Engine	distillate fuel oil	PM (Total and LT) (10)	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7.	373	HP	0.1	G/KW-H		BACT-PSD
IL-0114	Cronus Chemicals, LLC	IL	12/24/2014	Firewater Pump Engine	distillate fuel oil	PM (Total and LT) (2.5)	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7.	373	HP	0.1	G/KW-H		BACT-PSD
IN-0158	St. Joseph Energy Center, LLC	IN	8/15/2013	Emergency Diesel Generator	Diesel	PM (Filterable and LT) (10)	Combustion design controls and usage limits	2012	HP	0.15	G/HP-H	3 HRs	BACT-PSD
IN-0158	St. Joseph Energy Center, LLC	IN	8/15/2013	Emergency Diesel Generator	Diesel	PM (Filterable and LT) (2.5)	Combustion design controls and usage limits	2012	HP	0.15	G/HP-H	3 HRs	BACT-PSD
IN-0158	St. Joseph Energy Center, LLC	IN	8/15/2013	Emergency Diesel Generator	Diesel	PM (Filterable)	Combustion design controls and usage limits	2012	HP	0.15	G/HP-H	3 HRs	BACT-PSD
IN-0158	St. Joseph Energy Center, LLC	IN	8/15/2013	Two (2) Emergency Diesel Generators	Diesel	PM (Filterable and LT) (10)	Combustion design controls and usage limits	1006	HP each	0.15	G/HP-H	3 HRs	BACT-PSD
IN-0158	St. Joseph Energy Center, LLC	IN	8/15/2013	Two (2) Emergency Diesel Generators	Diesel	PM (Filterable and LT) (2.5)	Combustion design controls and usage limits	1006	HP each	0.15	G/HP-H	3 HRs	BACT-PSD
IN-0158	St. Joseph Energy Center, LLC	IN	8/15/2013	Two (2) Emergency Diesel Generators	Diesel	PM (Filterable)	Combustion design controls and usage limits	1006	HP each	0.15	G/HP-H		BACT-PSD
IN-0158	St. Joseph Energy Center, LLC	IN	8/15/2013	Two (2) Firewater Pump Diesel Engines	Diesel	PM (Filterable and LT) (10)	Combustion design controls and usage limits	371	BHP, each	0.15	G/HP-H		BACT-PSD
IN-0158	St. Joseph Energy Center, LLC	IN	8/15/2013	Two (2) Firewater Pump Diesel Engines	Diesel	PM (Filterable and LT) (2.5)	Combustion design controls and usage limits	371	BHP, each	0.15	G/HP-H	3 HRs	BACT-PSD
IN-0158	St. Joseph Energy Center, LLC	IN	8/15/2013	Two (2) Firewater Pump Diesel Engines	Diesel	PM (Filterable)	Combustion design controls and usage limits	371	BHP, each	0.15	G/HP-H		BACT-PSD
IN-0166	Indiana Gasification, LLC	IN	8/16/2013	Three (3) Firewater Pump Engines	Diesel	PM (Filterable)	Use of low-S diesel and limited hours of non-emergency operation	575	HP, each	15	PPM SULFUR		BACT-PSD
IN-0166	Indiana Gasification, LLC	IN	8/16/2013	Three (3) Firewater Pump Engines	Diesel	PM (Total and LT) (10)	Use of low-S diesel and limited hours of non-emergency operation	575	HP, each	15	PPM SULFUR		BACT-PSD
IN-0166	Indiana Gasification, LLC	IN	8/16/2013	Three (3) Firewater Pump Engines	Diesel	PM (Total and LT) (2.5)	Use of low-S diesel and limited hours of non-emergency operation	575	HP, each	15	PPM SULFUR		BACT-PSD
IN-0166	Indiana Gasification, LLC	IN	8/16/2013	Two (2) Emergency Generators	Diesel	PM (Filterable)	Use of low-S diesel and limited hours of non-emergency operation	1341	HP, each	15	PPM SULFUR		BACT-PSD
IN-0166	Indiana Gasification, LLC	IN	8/16/2013	Two (2) Emergency Generators	Diesel	PM (Total and LT) (10)	Use of low-S diesel and limited hours of non-emergency operation	1341	HP, each	15	PPM SULFUR		BACT-PSD
IN-0166	Indiana Gasification, LLC	IN	8/16/2013	Two (2) Emergency Generators	Diesel	PM (Total and LT) (2.5)	Use of low-S diesel	1341	HP, each	15	PPM SULFUR		BACT-PSD
IN-0173	Midwest Fertilizer Corporation	IN	7/17/2014	Diesel Fired Emergency Generator	No. 2, Diesel	PM (Filterable)	Good combustion practices	3600	BHP	0.15	G/BHP-H	3-HR average	BACT-PSD
IN-0173	Midwest Fertilizer Corporation	IN	7/17/2014	Diesel Fired Emergency Generator	No. 2, Diesel	PM (Total and LT) (10)	Good combustion practices	3600	BHP	0.15	G/BHP-H	3-HR average	BACT-PSD
IN-0173	Midwest Fertilizer Corporation	IN	7/17/2014	Diesel Fired Emergency Generator	No. 2, Diesel	PM (Total and LT) (2.5)	Good combustion practices	3600	BHP	0.15	G/BHP-H	3-HR average	BACT-PSD

Table 6.4
Engines, Generators, and Pumps RBLC Review - PM

RBLC ID	Facility Name	State	Date of Determination	Process	Primary Fuel	Pollutant	Control Method	Throughput	Units	Emissions Limit	Units	Avg Condition	Basis
IN-0173	Midwest Fertilizer Corporation	IN	7/17/2014	Fire Pump	0	PM (Filterable)	Good combustion practices	500	HP	0.15	G/BHP-H	3-HR average	BACT-PSD
IN-0173	Midwest Fertilizer Corporation	IN	7/17/2014	Fire Pump	0	PM (Total and LT) (10)	Good combustion practices	500	HP	0.15	G/BHP-H	3-HR average	BACT-PSD
IN-0173	Midwest Fertilizer Corporation	IN	7/17/2014	Fire Pump	0	PM (Total and LT) (2.5)	Good combustion practices	500	HP	0.15	G/BHP-H	3-HR average	BACT-PSD
IN-0179	Ohio Valley Resources, LLC	IN	8/12/2014	Diesel Fired Emergency Generator	No. 2 fuel oil	PM (Filterable)	Good combustion practices	4690	B-HP	0.15	G/B-HP-H	3-HR average	BACT-PSD
IN-0179	Ohio Valley Resources, LLC	IN	8/12/2014	Diesel Fired Emergency Generator	No. 2 fuel oil	PM (Total and LT) (10)	Good combustion practices	4690	B-HP	0.15	G/B-HP-H	3-HR average	BACT-PSD
IN-0179	Ohio Valley Resources, LLC	IN	8/12/2014	Diesel Fired Emergency Generator	No. 2 fuel oil	PM (Total and LT) (2.5)	Good combustion practices	4690	B-HP	0.15	LB/B-HP-H	3-HR average	BACT-PSD
IN-0179	Ohio Valley Resources, LLC	IN	8/12/2014	Diesel-Fired Emergency Water Pump	No. 2 fuel oil	PM (Filterable)	Good combustion practices	481	BHP	0.15	G/B-HP-H	3-HR average	BACT-PSD
IN-0179	Ohio Valley Resources, LLC	IN	8/12/2014	Diesel-Fired Emergency Water Pump	No. 2 fuel oil	PM (Total and LT) (10)	Good combustion practices	481	BHP	0.15	G/B-HP-H	3-HR average	BACT-PSD
IN-0179	Ohio Valley Resources, LLC	IN	8/12/2014	Diesel-Fired Emergency Water Pump	No. 2 fuel oil	PM (Total and LT) (2.5)	Good combustion practices	481	BHP	0.15	G/B-HP-H	3-HR average	BACT-PSD
IN-0180	Midwest Fertilizer Corporation	IN	8/12/2014	Diesel Fired Emergency Generator	No. 2, Diesel	PM (Filterable)	Good combustion practices	3600	BHP	0.15	G/B-HP-H	3-HR average	BACT-PSD
IN-0180	Midwest Fertilizer Corporation	IN	8/12/2014	Diesel Fired Emergency Generator	No. 2, Diesel	PM (Total and LT) (10)	Good combustion practices	3600	BHP	0.15	G/B-HP-H	3-HR average	BACT-PSD
IN-0180	Midwest Fertilizer Corporation	IN	8/12/2014	Diesel Fired Emergency Generator	No. 2, Diesel	PM (Total and LT) (2.5)	Good combustion practices	3600	BHP	0.15	G/B-HP-H	3-HR average	BACT-PSD
IN-0180	Midwest Fertilizer Corporation	IN	8/12/2014	Fire Pump		PM (Filterable)	Good combustion practices	500	HP	0.15	G/B-HP-H	3-HR average	BACT-PSD
IN-0180	Midwest Fertilizer Corporation	IN	8/12/2014	Fire Pump		PM (Total and LT) (10)	Good combustion practices	500	HP	0.15	G/B-HP-H	3-HR average	BACT-PSD
IN-0180	Midwest Fertilizer Corporation	IN	8/12/2014	Fire Pump		PM (Total and LT) (2.5)	Good combustion practices	500	HP	0.15	G/B-HP-H	3-HR average	BACT-PSD
IN-0185	MAG Pellet LLC	IN	8/12/2014	Diesel Fire Pump	Diesel	PM (Filterable and LT) (10)		300	HP	0.15	G/HP-H		BACT-PSD
IN-0185	MAG Pellet LLC	IN	8/12/2014	Diesel Fire Pump	Diesel	PM (Filterable and LT) (2.5)		300	HP	0.15	G/HP-H		BACT-PSD
IN-0185	MAG Pellet LLC	IN	8/12/2014	Diesel Fire Pump	Diesel	PM (Filterable)		300	HP	0.15	G/HP-H		BACT-PSD
IN-0202	IPL Eagle Valley Generating Station	IN	5/11/2015	Emergency Fire Pump EU-6	Diesel	PM (Total and LT) (2.5)	Good combustion practices and fuel specification	500	HP	0.0072	LB/MMBTU	3-HR average	Other case-by-case
IN-0202	IPL Eagle Valley Generating Station	IN	5/11/2015	Emergency Fire Pump EU-6	Diesel	PM (Total) (10)	Good combustion practices and fuel specification	500	HP	0.0072	LB/MMBTU	3-HR average	Other case-by-case
IN-0234	Grain Processing Corporation	IN	2/25/2016	Emergency Fire Pump Engine	Distillate oil	PM (Filterable)	Good combustion practices			0.16	G/HP-H		BACT-PSD
IN-0234	Grain Processing Corporation	IN	2/25/2016	Emergency Fire Pump Engine	Distillate oil	PM (Total and LT) (10)	Good combustion practices			0.16	G/HP-H		BACT-PSD
LA-0288	Lake Charles Chemical Complex	LA	7/22/2016	Emergency Diesel Generators (EQT 629, 639, 838, 966, & 1264)		PM (Total and LT) (10)	Comply with 40 CFR 60 Subpart IIII; operate the engine in accordance with the engine manufacturers instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage.	2682	HP	0.88	LB/HR	Hourly maximum	BACT-PSD
LA-0288	Lake Charles Chemical Complex	LA	7/22/2016	Emergency Diesel Generators (EQT 629, 639, 838, 966, & 1264)		PM (Total and LT) (2.5)	Comply with 40 CFR 60 Subpart IIII; operate the engine in accordance with the engine manufacturers instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage.	2682	HP	0.88	LB/HR	Hourly maximum	BACT-PSD
LA-0292	Holbrook Compressor Station	LA	8/4/2016	Emergency Generators No. 1 & No. 2	Diesel	PM (Total and LT) (2.5)	Use of a certified engine, low sulfur diesel, and limiting non-emergency use to no more than 100 hours per year	1341	HP	0.44	LB/HR	Hourly maximum	BACT-PSD
MA-0039	Salem Harbor Station Redevelopment	MA	9/26/2014	Emergency Engine/Generator	ULSD	PM (Total and LT) (10)		7.4	MMBTU/H	0.15	GM/BHP-H	1 HR block average	BACT-PSD
MA-0039	Salem Harbor Station Redevelopment	MA	9/26/2014	Emergency Engine/Generator	ULSD	PM (Total and LT) (2.5)		7.4	MMBTU/H	0.15	GM/BHP-H	1 HR block average	BACT-PSD
MA-0039	Salem Harbor Station Redevelopment	MA	9/26/2014	Fire Pump Engine	ULSD	PM (Total and LT) (10)		2.7	MMBTU/H	0.15	GM/BHP-H	1 HR block average	BACT-PSD
MA-0039	Salem Harbor Station Redevelopment	MA	9/26/2014	Fire Pump Engine	ULSD	PM (Total and LT) (2.5)		2.7	MMBTU/H	0.15	GM/BHP-H	1 HR block average	BACT-PSD
MD-0044	Cove Point LNG Terminal	MD	8/25/2015	5 Emergency Fire Water Pump Engines	ULSD	PM (Filterable)	Exclusive use of ULSD fuel, good combustion practices and designed to achieve emission limits	350	HP	0.15	G/BHP-H	0	BACT-PSD
MD-0044	Cove Point LNG Terminal	MD	8/25/2015	5 Emergency Fire Water Pump Engines	ULSD	PM (Total and LT) (10)	Exclusive use of ULSD fuel, good combustion practices and designed to achieve emission limits	350	HP	0.17	G/BHP-H	0	BACT-PSD
MD-0044	Cove Point LNG Terminal	MD	8/25/2015	5 Emergency Fire Water Pump Engines	ULSD	PM (Total and LT) (2.5)	Exclusive use of ULSD fuel, good combustion practices and designed to achieve emission limits	350	HP	0.17	G/BHP-H	0	BACT-PSD
MD-0044	Cove Point LNG Terminal	MD	8/25/2015	Emergency Generator	ULSD	PM (Filterable)	Exclusive use of ULSD fuel, good combustion practices and designed to achieve emission limits	1550	HP	0.15	G/HP-H	0	BACT-PSD
MD-0044	Cove Point LNG Terminal	MD	8/25/2015	Emergency Generator	ULSD	PM (Total and LT) (10)	Exclusive use of ULSD fuel, good combustion practices and designed to achieve emission limits	1550	HP	0.17	G/HP-H	0	BACT-PSD

Table 6.4
Engines, Generators, and Pumps RBLC Review - PM

RBLC ID	Facility Name	State	Date of Determination	Process	Primary Fuel	Pollutant	Control Method	Throughput	Units	Emissions Limit	Units	Avg Condition	Basis
MD-0044	Cove Point LNG Terminal	MD	8/25/2015	Emergency Generator	ULSD	PM (Total and LT) (2.5)	Exclusive use of ULSD fuel, good combustion practices and designed to achieve emission limits	1550	HP	0.17	G/HP-H	0	BACT-PSD
MD-0046	Keys Energy Center	MD	12/23/2015	Diesel-Fired Auxiliary (emergency) Engines (two)	ULSD	PM (Filterable)	Use of ultra low sulfur diesel and good combustion practices	1500	KW	0.2	G/KW-H	0	BACT-PSD
MD-0046	Keys Energy Center	MD	12/23/2015	Diesel-Fired Auxiliary (emergency) Engines (two)	ULSD	PM (Total and LT) (10)	Use of ultra low sulfur diesel and good combustion practices	1500	KW	0.18	G/HP-H	0	BACT-PSD
MD-0046	Keys Energy Center	MD	12/23/2015	Diesel-Fired Fire Pump Engine	ULSD	PM (Filterable)	Exclusive use of ultra low sulfur diesel fuel and good combustion practices	300	HP	0.2	G/KW-H	0	BACT-PSD
MD-0046	Keys Energy Center	MD	12/23/2015	Diesel-Fired Fire Pump Engine	ULSD	PM (Total and LT) (10)	Exclusive use of ultra low sulfur diesel fuel and good combustion practices	300	HP	0.18	G/HP-H	0	BACT-PSD
MI-0406	Renaissance Power LLC	MI	3/19/2014	FG-EMGEN7-8; Two (2) 1,000kW diesel-fueled emergency reciprocating internal combustion engines	Diesel	PM (Filterable)	Good combustion practices.	1000	kW	0.15	G/B-HP-H	Test protocol; each unit	BACT-PSD
MI-0406	Renaissance Power LLC	MI	3/19/2014	FG-EMGEN7-8; Two (2) 1,000kW diesel-fueled emergency reciprocating internal combustion engines	Diesel	PM (Total and LT) (10)	Good combustion practices.	1000	kW	0.15	G/B-HP-H	Test protocol; each unit	BACT-PSD
MI-0406	Renaissance Power LLC	MI	3/19/2014	FG-EMGEN7-8; Two (2) 1,000kW diesel-fueled emergency reciprocating internal combustion engines	Diesel	PM (Total and LT) (2.5)	Good combustion practices	1000	kW	0.15	G/B-HP-H	Test protocol; each unit	BACT-PSD
MI-0410	Thetford Generating Station	MI	8/1/2014	EU-FPENGINE: Diesel fuel fired emergency backup fire pump	diesel fuel	PM (Filterable)	Proper combustion design and ultra low sulfur diesel fuel.	315	HP nameplate	0.15	G/HP-H	Test protocol will specify avg. time	BACT-PSD
MI-0410	Thetford Generating Station	MI	8/1/2014	EU-FPENGINE: Diesel fuel fired emergency backup fire pump	diesel fuel	PM (Total and LT) (10)	Proper combustion design and ultra low sulfur diesel fuel	315	HP nameplate	0.6	LB/H	Test protocol will specify avg. time	BACT-PSD
MI-0410	Thetford Generating Station	MI	8/1/2014	EU-FPENGINE: Diesel fuel fired emergency backup fire pump	diesel fuel	PM (Total and LT) (2.5)	Proper combustion design and ultra low sulfur diesel fuel.	315	HP nameplate	0.6	LB/H	Test protocol will specify avg. time	BACT-PSD
MI-0412	Holland Board of Public Works - East 5th Street	MI	8/15/2014	Emergency Engine --Diesel Fire Pump (EUFPENGINE)	Diesel	PM (Filterable)	Good combustion practices	165	HP	0.22	G/HP-H	Test protocol	BACT-PSD
MI-0412	Holland Board of Public Works - East 5th Street	MI	8/15/2014	Emergency Engine --Diesel Fire Pump (EUFPENGINE)	Diesel	PM (Total and LT) (10)	Good combustion practices	165	HP	0.09	LB/MMBTU	Test protocol	BACT-PSD
MI-0412	Holland Board of Public Works - East 5th Street	MI	8/15/2014	Emergency Engine --Diesel Fire Pump (EUFPENGINE)	Diesel	PM (Total and LT) (2.5)	Good combustion practices	165	HP	0.09	LB/MMBTU	Test protocol	BACT-PSD
NJ-0079	Woodbridge Energy Center	NJ	11/27/2012	Emergency Generator	ULSD distillate	PM (Total and LT) (10)	Use of ULSD oil	100	H/YR	0.13	LB/H		Other case-by-case
NJ-0079	Woodbridge Energy Center	NJ	11/27/2012	Emergency Generator	ULSD distillate	PM (Total and LT) (2.5)	Use of ULSD oil	100	H/YR	0.13	LB/H		Other case-by-case
NJ-0081	PSEG Fossil LLC Sewaren Generating Station	NJ	8/22/2014	Emergency diesel fire pump	Ultra Low Sulfur Distillate oil	PM (Filterable)	Use of Ultra low sulfur distillate oil			0.15	G/B-HP-H		BACT-PSD
NJ-0081	PSEG Fossil LLC Sewaren Generating Station	NJ	8/22/2014	Emergency diesel fire pump	Ultra Low Sulfur Distillate oil	PM (Total and LT) (10)	Use of ultra low sulfur distillate oil			0.15	G/B-HP-H		BACT-PSD
NJ-0081	PSEG Fossil LLC Sewaren Generating Station	NJ	8/22/2014	Emergency diesel fire pump	Ultra Low Sulfur Distillate oil	PM (Total and LT) (2.5)	Use of Ultra low sulfur distillate oil			0.15	G/B-HP-H		Other case-by-case
NJ-0084	PSEG Fossil LLC Sewaren Generating Station	NJ	5/13/2016	Diesel Fired Emergency Generator	ULSD	PM (Filterable)	use of ULSD a clean burning fuel, and limited hours of operation	44	H/YR	0.26	LB/H		BACT-PSD
NJ-0084	PSEG Fossil LLC Sewaren Generating Station	NJ	5/13/2016	Diesel Fired Emergency Generator	ULSD	PM (Total and LT) (10)	use of ULSD a clean burning fuel, and limited hours of operation	44	H/YR	0.26	LB/H		BACT-PSD
NJ-0084	PSEG Fossil LLC Sewaren Generating Station	NJ	5/13/2016	Diesel Fired Emergency Generator	ULSD	PM (Total and LT) (2.5)	use of ULSD a clean burning fuel, and limited hours of operation	44	H/YR	0.26	LB/H		BACT-PSD
NJ-0084	PSEG Fossil LLC Sewaren Generating Station	NJ	5/13/2016	Emergency Diesel Fire Pump	ULSD	PM (Filterable)	use of ULSD a clean burning fuel, and limited hours of operation	100	H/YR	0.1	LB/H		BACT-PSD
NJ-0084	PSEG Fossil LLC Sewaren Generating Station	NJ	5/13/2016	Emergency Diesel Fire Pump	ULSD	PM (Total and LT) (10)	use of ULSD a clean burning fuel, and limited hours of operation	100	H/YR	0.1	LB/H		BACT-PSD

Table 6.4
Engines, Generators, and Pumps RBLC Review - PM

RBLC ID	Facility Name	State	Date of Determination	Process	Primary Fuel	Pollutant	Control Method	Throughput	Units	Emissions Limit	Units	Avg Condition	Basis
NJ-0084	PSEG Fossil LLC Sewaren Generating Station	NJ	5/13/2016	Emergency Diesel Fire Pump	ULSD	PM (Total and LT) (2.5)	use of ULSD a clean burning fuel, and limited hours of operation	100	H/YR	0.1	LB/H		BACT-PSD
NJ-0085	Middlesex Energy Center, LLC	NJ	7/27/2016	Emergency Diesel Fire Pump	ULSD	PM (Filterable)	Use of Ultra Low Sulfur Diesel (ULSD) Oil a clean burning fuel and limited hours of operation	100	H/YR	0.108	LB/H		BACT-PSD
NJ-0085	Middlesex Energy Center, LLC	NJ	7/27/2016	Emergency Diesel Fire Pump	ULSD	PM (Total and LT) (10)	Use of Ultra Low Sulfur Diesel (ULSD) Oil a clean burning fuel and limited hours of operation	100	H/YR	0.108	LB/H		BACT-PSD
NJ-0085	Middlesex Energy Center, LLC	NJ	7/27/2016	Emergency Diesel Fire Pump	ULSD	PM (Total and LT) (2.5)	Use of ULSD a clean burning fuel and limited hours of operation	100	H/YR	0.108	LB/H		BACT-PSD
NJ-0085	Middlesex Energy Center, LLC	NJ	7/27/2016	Emergency Generator Diesel	Diesel oil	PM (Filterable)	Use of Ultra Low Sulfur Diesel (ULSD) Oil a clean burning fuel and limited hours of operation		100 H/YR	0.661	LB/H		BACT-PSD
NJ-0085	Middlesex Energy Center, LLC	NJ	7/27/2016	Emergency Generator Diesel	Diesel oil	PM (Total and LT) (10)	Use of Ultra Low Sulfur Diesel (ULSD) Oil a clean burning fuel and limited hours of operation		100 H/YR	0.661	LB/H		BACT-PSD
NJ-0085	Middlesex Energy Center, LLC	NJ	7/27/2016	Emergency Generator Diesel	Diesel oil	PM (Total and LT) (2.5)	Use of Ultra Low Sulfur Diesel (ULSD) Oil a clean burning fuel and limited hours of operation		100 H/YR	0.661	LB/H		BACT-PSD
OH-0352	Oregon Clean Energy Center	OH	7/15/2013	Emergency fire pump engine	Diesel	PM (Total and LT) (10)	Purchased certified to the standards in NSPS Subpart IIII	300	HP	0.1	LB/H		BACT-PSD
OH-0352	Oregon Clean Energy Center	OH	7/15/2013	Emergency generator	Diesel	PM (Total and LT) (10)	Purchased certified to the standards in NSPS Subpart IIII	2250	KW	0.99	LB/H		BACT-PSD
OK-0154	Mooreland Generating Station	OK	6/18/2014	Diesel-fired emergency generator engine	Diesel	PM (Total and LT) (2.5)	Combustion control	1341	HP	0.44	LB/HR		BACT-PSD
PA-0278	Moxie Liberty LLC/Asylum Power Plant	PA	12/3/2012	Emergency Generator	Diesel	PM (Total and LT) (10)				0.02	G/B-HP-H		Other case-by-case
PA-0278	Moxie Liberty LLC/Asylum Power Plant	PA	12/3/2012	Emergency Generator	Diesel	PM (Total and LT) (2.5)				0.02	G/B-HP-H		Other case-by-case
PA-0278	Moxie Liberty LLC/Asylum Power Plant	PA	12/3/2012	Fire Pump	Diesel	PM (Total and LT) (10)				0.09	G/B-HP-H		Other case-by-case
PA-0278	Moxie Liberty LLC/Asylum Power Plant	PA	12/3/2012	Fire Pump	Diesel	PM (Total and LT) (2.5)				0.09	G/B-HP-H		Other case-by-case
PA-0286	Moxie Energy LLC/Patriot Generation Plant	PA	3/27/2013	Emergency Generator-Engine	Diesel	PM (Total and LT) (10)				0.02	GM/B-HP-H		Other case-by-case
PA-0286	Moxie Energy LLC/Patriot Generation Plant	PA	3/27/2013	Emergency Generator-Engine	Diesel	PM (Total and LT) (2.5)				0.02	GM/B-HP-H		Other case-by-case
PA-0286	Moxie Energy LLC/Patriot Generation Plant	PA	3/27/2013	Fire Pump Engine - 460 BHP	Diesel	PM (Total and LT) (10)				0.09	G/HP-H		Other case-by-case
PA-0286	Moxie Energy LLC/Patriot Generation Plant	PA	3/27/2013	Fire Pump Engine - 460 BHP	Diesel	PM (Total and LT) (2.5)				0.09	G/HP-H		Other case-by-case
PR-0009	Energy Answers Arecibo Puerto Rico Renewable Energy Project	PR	10/14/2014	Emergency Diesel Fire Pump	ULSD Fuel Oil #2	PM (Filterable)				0.15	G/B-HP-H		BACT-PSD
PR-0009	Energy Answers Arecibo Puerto Rico Renewable Energy Project	PR	10/14/2014	Emergency Diesel Fire Pump	ULSD Fuel Oil #2	PM (Total and LT) (10)				0.15	G/B-HP-H		BACT-PSD
PR-0009	Energy Answers Arecibo Puerto Rico Renewable Energy Project	PR	10/14/2014	Emergency Diesel Fire Pump	ULSD Fuel Oil #2	PM (Total and LT) (2.5)				0.15	G/B-HP-H		BACT-PSD
PR-0009	Energy Answers Arecibo Puerto Rico Renewable Energy Project	PR	10/14/2014	Emergency Diesel Generator	ULSD Fuel oil # 2	PM (Filterable)				0.15	G/B-HP-H		BACT-PSD
PR-0009	Energy Answers Arecibo Puerto Rico Renewable Energy Project	PR	10/14/2014	Emergency Diesel Generator	ULSD Fuel oil # 2	PM (Total and LT) (10)				0.15	G/B-HP-H		BACT-PSD
PR-0009	Energy Answers Arecibo Puerto Rico Renewable Energy Project	PR	10/14/2014	Emergency Diesel Generator	ULSD Fuel oil # 2	PM (Total and LT) (2.5)				0.15	G/B-HP-H		BACT-PSD

Table 7.1
Small Boilers RBLC Review - NO_x

RBLC ID	Facility Name	State	Date of Determination	Process	Primary Fuel	Pollutant	Control Method	Throughput	Units	Emissions Limit	Units	Avg Condition	Basis
AK-0082	Point Thomson Production Facility	AK	1/28/2015	Boilers and Heaters	Ultra Low Sulfur Diesel	NOx		7	MMBTU/HR	20	lb/1,000 gal		BACT-PSD
FL-0328	ENI - Holy Cross Drilling Project	FL	10/31/2011	Boiler	Diesel	NOx	Use of good combustion and maintenance practices, based on the current manufacturer's specifications for this boiler.	9.6	MMBTU/HR	0.49	tons/yr	12-month rolling	BACT-PSD
MD-0037	Medimmune Frederick Campus	MD	2/28/2008	Four (4) Diesel fired (back-up fuel) boilers each rated at 29.4 MMBTU/HR	Diesel (No. 2 fuel oil)	NOx		29.4	MMBTU/HR	58	PPM	Vol., dry basis, corr. to 3% O_2	Other case-by-case
MI-0400	Wolverine Power	MI	10/18/2012	Auxiliary Boiler	Diesel	NOx	Low NO_x burner	72.4	MMBTU/HR	1.67	lb/hr	Test protocol; BACT/SIP	BACT-PSD
NV-0047	Nellis Air Force Base	NV	10/21/2008	Boilers/heaters - diesel oil-fired	Diesel Oil	NOx	Low NO_x burner			0.14	lb/MMBTU		BACT-PSD
OH-0309	Toledo Supplier Park - Paint Shop	OH	5/3/2007	Boiler (2), No. 2 fuel oil	Fuel oil #2	NOx	Low NO_x burners and flue gas recirculation	20.4	MMBTU/HR	1.5	lb/hr		LAER
*WA-0349	Hanford	WA	4/9/2013	steam generating boiler	diesel	NOx	Low NO_x burners			0.09	lb/MMBTU	24-HR	BACT-PSD
*WA-0349	Hanford	WA	4/9/2013	Type I emergency generator	diesel	NOx	Good Combustion Practices			164	hr/yr	12-month rolling	BACT-PSD
*WA-0349	Hanford	WA	4/9/2013	turbine generators	diesel	NOx	Good Combustion Practices			164	hrs/week	12 consecutive months	BACT-PSD

Table 7.2
Small Boilers RBLC Review - SO_2

RBLC ID	Facility Name	State	Date of Determination	Process	Primary Fuel	Pollutant	Control Method	Throughput	Units	Emissions Limit	Units	Avg Condition	Basis
GA-0132	Yellow Pine Energy Company, LLC	GA	4/5/2010	Auxiliary boiler	Low sulfur	SO_2	Fuel sulfur content of distillate fuel of 0.05 weight which is reduced to 15 ppm by 2010: limited opertation and good combustion controls.			250	MMBTU/H	12 consecutive month period	BACT-PSD
NV-0047	Nellis Air Force Base	NV	10/21/2008	Boilers/heaters - diesel oil-fired	Diesel oil	SO_2	Limiting sulfur content in the diesel oil to 0.05% by weight			0.0094	LB/MMBTU		BACT-PSD
NV-0047	Nellis Air Force Base	NV	10/21/2008	Large internal combustion engines (>500 HP)	Diesel oil	SO_2	Limiting sulfur content in the diesel oil to 0.05%			0.02	G/B-HP-H		BACT-PSD
NV-0047	Nellis Air Force Base	NV	10/21/2008	Small internal combustion engines (<= 500 HP)	Diesel oil	SO_2	Limiting sulfur content in the diesel oil to 0.05%			0.99	G/B-HP-H		BACT-PSD
OH-0309	Toledo Supplier Park - Paint Shop	OH	5/3/2007	Boiler (2), No. 2 Fuel oil	Fuel oil #2	SO_2	0	20.4	MMBTU/HR	10.4	LB/H		BACT-PSD

Table 7.3
Small Boilers RBLC Review - PM

RBLC ID	Facility Name	State	Date of Determination	Process	Primary Fuel	Pollutant	Control Method	Throughput	Units	Emissions Limit	Units	Avg Condition	Basis
OH-0309	Toledo Supplier Park - Paint Shop	OH	5/3/2007	Boiler (2), No. 2 fuel oil	Fuel oil #2	PM		20.4	MMBTU/HR	0.31	lb/hr		BACT-PSD
AK-0082	Point Thomson Production Facility	AK	1/28/2015	Boilers and Heaters	ULSD	PM (Filterable and LT) (10)		7	MMBTU/HR	2.3	lb/1,000 gal		BACT-PSD
NV-0047	Nellis AFB	NV	10/21/2008	Boilers/heaters - diesel oil-fired	Diesel oil	PM (Filterable and LT) (10)	Good combustion practice			0.019	lb/MMBTU		Other Case-by-Case
OH-0309	Toledo Supplier Park - Paint Shop	OH	5/3/2007	Boiler (2), No. 2 fuel oil	Fuel oil #2	PM (Filterable and LT) (10)		20.4	MMBTU/HR	0.5	lb/hr		BACT-PSD
AK-0082	Point Thomson Production Facility	AK	1/28/2015	Boilers and Heaters	ULSD	PM (Filterable and LT) (2.5)		7	MMBTU/HR	1.55	lb/1,000 gal		BACT-PSD
MI-0400	Wolverine Power	MI	10/18/2012	Auxiliary Boiler	Diesel	PM (Filterable)		72.4	MMBTU/HR	0.11	lb/hr	Test protocol; BACT/SIP/MACT	BACT-PSD
MI-0400	Wolverine Power	MI	10/18/2012	Auxiliary Boiler	Diesel	PM (Total and LT) (10)		72.4	MMBTU/HR	2.17	lb/hr	Test protocol; BACT/SIP	BACT-PSD
*WA-0349	Hanford	WA	4/9/2013	Steam generating boiler	Diesel	PM (Total and LT) (10)	Good combustion practices			13400000	gal/yr	365 days	BACT-PSD
AK-0081	Point Thomson Production Facility	AK	8/30/2013	Combustion	ULSD	PM (Total and LT) (2.5)	Good combustion and operation practices			0.25	lb/gal		Other Case-by-Case
FL-0328	ENI - Holy Cross Drilling Project	FL	10/31/2011	Boiler	Diesel	PM (Total and LT) (2.5)	Use of good combustion and maintenance practices, based on the current manufacturer's specifications for this boiler.	9.6	MMBTU/HR	0.01	tons/yr	12-month rolling	BACT-PSD
MI-0400	Wolverine Power	MI	10/18/2012	Auxiliary Boiler	Diesel	PM (Total and LT) (2.5)		72.4	MMBTU/HR	2.17	lb/hr	Test protocol; BACT/SIP	BACT-PSD
FL-0328	ENI - Holy Cross Drilling Project	FL	10/31/2011	Boiler	Diesel	PM (Total) (10)	Use of good combustion and maintenance practices, based on the current manufacturer's specifications for this boiler.	9.6	MMBTU/HR	0.05	tons/yr	12-month rolling	BACT-PSD

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Table 8.1
Material Handling RBLC Review - PM

RBLC ID	Facility Name	State	Date of Determination	Process	Primary Fuel	Pollutant	Control Method	Throughput	Units	Emissions Limit	Units	Avg Condition	Basis
IN-0166	Indiana Gasification, LLC	IN	8/16/2013	Two (2) process area solid feedstock conveying, storage and feedbin		PM (Filterable)	Baghouse	750	T/H	0.003	GR/DSCF	3 hr avg	BACT-PSD
IN-0166	Indiana Gasification, LLC	IN	8/16/2013	Rail unloading to rail hoppers		PM (Filterable)	Wet dust extraction or a baghouse	750	T/H	0.003	GR/DSCF	3 hr avg	BACT-PSD
IN-0166	Indiana Gasification, LLC	IN	8/16/2013	Rail hoppers unloading to the conveyor belts and rail conveyor belt to the stacker		PM (Filterable)	Wet dust extraction or a baghouse	750	T/H	0.003	GR/DSCF	3 hr avg	BACT-PSD
IN-0166	Indiana Gasification, LLC	IN	8/16/2013	Transfer systems consisting of hoppers and conveyor belts transferring feed stock from the piles to classification towers		PM (Filterable)	Wet dust extraction or a baghouse	750	T/H	0.003	GR/DSCF	3 hr avg	BACT-PSD
IN-0166	Indiana Gasification, LLC	IN	8/16/2013	Two (2) process area solid feedstock conveying, storage and feedbin		PM (Total and LT) (10)	Baghouse	750	T/H	0.003	GR/DSCF	3 hr avg	BACT-PSD
IN-0166	Indiana Gasification, LLC	IN	8/16/2013	Rail unloading to rail hoppers		PM (Total and LT) (10)	Wet dust extraction or a baghouse	750	T/H	0.003	GR/DSCF	3 hr avg	BACT-PSD
IN-0166	Indiana Gasification, LLC	IN	8/16/2013	Rail hoppers unloading to the conveyor belts and rail conveyor belt to the stacker		PM (Total and LT) (10)	Wet dust extraction or a baghouse	750	T/H	0.003	GR/DSCF	3 hr avg	BACT-PSD
IN-0166	Indiana Gasification, LLC	IN	8/16/2013	Transfer systems consisting of hoppers and conveyor belts transferring feed stock from the piles to classification towers		PM (Total and LT) (10)	Wet dust extraction or a baghouse	750	T/H	0.003	GR/DSCF	3 hr avg	BACT-PSD
IN-0166	Indiana Gasification, LLC	IN	8/16/2013	Two (2) process area solid feedstock conveying, storage and feedbin		PM (Total and LT) (2.5)	Baghouse	750	T/H	0.003	GR/DSCF	3 hr avg	BACT-PSD
IN-0166	Indiana Gasification, LLC	IN	8/16/2013	Rail unloading to rail hoppers		PM (Total and LT) (2.5)	Wed dust extraction or a baghouse	750	T/H	0.0015	GR/DSCF	3 hr avg	BACT-PSD
IN-0166	Indiana Gasification, LLC	IN	8/16/2013	Rail hoppers unloading to the conveyor belts and rail conveyor belt to the stacker		PM (Total and LT) (2.5)	Wed dust extraction or a baghouse	750	T/H	0.0015	GR/DSCF	3 hr avg	BACT-PSD
IN-0166	Indiana Gasification, LLC	IN	8/16/2013	Transfer systems consisting of hoppers and conveyor belts transferring feed stock from the piles to classification towers		PM (Total and LT) (2.5)	Wed dust extraction or a baghouse	750	T/H	0.0015	GR/DSCF	3 hr avg	BACT-PSD
IN-0166	Indiana Gasification, LLC	IN	8/16/2013	Fugitive dust from paved roads		PM (Filterable)	Paving all plant haul roads, use of wet or chemical suppression, and prompt cleanup of any spilled materials.			90	% Control		BACT-PSD
IN-0166	Indiana Gasification, LLC	IN	8/16/2013	Fugitive dust from paved roads		PM (Total and LT) (10)	Paving all plant haul roads, use of wet or chemical suppression, and prompt cleanup of any spilled materials.			90	% Control		BACT-PSD
IN-0166	Indiana Gasification, LLC	IN	8/16/2013	Fugitive dust from paved roads		PM (Total and LT) (2.5)	Paving all plant haul roads, use of wet or chemical suppression, and prompt cleanup of any spilled materials.			90	% Control		BACT-PSD
IN-0166	Indiana Gasification, LLC	IN	8/16/2013	Two (2) storage piles		PM (Filterable)	Wet suppression with pile compaction	300000	tons each	90	% Control	3 hr avg	BACT-PSD
IN-0166	Indiana Gasification, LLC	IN	8/16/2013	Two (2) storage piles		PM (Total and LT) (10)	Wet suppression with pile compaction	300000	tons each	90	% Control	3 hr avg	BACT-PSD
IN-0166	Indiana Gasification, LLC	IN	8/16/2013	Two (2) storage piles		PM (Total and LT) (2.5)	Wet suppression with pile compaction	300000	tons each	90	% Control	3 hr avg	BACT-PSD
*MD-0042	Wildcat Point Generation Facility	MD	7/29/2016	Paved and unpaved roads									
IA-0105	Iowa Fertilizer Company	IA	8/13/2013	Haul Roads		PM (Total and LT) (10)	paved road, water flushing, and sweeping						BACT-PSD
IA-0105	Iowa Fertilizer Company	IA	8/13/2013	Haul Roads		PM (Total) (10)	paved road, water flushing, and sweeping						BACT-PSD
IA-0105	Iowa Fertilizer Company	IA	8/13/2013	Haul Roads		PM (Total and LT) (2.5)	paved road, water flushing, and sweeping						BACT-PSD
PR-0009	Energy Answers Arecibo Puerto Rico Renewable Energy Project	PR	5/5/2016	Ash Handling System and Storage Silos		PM (Filterable)	Fabric Filters			0.017	MG/DSCM		BACT-PSD
*LA-0296	Lake Charles Chemical Complex LDPE Unit	LA	9/15/2016	Bin B207 Vent (EQT 666)		PM (Filterable and LT) (10)	0			0.05	LB/HR	hourly maximum	BACT-PSD
*LA-0296	Lake Charles Chemical Complex LDPE Unit	LA	9/15/2016	Bin B208 Vent (EQT 667)		PM (Filterable and LT) (10)	Fabric filter			0.05	LB/HR	hourly maximum	BACT-PSD
*LA-0296	Lake Charles Chemical Complex LDPE Unit	LA	9/15/2016	Bin B207 Vent (EQT 666)		PM (Filterable and LT) (2.5)	0			0.05	LB/HR	hourly maximum	BACT-PSD
*LA-0296	Lake Charles Chemical Complex LDPE Unit	LA	9/15/2016	Bin B208 Vent (EQT 667)		PM (Filterable and LT) (2.5)	Fabric filter			0.05	LB/HR	hourly maximum	BACT-PSD
AR-0140	Big River Steel LLC	AR	12/13/2016	Dust exhaust SN-23A, tension leveler		PM (Filterable)	Fabric filter			0.003	GR/DSCF	0	BACT-PSD
AR-0140	Big River Steel LLC	AR	12/13/2016	Dust exhaust SN-23A, tension leveler		PM (Total and LT) (2.5)	Fabric filter			0.003	GR/DSCF	0	BACT-PSD
*LA-0309	Benteler Steel Tube Facility	LA	3/9/2017	Material Handling		PM (Total and LT) (10)	baghouses			0.005	GR/DSCF	3 one-hr test avg	BACT-PSD
*LA-0309	Benteler Steel Tube Facility	LA	3/9/2017	Material Handling		PM (Total and LT) (2.5)	baghouses			0.005	GR/DSCF	3 one-hr test avg	BACT-PSD
IN-0166	Indiana Gasification, LLC	IN	5/4/2016	Two (2) process area solid feedstock conveying, storage and feedbin		PM (Filterable)	baghouse	750	T/H	0.003	GR/DSCF	3 hr avg	BACT-PSD
IN-0166	Indiana Gasification, LLC	IN	5/4/2016	Rail unloading to rail hoppers		PM (Filterable)	Wed dust extraction or a baghouse	750	T/H	0.003	GR/DSCF	3 hr avg	BACT-PSD

Table 8.1
Material Handling RBLC Review - PM

RBLC ID	Facility Name	State	Date of Determination	Process	Primary Fuel	Pollutant	Control Method	Throughput	Units	Emissions Limit	Units	Avg Condition	Basis
IN-0166	Indiana Gasification, LLC	IN	5/4/2016	Rail hoppers unloading to the conveyor belts and rail conveyor belt to the stacker		PM (Filterable)	Wed dust extraction or a baghouse	750	T/H	0.003	GR/DSCF	3 hr avg	BACT-PSD
IN-0166	Indiana Gasification, LLC	IN	5/4/2016	Transfer systems consisting of hoppers and conveyor belts transferring feed stock from the piles to classification towers		PM (Filterable)	Wed dust extraction or a baghouse	750	T/H	0.003	GR/DSCF	3 hr avg	BACT-PSD
IN-0166	Indiana Gasification, LLC	IN	5/4/2016	Two (2) radial stackers to the pile		PM (Filterable)	Telescoping chute with dust collection	3000	T/H	0.003	GR/DSCF	3 hr avg	BACT-PSD
IN-0166	Indiana Gasification, LLC	IN	5/4/2016	Truck/rail conveyor transfer tower; truck stations unloading to a truck hopper; and truck hopper unloading to the conveyor belts		PM (Filterable)	Enclosed vent to a dust extraction system or baghouse	750	T/H	0.003	GR/DSCF	3 hr avg	BACT-PSD
IN-0166	Indiana Gasification, LLC	IN	5/4/2016	Two (2) process area solid feedstock conveying, storage and feedbin		PM (Total and LT) (10)	baghouse	750	T/H	0.003	GR/DSCF	3 hr avg	BACT-PSD
IN-0166	Indiana Gasification, LLC	IN	5/4/2016	Rail unloading to rail hoppers		PM (Total and LT) (10)	Wed dust extraction or a baghouse	750	T/H	0.003	GR/DSCF	3 hr avg	BACT-PSD
IN-0166	Indiana Gasification, LLC	IN	5/4/2016	Rail hoppers unloading to the conveyor belts and rail conveyor belt to the stacker		PM (Total and LT) (10)	Wed dust extraction or a baghouse	750	T/H	0.003	GR/DSCF	3 hr avg	BACT-PSD
IN-0166	Indiana Gasification, LLC	IN	5/4/2016	Transfer systems consisting of hoppers and conveyor belts transferring feed stock from the piles to classification towers		PM (Total and LT) (10)	Wed dust extraction or a baghouse	750	T/H	0.003	GR/DSCF	3 hr avg	BACT-PSD
IN-0166	Indiana Gasification, LLC	IN	5/4/2016	Two (2) radial stackers to the pile		PM (Total and LT) (10)	Telescoping chute with dust collection	3000	T/H	0.003	GR/DSCF	3 hr avg	BACT-PSD
IN-0166	Indiana Gasification, LLC	IN	5/4/2016	Truck/rail conveyor transfer tower; truck stations unloading to a truck hopper; and truck hopper unloading to the conveyor belts		PM (Total and LT) (10)	Enclosed vent to a dust extraction system or baghouse	750	T/H	0.003	GR/DSCF	3 hr avg	BACT-PSD
IN-0166	Indiana Gasification, LLC	IN	5/4/2016	Two (2) process area solid feedstock conveying, storage and feedbin		PM (Total and LT) (2.5)	Baghouse	750	T/H	0.003	GR/DSCF	3 hr avg	BACT-PSD
IN-0166	Indiana Gasification, LLC	IN	5/4/2016	Rail unloading to rail hoppers		PM (Total and LT) (2.5)	Wed dust extraction or a baghouse	750	T/H	0.0015	GR/DSCF	3 hr avg	BACT-PSD
IN-0166	Indiana Gasification, LLC	IN	5/4/2016	Rail hoppers unloading to the conveyor belts and rail conveyor belt to the stacker		PM (Total and LT) (2.5)	Wed dust extraction or a baghouse	750	T/H	0.0015	GR/DSCF	3 hr avg	BACT-PSD
IN-0166	Indiana Gasification, LLC	IN	5/4/2016	Transfer systems consisting of hoppers and conveyor belts transferring feed stock from the piles to classification towers		PM (Total and LT) (2.5)	Wed dust extraction or a baghouse	750	T/H	0.0015	GR/DSCF	3 hr avg	BACT-PSD
IN-0166	Indiana Gasification, LLC	IN	5/4/2016	Two (2) radial stackers to the pile		PM (Total and LT) (2.5)	Telescoping chute with dust collection	3000	T/H	0.0015	GR/DSCF	3 hr avg	BACT-PSD
IN-0166	Indiana Gasification, LLC	IN	5/4/2016	Truck/rail conveyor transfer tower; truck stations unloading to a truck hopper; and truck hopper unloading to the conveyor belts		PM (Total and LT) (2.5)	Enclosed vent to a dust extraction system or baghouse	750	T/H	0.0015	GR/DSCF	3 hr avg	BACT-PSD
IN-0166	Indiana Gasification, LLC	IN	5/4/2016	Fugitive dust from paved roads		PM (Filterable)	Paving all plant haul roads, use of wet or chemical suppression, and prompt cleanup of any spilled materials.			90	% Control		BACT-PSD
IN-0173	Midwest Fertilizer Corporation	IN	5/4/2016	Fugitive dust from paved roads		PM (Filterable)	Pave all haul roads, daily sweeping with wet suppression, prompt cleanup of any spilled material.	10402	vehicle miles traveled	90	% Control	Continuous	BACT-PSD
IN-0179	Ohio Valley Resources, LLC	IN	5/4/2016	Paved roadways and parking lots with public access		PM (Filterable)	Pave all plant haul roads, daily sweeping and wet suppression, prompt cleanup of any spilled material	17160	vehicle miles traveled	90	% Control	Continuous	BACT-PSD
IN-0180	Midwest Fertilizer Corporation	IN	5/5/2016	Fugitive dust from paved roads and parking lots		PM (Filterable)	Pave all haul roads, daily sweeping with wet suppression, prompt cleanup of any spilled material.	10402	vehicle miles traveled	90	% Control	Continuous	BACT-PSD
*OK-0156	Northstar Agri Ind Enid	OK	12/6/2016	Haul Roads		PM, Fugitive	Paved Haul Roads						BACT-PSD
IA-0106	CF Industries Nitrogen, LLC - Port Neal Nitrogen Complex	IA	5/4/2016	New Plant Haul Road		PM (Total and LT) (10)	paved road, water flushing, and sweeping						BACT-PSD
IN-0166	Indiana Gasification, LLC	IN	5/4/2016	Fugitive dust from paved roads		PM (Total and LT) (10)	Paving all plant haul roads, use of wet or chemical suppression, and prompt cleanup of any spilled materials.			90	% Control		BACT-PSD
IN-0173	Midwest Fertilizer Corporation	IN	5/4/2016	Fugitive dust from paved roads and parking lots		PM (Total and LT) (10)	Pave all plant haul roads, daily sweeping and wet suppression, prompt cleanup of any spilled material	10402	vehicle miles traveled	90	% Control	Continuous	BACT-PSD
IN-0179	Ohio Valley Resources, LLC	IN	5/4/2016	Paved roadways and parking lots with public access		PM (Total and LT) (10)	Pave all plant haul roads, daily sweeping and wet suppression, prompt cleanup of any spilled material	17160	vehicle miles traveled	90	% Control	Continuous	BACT-PSD
IN-0180	Midwest Fertilizer Corporation	IN	5/5/2016	Fugitive dust from paved roads and parking lots		PM (Total and LT) (10)	Pave all plant haul roads, daily sweeping and wet suppression, prompt cleanup of any spilled material	10402	vehicle miles traveled	90	% Control	Continuous	BACT-PSD
IA-0106	CF Industries Nitrogen, LLC - Port Neal Nitrogen Complex	IA	5/4/2016	New Plant Haul Road		PM (Total and LT) (2.5)	paved road, water flushing, and sweeping						BACT-PSD
IN-0166	Indiana Gasification, LLC	IN	5/4/2016	Fugitive dust from paved roads		PM (Total and LT) (2.5)	Paving all plant haul roads, use of wet or chemical suppression, and prompt cleanup of any spilled materials.			90	% Control		BACT-PSD
IN-0173	Midwest Fertilizer Corporation	IN	5/4/2016	Fugitive dust from paved roads and parking lots		PM (Total and LT) (2.5)	Pave all haul roads, daily sweeping with wet suppression, prompt cleanup of any spilled material.	10402	vehicle miles traveled	90	% Control	Continuous	BACT-PSD
IN-0179	Ohio Valley Resources, LLC	IN	5/4/2016	Paved roadways and parking lots with public access		PM (Total and LT) (2.5)	Pave all plant haul roads, daily sweeping and wet suppression, prompt cleanup of any spilled material	17160	vehicle miles traveled	90	% Control	Continuous	BACT-PSD

Table 8.1
Material Handling RBLC Review - PM

RBLC ID	Facility Name	State	Date of Determination	Process	Primary Fuel	Pollutant	Control Method	Throughput	Units	Emissions Limit	Units	Avg Condition	Basis
IN-0180	Midwest Fertilizer Corporation	IN	5/5/2016	Fugitive dust from paved roads and parking lots		PM (Total and LT) (2.5)	Pave all plant haul roads, daily sweeping and wet suppression, prompt cleanup of any spilled material	10402	vehicle miles traveled	90	% Control	Continuous	BACT-PSD
IA-0106	CF Industries Nitrogen, LLC - Port Neal Nitrogen Complex	IA	5/4/2016	New Plant Haul Road		PM (Total) (10)	paved road, water flushing, and sweeping						BACT-PSD
IN-0166	Indiana Gasification, LLC	IN	5/4/2016	Two (2) storage piles		PM (Filterable)	Wet suppression with pile compaction	300000	tons each	90	% Control	3 hr avg	BACT-PSD
IN-0166	Indiana Gasification, LLC	IN	5/4/2016	Two (2) storage piles		PM (Total and LT) (10)	Wet suppression with pile compaction	300000	tons each	90	% Control	3 hr avg	BACT-PSD
IN-0166	Indiana Gasification, LLC	IN	5/4/2016	Two (2) storage piles		PM (Total and LT) (2.5)	Wet suppression with pile compaction	300000	tons each	90	% Control	3 hr avg	BACT-PSD
SC-0113	Pyramax Ceramics, LLC	SC	10/17/2012	90.009	23.3		Baghouse	T/H	The construction permit authorized the construction of four (4) identical process lines. This process and pollutant information is for one single process line.	0.005	GR/DSCF		BACT-PSD
SC-0113	Pyramax Ceramics, LLC	SC	10/17/2012	90.009	23.3		Baghouse	T/H	The construction permit authorized the construction of four (4) identical process lines. This process and pollutant information is for one single process line.	0.005	GR/DSCF		BACT-PSD
SC-0113	Pyramax Ceramics, LLC	SC	10/17/2012	90.009	23.3		Baghouse	T/H	The construction permit authorized the construction of four (4) identical process lines. This process and pollutant information is for one single process line.	0.005	GR/DSCF		BACT-PSD
PR-0009	Energy Answers Arecibo Puerto Rico Renewable Energy Project	PR	5/5/2016	21.4			Fabric Filters		Ash Handling System comprises of bottom ash handling and conveying system, bottom ash storage and conveying system, bottom ash processing activities, fly ash conveying, storage silo, conditioning and loading system. Storage silos comprise of carbon handling system and storage silo, and lime	0.017	MG/DSCM		BACT-PSD
IN-0185	MAG Pellet LLC	IN	5/13/2016	90.021			Baghouse			0.002	GR/DSCF		BACT-PSD
IN-0173	Midwest Fertilizer Corporation	IN	5/4/2016	99.14	10402		Pave all haul roads, daily sweeping with wet suppression, prompt cleanup of any spilled material	Vehicle miles traveled		90	% Control	Continuous	BACT-PSD
IN-0180	Midwest Fertilizer Corporation	IN	5/5/2016	99.14	10402		Pave all haul roads, daily sweeping with wet suppression, prompt cleanup of any spilled material	Vehicle miles traveled		90	% Control	Continuous	BACT-PSD
MD-0046	Keys Energy Center	MD	5/13/2016	99.999			Minimize emissions by taking reasonable precautions to prevent particulate matter from becoming airborne by sweeping or water application dust control. as needed.						BACT-PSD
*OK-0156	Northstar Agri Ind Enid	OK	12/6/2016	99.14			Paved Haul Roads						BACT-PSD
*OK-0145	Broken Bow OSB Mill	OK	12/7/2016	30.54	80		Baghouse/Fabric filter	ODT/hr					BACT-PSD
IA-0105	Iowa Fertilizer Company	IA	8/13/2013	99.14			paved road, water flushing, and sweeping		There are two (2) paved haul roads. The length of one is 0.97 miles and the other is 1.07 miles long.				BACT-PSD
IN-0173	Midwest Fertilizer Corporation	IN	5/4/2016	99.14	10402		Pave all haul roads, daily sweeping with wet suppression, prompt cleanup of any spilled material	Vehicle miles traveled		90	% Control	Continuous	BACT-PSD
IN-0180	Midwest Fertilizer Corporation	IN	5/5/2016	99.14	10402		Pave all haul roads, daily sweeping with wet suppression, prompt cleanup of any spilled material	Vehicle miles traveled		90	% Control	Continuous	BACT-PSD

Table 8.1
Material Handling RBLC Review - PM

RBLC ID	Facility Name	State	Date of Determination	Process	Primary Fuel	Pollutant	Control Method	Throughput	Units	Emissions Limit	Units	Avg Condition	Basis
MD-0046	Keys Energy Center	MD	5/13/2016	99.999			Minimize emissions by taking reasonable precautions to prevent particulate matter from becoming airborne by sweeping or water application dust control. as needed.						BACT-PSD
IA-0105	Iowa Fertilizer Company	IA	8/13/2013	99.14			paved road, water flushing, and sweeping		There are two (2) paved haul roads. The length of one is 0.97 miles and the other is 1.07 miles long.				BACT-PSD
IN-0173	Midwest Fertilizer Corporation	IN	5/4/2016	99.14	10402		Pave all haul roads, daily sweeping with wet suppression, prompt cleanup of any spilled material	Vehicle miles traveled		90	% Control	Continuous	BACT-PSD
IN-0180	Midwest Fertilizer Corporation	IN	5/5/2016	99.14	10402		Pave all haul roads, daily sweeping with wet suppression, prompt cleanup of any spilled material	Vehicle miles traveled		90	% Control	Continuous	BACT-PSD
IA-0105	Iowa Fertilizer Company	IA	8/13/2013	99.14			paved road, water flushing, and sweeping		There are two (2) paved haul roads. The length of one is 0.97 miles and the other is 1.07 miles long.				BACT-PSD
IA-0105	Iowa Fertilizer Company	IA	8/13/2013	99.14			paved road, water flushing, and sweeping		There are two (2) paved haul roads. The length of one is 0.97 miles and the other is 1.07 miles long.		% opacity		BACT-PSD
WI-0253	Oak Street Station	WI	7/6/2016	11.11			fugitive dust plan that includes: trained Method 9 observer; water sprays; wind barrier; crusting agents; video monitoring of the coal piles; study of additional control measures for feasibility		Expand existing coal storage	7.5	% opacity	6 minutes	BACT-PSD

APPENDIX A

BACT WORK PLAN

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FINAL

BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS WORK PLAN FORT WAINWRIGHT, FAIRBANKS, ALASKA

PERMIT AQ1121TVP02 (REV 2, AUGUST 19, 2016)
PERMIT AQ0236TVP03 (REV 2, DECEMBER 22, 2015)

Prepared for

U.S. Army Corps of Engineers
Huntsville District

Contract W912DY-10-D-0023
Task Order 0027

Prepared by

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April 2017

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FINAL

BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS WORK PLAN FORT WAINWRIGHT, FAIRBANKS, ALASKA

PERMIT AQ1121TVP02 (REV 2, AUGUST 19, 2016)
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TABLE OF CONTENTS

TABLES

APPENDICES

LIST OF ACRONYMS AND ABBREVIATIONS

acfm	actual cubic feet per minute
ADEC	Alaska Department of Environmental Conservation
BACT	Best Available Control Technology
BTU	British Thermal Unit
CFR	Code of Federal Regulations
CHPP	Central Heat and Power Plant
DU	Doyon Utilities, LLC
EPA	U.S. Environmental Protection Agency
EU	Emission Unit
EUAC	Equivalent Uniform Annual Cost
FNSB	Fairbanks North Star Borough
FWA	U.S. Army Garrison Fort Wainwright
hp	horsepower
ID	identification
LAER	Lowest Achievable Emission Rate
MMBTU/hr	Million BTU per hour
NAAQS	National Ambient Air Quality Standard
NESHAP	National Emission Standards for Hazardous Air Pollutants
NH_3	ammonia
NO_X	total nitrogen oxides
NSPS	New Source Performance Standards
PEU	Privatized Emission Unit
$PM_{2.5}$	Particulate matter with a diameter less than or equal to 2.5 micrometers
PM_{10}	Particulate matter with a diameter less than or equal to 10 micrometers
PTE	Potential to Emit
RACT	Reasonably Available Control Technology
RBLC	RACT/BACT/LAER Clearinghouse
RICE	reciprocating internal combustion engine
SIP	State Implementation Plan
SO_2	sulfur dioxide

LIST OF ACRONYMS AND ABBREVIATIONS (continued)

tpy	tons per year
VOC	volatile organic compound

FINAL

BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS WORK PLAN FORT WAINWRIGHT, FAIRBANKS, ALASKA

1.0 INTRODUCTION

The U.S. Environmental Protection Agency (EPA) designated portions of the Fairbanks North Star Borough (FNSB), including the city of Fairbanks and the city of North Pole, as a moderate nonattainment area for the 24-hour averaging period fine particulate matter ($PM_{2.5}$, particulate matter with a diameter less than 2.5 micrometers) in 2009 (EPA, 2009). The Alaska Department of Environmental Conservation (ADEC) expects EPA to change this designation from moderate (EPA, 2017) to serious in or about April 2017, based on the failure to attain compliance with the 24-hour average $PM_{2.5}$ National Ambient Air Quality Standard (NAAQS) through the measures implemented to bring the moderate nonattainment area into attainment (EPA, 2016).

One element of the attainment plan that ADEC must prepare for EPA approval is determining Best Available Control Technology (BACT) for certain stationary sources located in the nonattainment area. The U.S. Army Garrison Fort Wainwright (FWA) Privatized Emission Units (PEU), owned and operated by Doyon Utilities, LLC (DU), Permit No. AQ1121TVP02 Revision 2, is a stationary source for which a BACT analysis is required. In a letter dated April 24, 2015, ADEC asked DU to voluntarily prepare a BACT analysis that ADEC could then incorporate into the attainment planning process (see Appendix A). ADEC made this request because the agency "has neither the funding nor the in-depth knowledge of your facility's infrastructure to determine the most appropriate BACT for your facility."

Similarly, FWA also received the request to conduct a voluntary BACT for the significant units at the Garrison not otherwise included in the DU permit. The Garrison units are addressed in Permit No. AQ0236TVP03 (Rev 2, December 22, 2015). This work plan protocol addresses both of these facilities. DU and FWA are responding to this request by submitting this BACT analysis protocol to ADEC for review, comment, and approval.

The BACT analyses completed will inform ADEC and EPA actions as the state and Federal governments consider the Serious Nonattainment designation. ADEC and EPA have each published significant information regarding this process (ADEC, 2017a; ADEC, 2017b; EPA, 2016; and EPA, 2017).

1.1 POLLUTANTS SUBJECT TO BACT REVIEW

Even though the Garrison and Privatized Units operate under separate Title V permits, the determination regarding which sources are subject to BACT review for total nitrogen oxides (NO_X), sulfur dioxide (SO_2), volatile organic compounds (VOC), and $PM_{2.5}$ aggregates the emissions from the two facilities. Table 1.1 provides the potential to emit for the significant emission sources as listed in the DU FWA (PEUs) and U.S. Army FWA permits (Permit Nos. AQ1121TVP02 Revision 2 and AQ0236TVP03 Revision 2).

Based on the potential emissions summarized in Table 1.1 and included in the two facilities' operating permits, the significant stationary source potential $PM_{2.5}$, NO_X, and SO_2 emissions exceed 70 tons per year (tpy). BACT analyses will be prepared for direct $PM_{2.5}$ and will also consider NO_X and SO_2 as $PM_{2.5}$ precursors. BACT analyses will not be prepared for VOC and ammonia (NH_3).

1.2 GROUPING OF SOURCES FOR BACT ANALYSIS

The BACT Analysis will group similar sources for purposes of reviewing available control options and selecting BACT. Groupings to be employed are shown in Table 1.2 (Doyon) and Table 1.3 (FWA Garrison). For a given grouping, the BACT analysis will consider the largest of the sources for evaluation. The conclusions of the analysis will be conservatively applied to the smaller sources in the same category. Section 3 of this work plan summarize the groupings and pollutants to be considered.

Tables 1.4 and 1.5 summarize the insignificant sources of emissions at the Doyon Utilities facility and the FWA Garrison, respectively. The potential emissions associated with these insignificant activities are shown in Table 1.6.

The BACT Report will summarize previously-provided potential (as well as reported actual) emissions from these sources to comprehensively address both facilities operations within the BACT report. The Title V permit applications submitted for the two facilities addressed potential emission calculations in close detail. In the event the assumptions made during permitting no longer represent a reasonable potential to emit calculation methodology, the BACT Analysis will include such demonstrations.

2.0 BACT ANALYSIS APPROACH

The methodology that will be used for identifying BACT will be the five step "top-down" process set forth in the draft New Source Review Workshop Manual (EPA, 1990), in 40 Code of Federal Regulations (CFR) 51 and 52 (EPA, 1996), and is outlined in the following subsections.

2.1 STEP 1 – IDENTIFY ALL CONTROL TECHNOLOGIES

The first step of the BACT analysis will be to survey alternative control techniques and identify all "available" control options. Available control options are those air pollution control technologies or techniques with a practical potential for application to the emissions units and pollutants under evaluation. The following guidelines are used to identify available control options:

- The technology should be "demonstrated in practice." The control technology should have been installed and operating at a minimum of 50 percent of capacity for 6 months, and the performance should have been verified with a test or operational data at 90 percent of operational capacity.
- Controls applied to similar source categories, gas streams, and innovative control technologies should be examined. Process controls, such as combustion modifications, that are currently available from a supplier should be reviewed.
- The Reasonably Available Control Technology (RACT)/BACT/Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC) maintained by EPA will be reviewed for potential control technologies. The search criteria will use filtered results based on size, fuel, and source types.

2.2 STEP 2 – ELIMINATE TECHNICALLY INFEASIBLE CONTROL OPTIONS

In the second step, the technical feasibility of each available control option will be evaluated based on source-specific factors. The use of control options, which would clearly result in technical difficulties precluding their successful use, will be deemed technically infeasible. Likewise, the BACT Analysis will address the unique challenges of applying BACT to a potential retrofit scenario. Usually, BACT is employed as part of construction permitting of a greenfield source. In the event a control technology is infeasible as part of a retrofit process, the BACT report will detail these constraints. The control options will also be assessed considering the sub-Arctic environment into which deployment will be required. The limitations regarding fuel, space, and environmental conditions will be addressed in detail.

2.3 STEP 3 – RANK REMAINING CONTROL OPTIONS BY EFFECTIVENESS

In the third step, the effectiveness of control alternatives will be determined for all options not eliminated in step two. Control options are then ranked "top-down" in order of overall control effectiveness for the pollutant under review. Control options resulting in emissions that exceed

Federal New Source Performance Standards (NSPS) or National Emission Standards for Hazardous Air Pollutants (NESHAP) applicable to the source will be eliminated.

2.4 STEP 4 – EVALUATE MOST EFFECTIVE CONTROL OPTIONS

In the fourth step, the energy, environmental, and economic impacts of control options will be considered, beginning with the top-ranked control alternative. If the most effective control option is shown to be inappropriate due to adverse impacts, the option will be eliminated and the next-most stringent alternative will be evaluated. If the most stringent technology is selected as BACT, continuing the analysis will not be necessary.

2.5 STEP 5 – SELECT BACT

Finally, in the fifth step, the most effective control option not eliminated in step four will be proposed as BACT for the pollutant and emission unit under review.

The basis for comparing the economic impacts of control scenarios will be cost effectiveness. This value is defined as the total net annualized cost of control, divided by the tons of pollutant removed per year, for each control technique. Annualized costs include the annualized capital cost plus the financial requirements to operate the control system on an annual basis, including operating and maintenance labor, replacement parts, overhead, raw materials, and utilities.

In determining the amount of pollutant that will be removed for a given control option deployment, the BACT analysis will detail the facility's potential emissions for NO_X, SO_2, and $PM_{2.5}$. This calculated potential to emit may differ from the two facilities' Title V permits and will be used only for the cost effectiveness determination of a given technological option.

Capital costs include both the direct and indirect costs to install the equipment. Direct installation costs include costs for foundations, erection, electrical, piping, insulation, painting, site preparation, and buildings. Indirect installation costs include costs for engineering and supervision, construction expenses, startup costs, and contingencies.

For the analysis, all costs are expressed as an annualized cost, and cost-effectiveness values are then calculated. This approach of amortizing the investment into equal end-of-year annual costs is termed the Equivalent Uniform Annual Cost (EUAC), and EPA recommends this method for estimating control costs (EPA, 2002). Templates for cost estimation purposes can be found in Appendix B.

For the purposes of the BACT analysis, if a particular control technology is eliminated based on economic factors, the assumption will be made that the control technology is also uneconomic for smaller emission units provided that all other factors other than size are equivalent.

2.6 DOCUMENTATION

Supporting documentation for the nonattainment BACT analysis will be provided and will include data to support control effectiveness assertions, cost estimates, and justification for eliminating control options based environmental or economic determinations, if applicable. Cost estimates will be completed on emission unit specific information.

The BACT Analysis will identify the basis for each input value and assumption used in the calculations and analysis. Information will be presented within the report's appendix or with electronic links within the document, as applicable.

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3.0 STATIONARY SOURCE DESCRIPTION

This section provides a description of the stationary sources based on information provided in the two operating permits, AQ1121TVP02 and AQ0236TVP03. Sections 3.1 and 3.2 provide a BACT applicability analysis. Section 3.2 also provides a description of the FWA stationary source and a detailed emission unit inventory for the DU FWA (PEUs) stationary source.

3.1 DU FWA (PEUs) BACT ANALYSIS

As previously introduced, Table 1.2 provides an emission unit inventory for the DU FWA (PEUs) stationary source. The DU FWA facility consists of a Central Heat and Power Plant (CHPP), which includes six coal-fired boilers and a coal preparation plant. Backup power generation is provided by multiple diesel-fired reciprocating internal combustion engine (RICE) generators. Emergency backup for lift station pumps for the wastewater collection system is provided by diesel-fired RICE and pumps at multiple locations throughout the FWA (PEUs) stationary source. The BACT analysis will consider the emission units as identified in Table 1.2.

In summary, $PM_{2.5}$, NO_X, and SO_2 BACT analyses will be completed for the following emission units:

- Emission unit (EU) identifications (ID) 1 through 6, coal-fired boilers;
- EU ID 8, black start generator engine; and
- EU IDs 9 through 32 and 34 through 36, emergency engines. (EU ID 33 was permanently removed from service as described in the off-permit change notification submitted on October 2, 2015.)

A $PM_{2.5}$ BACT analysis will also be completed for EU IDs 7a, 7b, 7c, 51a, 51b, and 52.

3.2 FWA BACT ANALYSIS

As previously introduced, Table 1.3 provides an emission unit inventory for the Garrison stationary source. The Garrison consists of boilers and emergency generators and engines. The BACT Analysis will consider the emission units as identified in Table 1.3.

In summary, $PM_{2.5}$, NO_X, and SO_2 BACT analyses will be completed for the following source categories:

- Boilers,
- Emergency Generators, and
- Emergency Engines.

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4.0 SUMMARY OF SOURCES, POLLUTANTS, AND SCENARIOS TO BE CONSIDERED IN BACT ANALYSIS

DU and FWA Garrison are committed to providing ADEC with the necessary information to support its State Implementation Plan (SIP) revision efforts (ADEC, 2017a; 2017b) as dictated by the Clean Air Act and through EPA's SIP review (EPA, 2015). The BACT analysis will address the following sources/pollutant combinations:

Source Category	Unit Description	SO_2	NO_X	$PM_{2.5}$
Coal Fired Boilers	DU Units 1 through 6	✓	✓	✓
Distillate Fired Boilers	FWA	✓	✓	✓
Waste Oil Fired Boiler	FWA	✓	✓	✓
Black Start Generator	DU	✓	✓	✓
Emergency Engines	DU and FWA	✓	✓	✓
Emergency Fire Pumps	DU	✓	✓	✓
Emergency Generators	DU and FWA	✓	✓	✓
Coal Handling Activities	DU			✓
Ash Handling Activities	DU			✓
Coal Pile	DU			✓

The BACT analysis will consider normal operating scenarios for these sources/pollutant combinations. The startup and shut down periods will not be addressed as a separate scenario. Because these units are not cycling continuously, the startup and shut down periods do not represent a significant period of the overall operation. Thus, the analysis and the emissions controlled from the application of any potential control technology will assume normal operations.

Potential emissions from emergency equipment will be calculated using 500 hours per year as recommended by Mr. John Seitz, Director Office of Air Quality Planning and Standards (MD-10), in a letter dated September 6, 1995, to the various states and EPA Regional Directors (see Appendix C).

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5.0 REFERENCES

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Fort Wainwright, 2013. "Forms D1 and D2 Revised 080913.xls" as incorporated into ADEC 2015. Provided by Fort Wainwright March 17, 2017.

TABLES

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Table 1.1
Fort Wainwright Serious Nonattainment Area Major Source Applicability

Pollutant	Potential Emissions (TPY)			> 70 tpy Potential to Emit (PTE)?
	Doyon Utilities, LLC	U.S. Army	Total	
$PM_{2.5}$	124.3[1]	3.1[2]	127.4	Yes
SO_2	1,767.2[1]	46.9[2]	1,814.1	Yes
NO_X	1,532.9[1]	64.8[2]	1,597.7	Yes
VOC[4]	12.3[1]	44.4[2]	56.7	No
NH_3	< 1[3]	NA[4]	< 1 (estimated)	No

[1] From Table D of AQ1121TVP02 Revision 2 SOB (ADEC, 2016)
[2] From Table D of AQ0236TVP03 Revision 2 SOB (ADEC, 2015)
[3] Estimated potential emissions based on 336,000 tpy coal combustion limit and 0.565 lb/1,000-ton emission factor from WebFIRE (EPA, 2015)
[4] The Garrison's operations also include a Remediation site. During permitting activities for the Remediation site, the Garrison accepted a 30 ton/year VOC limit. The permit also requires monthly monitoring of VOC emissions. Monitoring data indicate zero VOC emissions from the Remediation activities. The BACT submittal will provide the documentation related to the calculation for VOC Potential to Emit to demonstrate that the Garrison and its Privatized Units are not subject to BACT for VOC.

Notes: The potential emissions which may be employed during the BACT analysis may differ from these values. The BACT analysis will use emission factors which most-accurately reflect potential emissions (rather than the AP-42 factors applied for permitting purposes previously). The Potential to Emit listed in the referenced permit does not create an enforceable limit on the emission units.

Table 1.2
Doyon Utilities Significant Privatized Emission Units for BACT Analysis

Emission Unit				Installation Date	Fuel Type	Rating	
ID	**Name**	**Description**	**Bldg. No.**				
Coal Fired Boilers							
1	Coal-Fired Boiler 3	CHPP	CHPP	1953	Coal	230	MMBtu/hr
2	Coal-Fired Boiler 4	CHPP	CHPP	1953	Coal	230	MMBtu/hr
3	Coal-Fired Boiler 5	CHPP	CHPP	1953	Coal	230	MMBtu/hr
4	Coal-Fired Boiler 6	CHPP	CHPP	1953	Coal	230	MMBtu/hr
5	Coal-Fired Boiler 7	CHPP	CHPP	1953	Coal	230	MMBtu/hr
6	Coal-Fired Boiler 8	CHPP	CHPP	1953	Coal	230	MMBtu/hr
Material Handling - Coal							
7a	South Coal Handling Dust Collector (DC-01)	Airlanco 169-AST-8	CHPP	2001	N/A	13,150	acfm
7b	South Underbunker Dust Collector (DC-02)	Airlanco 16-AST	CHPP	2005	N/A	884	acfm
7c	North Coal Handling Dust Collector (NDC-1)	Dustex C67-10-547	CHPP	2004	N/A	9,250	acfm
Distillate Fueled Emergency and Black Start Generators							
8	Black Start Generator Engine	Caterpillar 3516C	CHPP	2009	Distillate	2,937	hp
9	Generator Engine	Detroit 6V92	1032	1988	Distillate	353	hp
10	Generator Engine	Caterpillar C15	1060	2010	Distillate	762	hp
11	Generator Engine	Caterpillar C15	1060	2010	Distillate	762	hp
12	Generator Engine	Cummins B3.3	1193	2002	Distillate	82	hp
13	Generator Engine	Caterpillar 3406C TA	1555	2008	Distillate	587	hp
14	Generator Engine	Cummins QSL-G2 NR3	1563	2008	Distillate	320	hp
15	Generator Engine	Detroit R1237M36	2117	2005	Distillate	1,059	hp
16	Generator Engine	John Deere 6068TF250	2117	2005	Distillate	212	hp
17	Generator Engine	John Deere 6068TF250	2088	2007	Distillate	176	hp
18	Generator Engine	John Deere 6068HF150	2296	2005	Distillate	212	hp
19	Generator Engine	John Deere 4045TF270	3004	2007	Distillate	71	hp
20	Generator Engine	John Deere 4239D	3028	1976	Distillate	35	hp
21	Generator Engine	Perkins 2046/1800	3407	2001	Distillate	95	hp
22	Generator Engine	Cummins	3565	1989	Distillate	35	hp
23	Generator Engine	John Deere 6068HF150	3587	2003	Distillate	155	hp
24	Generator Engine	Cummins L634D-I/10386E	3703	1993	Distillate	50	hp
25	Generator Engine	Caterpillar C1.5	5108	2011	Distillate	18	hp
26	Generator Engine	Cummins 4B3.9-G2	1620	2003	Distillate	68	hp
27	Generator Engine	Caterpillar C6.6	1054	2010	Distillate	274	hp
28	Generator Engine	Caterpillar C6.6	4390	2010	Distillate	274	hp
29	Lift Pump Engine	Detroit Diesel 5116493	1056	1988	Distillate	75	hp
30	Lift Pump Engine	Detroit Diesel 10245100	3403	1952	Distillate	75	hp
31	Lift Pump Engine	Detroit Diesel 10245100	3724	1952	Distillate	75	hp
32	Lift Pump Engine	Perkins	4162	1955	Distillate	75	hp
34	Well Pump Engine	Detroit Diesel 10447000	3405	1995	Distillate	220	hp
35	Well Pump Engine	John Deere 4045DF120	4023	2009	Distillate	85	hp
36	Well Pump Engine	Detroit Diesel 4031-C	3563	1995	Distillate	220	hp

Table 1.2 (continued)
Doyon Utilities Significant Privatized Emission Units for BACT Analysis

Emission Unit				Install-ation Date	Fuel Type	Rating	
ID	**Name**	**Description**	**Bldg. No.**				
Material Handling - Ash							
51a	Fly Ash Dust Collector (DC-1)	United Conveyor Corp. 32242	CHPP	1993	N/A	3,620	acfm
51b	Bottom Ash Dust Collector (DC-2)	United Conveyor Corp. 32242	CHPP	1994	N/A	3,620	acfm
Material Handling – Coal Pile							
52	Coal Storage Pile	CHPP	CHPP	Unknown	N/A	N/A	

acfm – actual cubic feet per minute
CHPP – Central Heat and Power Plant
hp – horsepower
MMBTU/hr – million British Thermal Units (BTU) per hour

Table 1.3
Fort Wainwright Significant Emission Units for BACT Analysis

Emission Unit			Installation Date	Fuel Type	Rating	
Name	Description	Bldg. No.				
Distillate Fired Boilers						
		1171	N/A	Distillate	0.2	MMBTU/hr
		1172	N/A	Distillate	0.9	MMBTU/hr
		1172	N/A	Distillate	0.2	MMBTU/hr
		1185	N/A	Distillate	1.3	MMBTU/hr
		1185	N/A	Distillate	1.3	MMBTU/hr
		1191	N/A	Distillate	0.2	MMBTU/hr
		2092	N/A	Distillate	0.4	MMBTU/hr
		2092	N/A	Distillate	0.4	MMBTU/hr
		2096	N/A	Distillate	0.8	MMBTU/hr
		2096	N/A	Distillate	0.8	MMBTU/hr
		2400	N/A	Distillate	0.3	MMBTU/hr
		4076	N/A	Distillate	19.0	MMBTU/hr
		4076	N/A	Distillate	19.0	MMBTU/hr
		4076	N/A	Distillate	19.0	MMBTU/hr
		4321	N/A	Distillate	0.3	MMBTU/hr
		4322	N/A	Distillate	0.3	MMBTU/hr
		5003	N/A	Distillate	0.3	MMBTU/hr
		5007	N/A	Distillate	2.5	MMBTU/hr
		5008	N/A	Distillate	0.4	MMBTU/hr
		5009	N/A	Distillate	0.2	MMBTU/hr
		5010	N/A	Distillate	0.9	MMBTU/hr
		5109	N/A	Distillate	0.2	MMBTU/hr
		5110	N/A	Distillate	0.2	MMBTU/hr
		5113	N/A	Distillate	0.1	MMBTU/hr
		5119	N/A	Distillate	0.1	MMBTU/hr
		5175	N/A	Distillate	0.1	MMBTU/hr
		KDR	N/A	Distillate	0.1	MMBTU/hr
Waste Oil Boilers					43800.0	gal/yr

Table 1.3 (continued)
Fort Wainwright Significant Emission Units for BACT Analysis

Emission Unit			Installation Date	Fuel Type	Rating
Name	**Description**	**Bldg. No.**			
Emergency and Black Start Generators					
Black Start Generator Engine	Clarke DDFP-04AT	1572	1994	Distillate	235 hp
Generator Engine	Clarke DDFP-04AT	1572	1994	Distillate	235 hp
Generator Engine	Clarke DDFP-04AT	1572	1994	Distillate	235 hp
Generator Engine	Clarke DDFP-04AT	1572	1994	Distillate	235 hp
Generator Engine	CumminsN-855-F	2080	1977	Distillate	240 hp
Generator Engine	Cummins N-855-F	2080	1977	Distillate	240 hp
Generator Engine	Clarke JW64-UF30	2089	2007	Distillate	275 hp
Generator Engine	Cummins N-855-F	3011	1977	Distillate	240 hp
Generator Engine	Cummins N-855-F	3011	1977	Distillate	240 hp
Generator Engine	Cummins N-855-F	3011	1977	Distillate	240 hp
Generator Engine	Cummins N-855-F	3011	1977	Distillate	240 hp
Generator Engine	Clarke JU4H-UF40	3498	2005	Distillate	94 hp
Generator Engine	Clarke PDFP-06YT	5009	1996	Distillate	120 hp
Generator Engine	Clarke PDFP-06YT	5009	1996	Distillate	120 hp
Diesel Emergency Engine	Cummins QSB7-G3 NR3	Hangar	2012	Diesel	134 hp
Diesel Emergency Engine	John Deere 4024HF285B	1580	2009	Diesel	67 hp
Diesel Emergency Engine	CAT C9 GENSET	3406	2007	Diesel	335 hp
Diesel Emergency Engine	SDMO TM30UCM	3567	ND	Diesel	47 hp
Diesel Emergency Engine	Cat 3512	4076	2003	Diesel	1206 hp
Diesel Emergency Engine	Cat 3512	4076	2003	Diesel	1206 hp
Diesel Emergency Engine	Cat 3512	4076	2003	Diesel	1206 hp

Table 1.4
Doyon Utilities Insignificant Privatized Emission Units

Emission Unit(s)						
Description	**Make/ Model**	**Bldg. No.**	**Installation Date**	**Fuel Type**	**Rating**	
Material Handling Sources						
Fly and Bottom Ash Bin Vent Filter	United Conveyor Corp 96TB-BVT-25:S6	CHPP	1993	N/A	1,460	acfm
Ash Loadout to Truck	N/A	CHPP	Unknown	N/A	N/A	
Diesel Storage Tanks						
Aboveground Storage Tank	N/A	1002	2012	Diesel	80	gallons
Aboveground Storage Tank	N/A	1032	1993	Diesel	180	gallons
Aboveground Storage Tank	N/A	1054	2010	Diesel	278	gallons
Aboveground Storage Tank	N/A	1193	1990	Diesel	234	gallons
Aboveground Storage Tank	N/A	1554	1999	Diesel	1,500	gallons
Aboveground Storage Tank	N/A	1554	1999	Diesel	100	gallons
Aboveground Storage Tank	N/A	1563	2012	Diesel	100	gallons
Aboveground Storage Tank	N/A	1620	2008	Diesel	400	gallons
Aboveground Storage Tank	N/A	2088	2007	Diesel	114	gallons
Aboveground Storage Tank	N/A	2117	2006	Diesel	660	gallons
Aboveground Storage Tank	N/A	2117	2006	Diesel	450	gallons
Aboveground Storage Tank	N/A	2296	2005	Diesel	400	gallons
Aboveground Storage Tank	N/A	3004	2007	Diesel	60	gallons
Aboveground Storage Tank	N/A	3403	2012	Diesel	100	gallons
Aboveground Storage Tank	N/A	3405	1995	Diesel	500	gallons
Aboveground Storage Tank	N/A	3407	1994	Diesel	300	gallons
Aboveground Storage Tank	N/A	3563	1995	Diesel	275	gallons
Aboveground Storage Tank	N/A	3565	1997	Diesel	75	gallons
Aboveground Storage Tank	N/A	3587	2002	Diesel	180	gallons
Aboveground Storage Tank	N/A	3595	2009	Diesel	1,670	gallons
Aboveground Storage Tank	N/A	3598	Unknown	Diesel	1,000	gallons
Aboveground Storage Tank	N/A	3703	1989	Diesel	90	gallons
Aboveground Storage Tank	N/A	3724	2012	Diesel	100	gallons
Aboveground Storage Tank	N/A	4023	2009	Diesel	275	gallons
Aboveground Storage Tank	N/A	4162	2012	Diesel	100	gallons
Aboveground Storage Tank	N/A	4390	2010	Diesel	278	gallons
Diesel Underground Storage Tanks						
Underground Storage Tank	N/A	1056	1991	Diesel	1,000	gallons
Underground Storage Tank	N/A	1060	1991	Diesel	1,000	gallons
Underground Storage Tank	N/A	1563	1995	Diesel	1,000	gallons
Underground Storage Tank	N/A	1580	1994	Diesel	2,500	gallons
Underground Storage Tank	N/A	3407	1994	Diesel	1,000	gallons
Underground Storage Tank	N/A	3598	1991	Used oil/water	1,000	gallons

N/A Not applicable

Table 1.5
Fort Wainwright Insignificant Emission Units

Emission Unit(s)				
Description	**Make/Model**	**Bldg. No.**	**Fuel Type**	**Rating**
Aerospace Operations				
Aircraft Maintenance Hangers	Corrosion Prevention Compound	N/A	N/A	252.69 gallons/year
Aircraft Maintenance Hangers	Corrosion Prevention Compound	N/A	N/A	210.58 gallons/year
Aircraft Maintenance Hangers	3M Scotch-Weld Adhesive	N/A	N/A	1.05 gallons/year
Aircraft Maintenance Hangers	Loctite Adhesive Part A	N/A	N/A	0.85 gallons/year
Aircraft Maintenance Hangers	Loctite Adhesive Part B	N/A	N/A	4.21 gallons/year
Aircraft Maintenance Hangers	Antiseize Thread Compound	N/A	N/A	1.80 gallons/year
Aircraft Maintenance Hangers	Royco 634 Lubricant	N/A	N/A	0.13 gallons/year
Aircraft Maintenance Hangers	Coating Compound, Nonslip	N/A	N/A	294.81 gallons/year
Aircraft Maintenance Hangers	Corrosion Prevention Compound	N/A	N/A	0.54 gallons/year
Aircraft Maintenance Hangers	Epoxy Primer, Part A	N/A	N/A	1.05 gallons/year
Aircraft Maintenance Hangers	Epoxy Primer, Part B	N/A	N/A	4.21 gallons/year
Aircraft Maintenance Hangers	So-Sure Zinc Chromate Primer, Aerosol	N/A	N/A	0.47 gallons/year
Aircraft Maintenance Hangers	WS-8020 Class B-1/2 Curing Agent	N/A	N/A	0.53 gallons/year
Aircraft Maintenance Hangers	INSTAbond 146 Anaerobic Sealing	N/A	N/A	0.06 gallons/year
Aircraft Maintenance Hangers	WS-8020 Class B-1/2 Base	N/A	N/A	1.58 gallons/year
Aircraft Maintenance Hangers	Polyurethane Coating	N/A	N/A	737.02 gallons/year
Degreasing Operations				
Heavy Duty Industrial Degreaser	N/A	3015	N/A	694.90 gallons/year
Loctite Natural Blue Biodegradable	N/A	3018	N/A	42.12 gallons/year
Omni Biodegradable Degreaser	N/A	3018	N/A	2.11 gallons/year
Citratech, Citrus Cleaner	N/A	3018	N/A	189.52 gallons/year
Electron Dielectric Solvent	N/A	3475	N/A	202.15 gallons/year
Paradigm	N/A	3490	N/A	4.2 gallons/year
Fuel Dispensing				
Main Fuel Point	N/A	3484	Regular	12,000 gallons
Fuel Storage				
Underground Storage Tank	N/A	2096	Mogas	5,000 gallons
Underground Storage Tank	N/A	3015	Mogas	30,000 gallons
Underground Storage Tank	N/A	3484	JP-8	30,000 gallons
Underground Storage Tank	N/A	3484	JP-8	12,000 gallons
Aboveground Storage Tank	N/A	3484	Diesel	12,000 gallons
Aboveground Storage Tank	N/A	3484	Mogas	12,000 gallons
Underground Storage Tank	N/A	4065	Diesel	1,000 gallons
Underground Storage Tank	N/A	4109	Mogas	15,850 gallons
Aboveground Storage Tank	N/A	Bassett Hospital	Diesel	15,850 gallons
Aboveground Storage Tank	N/A	Bassett Hospital	Diesel	15,850 gallons
Aboveground Storage Tank	N/A	Bassett Hospital	Diesel	15,850 gallons
Aboveground Storage Tank	N/A	Bassett Hospital	Diesel	15,850 gallons

Table 1.5 (continued)
Fort Wainwright Insignificant Emission Units

Emission Unit(s)			Fuel Type	Rating
Description	**Make/Model**	**Bldg. No.**		
Aboveground Storage Tank	N/A	Bassett Hospital	Diesel	36,000 gallons
Aboveground Storage Tank	N/A	2078	JP-4	36,000 gallons
Aboveground Storage Tank	N/A	2078	JP-4	100 gallons
Aboveground Storage Tank	N/A	4065	Diesel	100 gallons
Aboveground Storage Tank	N/A	4065	Diesel	100 gallons
Aboveground Storage Tank	N/A	Bassett Hospital	Diesel	100 gallons
Aboveground Storage Tank	N/A	Bassett Hospital	Diesel	100 gallons
Aboveground Storage Tank	N/A	Bassett Hospital	Diesel	1,000 gallons
Underground Storage Tank	N/A	1171	Diesel	3,000 gallons
Underground Storage Tank	N/A	1172	FS1	8,000 gallons
Underground Storage Tank	N/A	1185	FS1	1,000 gallons
Aboveground Storage Tank	N/A	1191	Diesel	300 gallons
Aboveground Storage Tank	N/A	1572	Diesel	300 gallons
Aboveground Storage Tank	N/A	1572	Diesel	300 gallons
Aboveground Storage Tank	N/A	1572	Diesel	300 gallons
Aboveground Storage Tank	N/A	1572	Diesel	2,500 gallons
Underground Storage Tank	N/A	1580	Diesel	1,000 gallons
Underground Storage Tank	N/A	2062	FS1	1,000 gallons
Underground Storage Tank	N/A	2080	Diesel	3,000 gallons
Underground Storage Tank	N/A	2092	FS1	500 gallons
Underground Storage Tank	N/A	2096	Diesel	1,000 gallons
Underground Storage Tank	N/A	3011	Diesel	5,000 gallons
Underground Storage Tank	N/A	3015	Diesel	1,000 gallons
Underground Storage Tank	N/A	4321	FS1	1,000 gallons
Underground Storage Tank	N/A	4322	FS1	1,000 gallons
Underground Storage Tank	N/A	5003	FS1	5,000 gallons
Underground Storage Tank	N/A	5007	FS1	2,000 gallons
Underground Storage Tank	N/A	5008	FS1	2,000 gallons
Underground Storage Tank	N/A	5009	FS1	1,000 gallons
Aboveground Storage Tank	N/A	5009	Diesel	1,500 gallons
Underground Storage Tank	N/A	5010	FS1	1,000 gallons
Underground Storage Tank	N/A	5011	FS1	500 gallons
Aboveground Storage Tank	N/A	5108	Diesel	1,000 gallons
Underground Storage Tank	N/A	5110	FS1	N/A
Landfills				
FWA Landfill	N/A	N/A	N/A	N/A
Ozone Depleting Substances				
	N/A	3498	R-404A	11.00 lb refrigerant/year
	N/A	1044	R-404A	14.00 lb refrigerant/year
	N/A	3205	R-404A	6.50 lb refrigerant/year
	N/A	4024	R-404A	1.00 lb refrigerant/year
	N/A	3416	R-414	2.00 lb refrigerant/year
	N/A	1004	R-134	1.50 lb refrigerant/year
	N/A	3702	R-22	8.50 lb refrigerant/year
	N/A	1600	R-22	10.00 lb refrigerant/year
	N/A	3498	R-404A	22.00 lb refrigerant/year

Table 1.5 (continued)
Fort Wainwright Insignificant Emission Units

Emission Unit(s)			Fuel Type	Rating
Description	**Make/Model**	**Bldg. No.**		
	N/A	3025	R-22	5.00 lb refrigerant/year
	N/A	2092	R-402A	12.50 lb refrigerant/year
	N/A	3022	R-22	21.00 lb refrigerant/year
	N/A	1060	R-22	3.00 lb refrigerant/year
	N/A	2019	R-22	1.00 lb refrigerant/year
	N/A	D21004	R-22	21.50 lb refrigerant/year
	N/A	3703	R-22	25.00 lb refrigerant/year
	N/A	2116	R-22	4.00 lb refrigerant/year
	N/A	3704	R-22	7.00 lb refrigerant/year
	N/A	3407	R-22	3.50 lb refrigerant/year
	N/A	1580	R-22	10.50 lb refrigerant/year
	N/A	3416	R-414	2.00 lb refrigerant/year
	N/A	1580	R-22	12.00 lb refrigerant/year
	N/A	1044	R-402A	2.00 lb refrigerant/year
	N/A	3205	R-404A	3.00 lb refrigerant/year
	N/A	1060	R-22	3.50 lb refrigerant/year
	N/A	4320	R-22	11.50 lb refrigerant/year
	N/A	3416	R-22	5.00 lb refrigerant/year
	N/A	1044	R-22	8.00 lb refrigerant/year
	N/A	2116	R-22	4.00 lb refrigerant/year
	N/A	3015	R-134A	3.65 lb refrigerant/year
	N/A	1031	R-22	2.50 lb refrigerant/year
	N/A	3437	R-134	60.00 lb refrigerant/year
	N/A	1580	R-22	3.00 lb refrigerant/year
	N/A	3015	R-22	7.50 lb refrigerant/year
	N/A	3205	R-22	4.00 lb refrigerant/year
	N/A	3416	R-414	12.00 lb refrigerant/year
	N/A	4391	R-414	2.00 lb refrigerant/year
	N/A	1929	R-22	2.00 lb refrigerant/year
Surface Coatings				
	N/A	3015	Various	37 gallons/year
	N/A	3490	Various	280 gallons/year
Unpaved Roads				
Paved Roads				
Remediation				
Woodworking				
	N/A	5110	N/A	N/A

Table 1.6
Summary of Potential Emissions for Insignificant Emission Units

	Potential Emissions from Previous Permitting			
Ft. Wainwright Garrison Insignificant Sources	**NOx (TPY)**	**SO_2 (TPY)**	**VOC (TPY)**	**PM_{10}[1] (TPY)**
Aerospace Operations	N/A	N/A	2.01	N/A
Degreasing	N/A	N/A	3.85	N/A
Fuel Dispensing Station	N/A	N/A	0.66	N/A
Fuel Storage	N/A	N/A	3.48	N/A
Landfills	N/A	N/A	0.57	N/A
Ozone-Depleting Substances	N/A	N/A	0.16	N/A
Surface Coating	N/A	N/A	0.53	0.27
Waste Oil Boiler	0.42	6.44	0.02	0.34
Paved and Unpaved Roads	NA	NA	NA	18.12
Remediation	2.00	0.33	30.00	0.11
Woodworking	N/A	N/A	N/A	0.05
TOTAL EMISSIONS:	**2.42**	**6.76**	**41.28**	**18.89**
Doyon Utilities Insignificant Sources	**NOx (TPY)**	**SO_2 (TPY)**	**VOC (TPY)**	**PM2.5 (TPY)**
Fly and Bottom Ash Bin Vent Filter	0.00	0.00	0.00	18.98
Ash Loadout to Truck	0.00	0.00	0.00	0.00
Aboveground Storage Tanks	0.00	0.00	0.00	0.00
Underground Storage Tanks	0.00	0.00	0.00	0.00
TOTAL EMISSIONS:	**0.00**	**0.00**	**0.00**	**18.98**

[1] Particulate Matter (PM) with aerodynamic diameter of less than or equal to 10 microns (PM_{10}) and total PM emissions are assumed to be equal
N/A = not applicable to source
Doyon data from Table D2 as provided to Third Branch Engineering 3/27/17.
Ft. Wainwright data provided by Forms D1 and D2 Revised 080913 provided to Third Branch Engineering 3/17/17 (Fort Wainwright, 2013)

The Garrison's operations also include a Remediation site. During permitting activities for the Remediation site, the Garrison accepted a 30 ton/year VOC limit. The permit also requires monthly monitoring of VOC emissions. Monitoring data indicate zero VOC emissions from the Remediation activities. The BACT submittal will provide the documentation related to the calculation for VOC Potential to Emit to demonstrate that the Garrison and its Privatized Units are not subject to BACT for VOC.

APPENDIX A

ADEC CORRESPONDENCE ON FORT WAINWRIGHT BACT ANALYSIS

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THE STATE *of* ALASKA
GOVERNOR BILL WALKER

Department of Environmental Conservation

DIVISION OF AIR QUALITY
Director's Office

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April 24, 2015

Kathleen Hook
Environmental Program Manager
Doyon Utilities, LLC
PO Box 74040
Fairbanks, AK 99707

Subject: Voluntary BACT Analysis for Fort Wainwright (Privatized Emission Units)

Dear Ms. Hook:

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

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

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

<u>Background</u>

Clean Air

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

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

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

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

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

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

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

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

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

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

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

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

Sincerely,

Denise Koch, Director
Division of Air Quality

cc: Larry Hartig, ADEC/ Commissioner's Office
Alice Edwards, ADEC/ Commissioner's Office
John Kuterbach, ADEC/ Air Quality
Cindy Heil, ADEC/Air Quality
Deanna Huff, ADEC/ Air Quality
Eric Dick/U.S. Army (Fort Wainwright)

THE STATE
of ALASKA
GOVERNOR BILL WALKER

Department of Environmental Conservation

DIVISION OF AIR QUALITY
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Return Receipt Requested

February 3, 2016

Shayne Coiley, Senior Vice President
Doyon Utilities, LLC
714 Fourth Avenue, Suite 100
PO Box 74040
Fairbanks, Alaska 99707

Subject: Response to PM2.5 Serious Nonattainment BACT Analysis Protocol for the Fort Wainwright (Privatized Emission Units)

Dear Mr. Coiley:

Thank you for submitting your PM2.5 Serious Nonattainment BACT Analysis Protocol for the Fort Wainwright (Privatized Emission Units).

The clarifications you have requested are below:

1. ADEC plans to use 2013 as the baseline year for the Serious Area SIP. The EPA Region 10 is aware that ADEC has chosen this year. However, the year will not be final until EPA Region 10 formally approves the emission inventory and baseline year with the submittal of the Serious Area SIP. The baseline year could only be chosen from one of the last three years of the design value that caused the Fairbanks area to become a Serious Area (2013, 2014, or 2015).
2. ADEC has reviewed the protocol and has no comments. The EPA Region 10 has provided informal comments on the BACT protocol that was submitted, which are included below. As discussed during the Fort Wainwright monthly meeting call on December 23rd, 2015, this response letter took longer than the requested 30 days due to the holidays.
    a. The BACT analysis should be conducted for the permitted emission units and the following pollutants are above the 70 Potential To Emit (PTE) Tons Per Year (TPY) threshold according the AQ1121TVP02 permit: $PM_{2.5}$, SO_2 and NO_X.
    b. A Serious Area BACT analysis is only required for permitted emission units.
    c. EPA Region 10 reviewed the protocol and made comments, but they will not approve the BACT analysis until it has been officially submitted by ADEC. (See the excerpt from an email below.)

Clean Air

Shayne Coiley
Doyon Utilities, LLC

February 3, 2016
BACT Protocol Response

EPA Region 10 Response to the PM2.5 Serious Nonattainment BACT Analysis Protocol for the Fort Wainwright (Privatized Emission Units):

"EPA is providing informal comments to you on the BACT protocol provided by Fort Wainwright (Privatized Emission Units). At this time, we are not approving the protocol –we will formally review and approve the BACT analysis if/when it is submitted to us as part of the Serious Area Attainment Plan.

Below are some additional comments on the protocol document.

BACT Protocol

1. *Please clarify which emission units at the facility would not fall into the category of permitted emission units.*
2. *Section 1 – The BACT analysis will be evaluated with respect to EPA BACT guidance. The protocol needs to be consistent with that guidance - this protocol will not govern should any inconsistency be identified.*
3. *Section 1.5 – This section should clarify that all cost analyses will be conducted in accordance with the EPA Air Pollution Control Cost Manual.*
4. *Section 1.5 – The final sentence should be modified as follows "…if a particular control technology is eliminated based on economic factors, the assumption will be made that the control technology is also uneconomic for smaller emission units, provided that all other factors besides size are equivalent." This clarification is necessary because the reasoning only applies for emission units that are the same basic type of equipment, burn the same fuel, have similar retrofit challenges, etc.*
5. *Section 1.6 – Cost information must be emission unit specific. BACT cannot be determined using generic cost ranges.*
6. *Section 1.6 – Each BACT analysis must provide the basis for each input value and assumption used in the analysis and calculations. Electronic (pdf) copies of the actual documents forming the basis for each assumption should be provided. If the documents are publicly available on the internet, functional links to the information is acceptable.*
7. *Section 2 – The BACT analyses need to be conducted based on potential to emit (PTE), and EPA will verify the basis for the PTE values used for each emission unit and each pollutant. The BACT analysis should provide the basis and actual calculations used to derive each PTE value. It is acceptable to cite another document that forms the basis for the PTE, but these underlying documents must be included as attachments to the BACT analysis, and must themselves include sufficient detail in order to clearly illustrate the basis for the PTE values.*

Thank you again for submitting your BACT protocol for ADEC and EPA Region 10 review.
If you have any further questions in order to complete a timely BACT analysis, please contact Dea Huff, Ph.D. (deanna.huff@alaska.gov) or me.

Sincerely,

Denise Koch, Director
Division of Air Quality

Page **2** of **3**

cc: Cindy Heil, ADEC/Non-Point Mobile Sources
Deanna Huff, ADEC/Non-Point Mobile Sources
John Kuterbach, ADEC/Air Permits Program
Zeena Siddeek, ADEC/Air Permits Program
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Courtney Kimball, SLR - Fairbanks, (ckimball@slrconsulting.com)

APPENDIX B

BACT COST ESTIMATION TEMPLATES

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Table B-1
Example Total Capital Investment Determination

Capital Costs		
Direct Costs	***Cost Factors***	
(1) Purchased equipment and material costs		
(a) Basic equipment		=
(b) Instrumentation		=
(c) Freight		=
(d) Labor		=
(e) Startup Spares		=
(f) Vendor representatives' fees		=
Purchased Equipment and Materials Cost (PEMC)		=
(2) Direct Installation Costs		
(a) Concrete		=
(b) Piling		=
(c) Structural steel		=
(d) Electrical		=
(e) Painting		=
(f) Insulation		=
(g) Abovegrade piping		=
(h) Functional Checkouts		=
Direct Installation Costs (DIC)		=
Total Direct Costs (TDC)	(PEMC) + (DIC)	=
Indirect Costs		
(3) Engineering, Procurement & Construction Support Services		=
(4) Performance tests		=
Total Indirect Costs (TIC)		=
Management and Contingency Costs		
(5) UOC Costs		=
(6) Contingency		=
Total Management and Contingency Costs (TM&CC)		=
TOTAL CAPITAL INVESTMENT (TCI)	(TDC)+(TIC)+(TM&CC)	=

Table B-2
Example Cost Effectiveness Determination

Annualized Costs		
DIRECT ANNUAL COSTS	**Cost Factors**	
(1) Operating labor		=
(2) Supervisory labor		=
(3) Maintenance labor		=
(4) Maintenance materials		=
(5) Utilities		
Fuel:		=
Electricity:		=
Total Direct Annual Costs (TDAC)		=
INDIRECT ANNUAL COSTS		
(6) Overhead		=
(7) Administrative Charges		=
(8) Property tax		=
(9) Insurance		=
(10) Capital Recovery	(CRF*TCI)	=
Capital Recovery Factor (CRF) [7% ROR, 10-year life] is 0.1424		
Total Indirect Annual Costs (TIAC)		=
TOTAL ANNUALIZED COSTS (TAC)	**(TDAC) + (TIAC)**	=
Cost Effectiveness Summary		
TOTAL TONS AVOIDED PER YEAR		=
COST EFFECTIVENESS ($ PER TON AVOIDED)	**(TAC)/(TPY)**	=

APPENDIX C

EPA MEMORANDUM ON CALCULATING PTE FOR EMERGENCY GENERATORS

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September 6, 1995

MEMORANDUM

SUBJECT: Calculating Potential to Emit (PTE) for Emergency Generators

FROM: John S. Seitz, Director
Office of Air Quality Planning and Standards (MD-10)

TO: Director, Air, Pesticides and Toxics
Management Division, Regions I and IV
Director, Air and Waste Management Division,
Region II
Director, Air, Radiation and Toxics Division,
Region III
Director, Air and Radiation Division,
Region V
Director, Air, Pesticides and Toxics Division,
Region VI
Director, Air and Toxics Division,
Regions VII, VIII, IX, and X

The purpose of this guidance is to address the determination of PTE for emergency electrical generators.

Background

In a memorandum dated January 25, 1995, the Environmental Protection Agency (EPA) addressed a number of issues related to the determination of a source's PTE under section 112 and title V of the Clean Air Act (Act). One of the issues discussed in the memorandum was the term "maximum capacity of a stationary source to emit under its physical and operational design," which is part of the definition of "potential to emit." The memorandum clarified that inherent physical limitations, and operational design features which restrict the potential emissions of individual emission units, can be taken into account. This clarification was intended to address facilities for which the theoretical use of equipment is much higher than could ever actually occur in practice. For such facilities, if their physical limitations or operational design features are not taken into account, the potential emissions could be overestimated and consequently the source owner could be subject to the Act requirements affecting major sources. Although such source owners could in most cases readily accept enforceable limitations restricting the operation to its designed level, EPA believes this administrative requirement for such sources to be unnecessary and burdensome.

On the topic of "physical and operational design," the January 25 memorandum provided a general discussion. In addition, EPA committed to providing technical assistance on the type of inherent physical and operational design features that may be considered acceptable in determining the potential to emit for certain individual small source categories. The EPA is currently conducting category-specific analyses in support of this effort, and hopes as a result of these analyses to generate more general guidance on this issue as well.

The purpose of this memorandum is to address the issue of PTE as it relates specifically to emergency generators. There is a significant level of interest in this source category because there are many thousands of locations for which an emergency generator is the only emitting source. Moreover, based on a review of this source category, there exists a readily identifiable constraint on the operational design of emergency generators. Hence, the EPA believes it would be useful to provide today's guidance before the entire effort is complete.

The policies set forth in this memorandum are intended solely as guidance, do not represent final Agency action, and cannot be relied upon to create any rights enforceable by any party.

Guidance for Emergency Generators

For purposes of today's guidance, an "emergency generator" means a generator whose sole function is to provide back-up power when electric power from the local utility is interrupted. The emission source for such generators is typically a gasoline or diesel-fired engine, but can in some cases include a small gas turbine. Emissions consist primarily of carbon monoxide and nitrogen oxides. Other criteria pollutants, and hazardous air pollutants, are also emitted, but at much lower levels. Emissions occur only during emergency situations (i.e., where electric power from the local utility is interrupted), and for a very short time to perform maintenance checks and operator training.

The EPA believes that generators devoted to emergency uses are clearly constrained in their operation, in the sense that, by definition and design, they are used only during periods where electric power from public utilities is unavailable. Two factors indicate that this constraint is in fact "inherent." First, while the combined period for such power outages during any one year will vary somewhat, an upper bound can be estimated which would never be expected to be exceeded absent extraordinary circumstances. Second, the duration of these outages are entirely beyond the control of the source, and when they do occur (except in the case of a major catastrophe) rarely last more than a day.

For emergency generators, EPA has determined that a reasonable and realistic "worst-case" estimate of the number of hours that power would be expected to be unavailable from the local utility may be considered in identifying the "maximum capacity" of such generators for the purpose of estimating their PTE. Consequently, EPA does not recommend the use of 8760 hours per year (i.e., full-year operation) for calculating the PTE for emergency generators. Instead, EPA recommends that the potential to emit be determined based upon an estimate of the maximum amount of hours the generator could operate, taking into account (1) the number of hours power would be expected to be unavailable and (2) the number of hours for maintenance activities.

The EPA believes that 500 hours is an appropriate default assumption for estimating the number of hours that an emergency generator could be expected to operate under worst-case conditions. Alternative estimates can be made on a case-by-case basis where justified by the source owner or permitting authority (for example, if historical data on local power outages indicate that a larger or smaller number would be appropriate). Using the 500 hour default assumption, EPA has performed a number of calculations for some typically-sized emergency generators. These calculations indicate that these generators, in and of themselves, rarely emit at major source levels. (Of course, there may be unusual circumstances where these calculations would not be representative, for example where many generators are present that could operate simultaneously).

<u>Cautions</u>

Today's guidance is only meant to address emergency generators as described. Specifically, the guidance does not address: (1) peaking units at electric utilities; (2) generators at industrial facilities that typically operate at low rates, but are not confined to emergency purposes; and (3) any standby generator that is used during time periods when power is available from the utility. This guidance is also not intended to discourage permitting authorities from establishing operational limitations in construction permits when such limitations are deemed appropriate or necessary. Additionally, this memorandum is not intended to be used as the basis to rescind any such restrictions already in place.

Distribution/Further Information

The Regional Offices should send this memorandum to States within their jurisdiction. Questions concerning specific issues and cases should be directed to the appropriate Regional Office. Regional Office staff may contact Tim Smith of the Integrated Implementation Group at 919-541-4718. The document is also available on the technology transfer network (TTN) bulletin board, under "Clean Air Act" - "Title V" - "Policy Guidance Memos". (Readers unfamiliar with this bulletin board may obtain access by calling the TTN help line at 919-541-5384).

cc: Air Branch Chief, Region I-X
Regional Air Counsels, Region I-X
Adan Schwartz (2344)
Tim Smith (MD-12)

APPENDIX B

POTENTIAL TO EMIT CALCULATIONS

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BOILERS (Fuel Oil) - POTENTIAL EMISSIONS (Criteria PollutantsSubject to BACT) - Base Case

A. BACKGROUND INFORMATION **Source: Forms D1 and D2 Rev 080913 (Ft. Wainwright)**

Fuel Type: No. 1 Fuel Oil
Calculation Method: Emission Factors
Fuel Oil Sulfur Content (%S): 0.5

Source Classification Code (SCC):

	SCC
Commercial/Institutional Boilers (<10 MMBtu/hr) (Distillate Fuel Oil)	1-03-005-03

References: 1. AP-42, 5th Edition, Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources, May 2010
2. Alaska Department of Environmental Conservation Air Quality Permit AQ0236TVP02, 5 December 2008

Notes: Fuel oil sulfur content from Reference 2, Section 3, Requirement 13.1 (assumes all fuel oil burned by Fort Wainwright meets the same specification).
PTE for each of the 4076 back-up boilers is based on 200 hours of operation (or a third of the 600 hour ORL); heating value used is 137,000 Btu/gal.

B. EMISSION CALCULATION METHOD

Boiler Size	Emission Factor (lbs/1,000 gal)[1]		
	NO_x	SO_2[2]	PM_{10}
Distillate Oil-Fired Boilers (<10 MMBTU/hr)	20	71.0	1.08

[1] Reference 1, Tables 1.3-1, 1.3-3, 1.3-6, 1.3-12 [No. 1 (kerosene)]
[2] SO_2 emissions factor = 142S, where S = weight % sulfur and assumed at 0.5% for all boilers except the building 4076 boilers at the hospital, which are permit-limited to 0.3%.

Emission Calculation:
Emissions (lbs/yr) = Fuel Use (gal/yr) x Emission Factor (lbs/1,000 gal)

C. EMISSION SUMMARY

EU	Building Number	Boiler Capacity (MMBtu/hr)	Potential Fuel Use[1] (gal/yr)	Emissions (lbs/yr)		
				NO_x	SO_2	PM_{10}
8	4076	19.0	27,737	554.7	1,181.6	30.0
9	4076	19.0	27,737	554.7	1,181.6	30.0
10	4076	19.0	27,737	554.7	1,181.6	30.0
40	5007	2.6	162,686	3,253.7	11,550.7	175.7
		Significant Units Total (TPY)		**2.5**	**7.5**	**0.1**
	Emergency Boilers - assume 500 hours/year - Informational Only - These are Insignificant Sources within the Title V Permit.					
	5113	0.1	357	7.1	25.4	0.4
	5119	0.1	357	7.1	25.4	0.4
	5175	0.1	357	7.1	25.4	0.4
	KDR	0.1	357	7.1	25.4	0.4
	1171	0.2	714	14.3	50.7	0.8
	1172	0.2	714	14.3	50.7	0.8
	1191	0.2	714	14.3	50.7	0.8
	5009	0.2	714	14.3	50.7	0.8
	5109	0.2	714	14.3	50.7	0.8
	5110	0.2	714	14.3	50.7	0.8
	2400	0.3	1,071	21.4	76.1	1.2
	4321	0.3	1,071	21.4	76.1	1.2
	4322	0.3	1,071	21.4	76.1	1.2
	5003	0.3	1,071	21.4	76.1	1.2
	2092	0.4	1,429	28.6	101.4	1.5
	2092	0.4	1,429	28.6	101.4	1.5
	5008	0.4	1,429	28.6	101.4	1.5
	2096	0.8	2,857	57.1	202.9	3.1
	2096	0.8	2,857	57.1	202.9	3.1
	1172	0.9	3,214	64.3	228.2	3.5
	5010	0.9	3,214	64.3	228.2	3.5
	1185	1.3	4,643	92.9	329.6	5.0
	1185	1.3	4,643	92.9	329.6	5.0
		Insignficant Unit Totals (TPY)		**0.4**	**1.3**	**0.0**
	TOTAL EMISSIONS (TPY)			**2.82**	**8.82**	**0.15**

[1] Potential Fuel Use is derived from boiler heat input rating as Boiler Rating BTU/hr X 8760 hr/140000 BTU/gal.
boiler/ 137000 BTU/gallon/3 boilers = 27,737 gallons per boiler

INTERNAL COMBUSTION ENGINES - POTENTIAL EMISSIONS (Criteria Pollutants Subject to BACT)

A. BACKGROUND INFORMATION

Source: Forms D1 and D2 Revised 080913 (Ft. Wainwright)

Calculation Method: Emission Factors
Fuel Used: #1 Fuel Oil

Source Classification Code (SCC):

Internal Combustion Engines	SCC
Diesel Internal Combustion Engines < 447 kW (600 hp)	2-03-001-01

Reference AP-42, 5th Edition, Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources, October 1996

Notes: Potential to emit is based on 500 hour limit in USEPA Memorandum, September 6, 1995, "Calculating Potential to Emit (PTE) for Emergency Generators"

Building 2089 - John Deere Engine - Manufacturer information used

B. EMISSION CALCULATION METHOD

Emission Factors for Uncontrolled Diesel Industrial Engines [Power Output (lb/hp-hr)][1]

				NO_x	SO_2	PM_{10}
John Deere 2089 Engine (g/hp-hr)				7.4		0.16
Internal Combustion Engines < or = 447 kW (600 hp)				3.10E-02	2.05E-03	2.20E-03

[1]Reference, Table 3.3-1

Emission Calculation:
Emissions (lbs/yr) = Engine Rating (hp) x Operating Hours (hr/yr) x Emission Factor (lb/hp-hr)

C. EMISSION SUMMARY

EU	Building Number	Manufacturer	Manufacturer Year	Model Number	Engine Rating (hp)	Operating Hours (hr/yr)	Emissions (lbs/yr) NO_x	Emissions (lbs/yr) SO_2	Emissions (lbs/yr) PM_{10} [a]
31	1572	Clarke	1994	DDFP-04AT	235	500	3,642.5	240.9	258.5
32	1572	Clarke	1994	DDFP-04AT	235	500	3,642.5	240.9	258.5
33	1572	Clarke	1994	DDFP-04AT	235	500	3,642.5	240.9	258.5
34	1572	Clarke	1994	DDFP-04AT	235	500	3,642.5	240.9	258.5
35	2080	Cummins	1977	N-855-F	240	500	3,720.0	246.0	264.0
36	2080	Cummins	1977	N-855-F	240	500	3,720.0	246.0	264.0
30	2089	John Deere	2007	JW64-UF30	275	500	2,238.5	281.9	48.4
37	3498	Clarke	2005	JU4H-UF40	94	500	1,457.0	96.4	103.4
38	5009	Clarke	1996	PDFP-06YT	120	500	1,860.0	123.0	132.0
39	5009	Clarke	1996	PDFP-06YT	120	500	1,860.0	123.0	132.0
	TOTAL EMISSIONS (lbs/yr)						**29,425.5**	**2,079.7**	**1,977.8**
	TOTAL EMISSIONS (TPY)						**14.71**	**1.04**	**0.99**

[a] $PM_{2.5}$ is assumed to equal PM_{10}.

INTERNAL COMBUSTION ENGINES - POTENTIAL EMISSIONS (Criteria Pollutants Subject to BACT)

A. BACKGROUND INFORMATION

Emission Year: 2012
Calculation Method: Emission Factors Source: Forms D1 and D2 Revised 080913
Fuel Used: #1 Fuel Oil

Source Classification Code (SCC):

Internal Combustion Engines	SCC
Diesel Internal Combustion Engines > 447 kW (600 hp)	2-03-001-01
Diesel Internal Combustion Engines < 447 kW (600 hp)	2-03-001-01

Notes: Potential to emit hours were derived from the following:(a) 500 hour limit in USEPA Memorandum, September 6, 1995, "Calculating Potentia to Emit (PTE) for Emergency Generators", and (b) 600 hour limit in current operating permit AQ0236TVP02 for Emission Units 11, 12, and 13 combined -- assumed 200 hours each.

B. EMISSION CALCULATION METHOD

Non Certified Engines (Emission factors in g/hp-hr)
Cat 3512 -

	NO_x	SO_2	PM
Cat 3512	9.41E+00		1.44E-01

(Emission factors in g/kW-hr, NOX is conservative as emission factor is Nox+NMHC)

	Nox+HC	SO_2	PM
John Deere 4024HF285B, Tier 3	4.70E+00		4.00E-01
Cummins QSB7-G3 NR3 - Certified Engine (g/hp-hr)	4.00E+00		2.00E-02
Cat C9, Tier 3	4.00E+00		2.00E-01

Conversion from hp to Kw **1 horsepower** **0.7457** **kW**

Emission Factors for Uncontrolled Diesel Industrial Engines [Power Output (lb/hp-hr)][1]

	NO_x	SO_2	PM_{10}
Internal Combustion Engines > 447 kW (600 hp)	2.40E-02	8.09E-03	4.00E-04
Internal Combustion Engines < or = 447 kW (600 hp)	3.10E-02	2.05E-03	2.20E-03

[1]Reference 1, Tables 3.3-1, 3.4-1 and 3.4-2.
Reference AP-42, 5th Edition, Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources, October 199

Emission Calculation:
Emissions (lbs/yr) = Engine Rating (hp) x Operating Hours (hr/yr) x Emission Factor (g/hp/hr) x (kg/1000 g) * (2.2 lb/kg)
Emissions (lbs/yr) = Engine Rating (hp) x Operating Hours (hr/yr) x Emission Factor (g/kw-hr) X (0.7457 kw/hp) * (kg/1000 g) * (2.2 lb/kg
Emissions (lbs/yr) = Engine Rating (hp) x Operating Hours (hr/yr) x Emission Factor (lb/hp-hr)

C. EMISSION SUMMARY

EU ID	Building Number	Manufacturer	Manufacturer Year	Model Number	Engine Rating (hp)	Operating Hours (hr/yr)	Emissions (lbs/yr) NO_x	SO_2	PM_{10} [a]
26	Hangar	Cummins	2012	QSB7-G3 NR3	295	500	967.9	302.4	3.6
27	1580	John Deere	2009	4024HF285B	67	500	258.3	68.7	22.0
28	3406	Caterpillar	2007	CAT C9 GENSET	398	500	1,305.9	408.0	65.3
29	3567	SDMO	ND	TM30UCM	47	500	728.5	48.2	51.7
11	4076, Bassett Hospital	Caterpillar	2003	3512	1454	200	6,022.0	2,352.6	92.0
12	4076, Bassett Hospital	Caterpillar	2003	3512	1454	200	6,022.0	2,352.6	92.0
13	4076, Bassett Hospital	Caterpillar	2003	3512	1454	200	6,022.0	2,352.6	92.0
	TOTAL EMISSIONS (lbs/yr)						**21,326.6**	**7,884.9**	**418.6**
	TOTAL EMISSIONS (TPY)						**10.66**	**3.94**	**0.21**

[a] $PM_{2.5}$ is assumed to equal PM_{10}.

WASTE OIL BOILER - POTENTIAL EMISSIONS (Criteria Pollutants Subject to BACT Review)

A. BACKGROUND INFORMATION

Document Source: Forms D1 and D2 revised 080913

Calculation Method: Emission Factors
Fuel Used: Waste oils

Source Classification Code (SCC)

	SCC
External Combustion, Waste Oil, Small Boiler	1-03-013-02

Reference: 1. AP-42, 5th Edition, Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources, October 1996
2. PI-02F Instructions, "Process Information: Combustion - Instructions", Indiana Department of Environmental Management, Office of Air Quality, October 2006.

Notes: Potential fuel use is calculated by nameplate fuel use rating (2.5 gal/hr) X 8760 hours per year X 2 units = 43,800 gal/year combined use.

B. EMISSION CALCULATION METHOD

Emission factors for waste oil combustors (lbs/1000 gal) [1]

	NO_x	SO_X [2,4]	PM_{10} [3,4]
Waste oil combustors, Small boilers	19.00	294.00	15.30

[1] Reference 1, Tables 1.11-1, 1.11-2, 1.11-3
[2] SO_x emissions factor = 147S, where S = weight % sulfur: 147 X 2.0 = 294
[3] PM_{10} emissions factor = 51A, where A = weight % ash: 51 X 0.3 = 15.3
[4] Reference 2, Part C. Default value for S = 2.0 and for A = 0.3

Emission Calculation:
Emissions (lbs/yr) = Emission Factor (lbs/1,000 gal) x Fuel Used (gal/yr)

C. EMISSION SUMMARY

Unit	Fuel Used (gals/yr)	NO_x	SO_x	PM_{10} [a]
Waste Oil Combustor, Small Boilers, Building 3476	43,800	832.2	12,877.2	
TOTAL EMISSIONS (lbs/yr)		**832.2**	**12,877.2**	**0.0**
TOTAL EMISSIONS (TPY)		**0.42**	**6.44**	**<0.01**

[a] $PM_{2.5}$ is assumed to equal PM_{10}.

Oxides of Nitrogen (NO_X) Emissions - Base Case
Doyon Utilities - Fort Wainwright (Privatized Emission Units)

Emission Unit		Fuel	Factor	NO_X Emission	Emission Unit	Allowable Annual	Potential
ID	Description	Type	Reference	Factor	Rating/Capacity	Operation	NO_X Emissions
Significant Emission Units							
1	Coal-Fired Boiler 3	Coal	AP-42, Table 1.1-3	8.8 lb/ton	230 MMBtu/hr	336,000 tpy	1,478 tpy
2	Coal-Fired Boiler 4	Coal	AP-42, Table 1.1-3	8.8 lb/ton	230 MMBtu/hr		
3	Coal-Fired Boiler 5	Coal	AP-42, Table 1.1-3	8.8 lb/ton	230 MMBtu/hr		
4	Coal-Fired Boiler 6	Coal	AP-42, Table 1.1-3	8.8 lb/ton	230 MMBtu/hr		
5	Coal-Fired Boiler 7	Coal	AP-42, Table 1.1-3	8.8 lb/ton	230 MMBtu/hr		
6	Coal-Fired Boiler 8	Coal	AP-42, Table 1.1-3	8.8 lb/ton	230 MMBtu/hr		
7a	South Coal Handling Dust Collector (DC-01)	N/A	N/A	N /A	13,150 acfm	2,195 hr/yr	0 tpy
7b	South Underbunker Dust Collector (DC-02)	N/A	N/A	N /A	884 acfm	100 hr/yr	0 tpy
7c	North Coal Handling Dust Collector (NDC-1)	N/A	N/A	N /A	9,250 acfm	45 hr/yr	0 tpy
8	Backup Generator Engine	Distillate	Vendor	5.39 g/hp-hr	2,937 hp	500 hr/yr	8.7 tpy
9	Generator Engine	Distillate	AP-42, Table 3.3-1	0.031 lb/hp-hr	353 hp	500 hr/yr	2.73 tpy
10	Generator Engine	Distillate	AP-42, Table 3.4-1	0.024 lb/hp-hr	762 hp	500 hr/yr	4.57 tpy
11	Generator Engine	Distillate	AP-42, Table 3.4-1	0.024 lb/hp-hr	762 hp	500 hr/yr	4.57 tpy
12	Generator Engine	Distillate	AP-42, Table 3.3-1	0.031 lb/hp-hr	82 hp	500 hr/yr	0.64 tpy
13	Generator Engine	Distillate	AP-42, Table 3.3-1	0.031 lb/hp-hr	587 hp	500 hr/yr	4.55 tpy
14	Generator Engine	Distillate	AP-42, Table 3.3-1	0.031 lb/hp-hr	320 hp	500 hr/yr	2.48 tpy
15	Generator Engine	Distillate	AP-42, Table 3.4-1	0.024 lb/hp-hr	1,059 hp	500 hr/yr	6.35 tpy
16	Generator Engine	Distillate	AP-42, Table 3.3-1	0.031 lb/hp-hr	212 hp	500 hr/yr	1.64 tpy
17	Generator Engine	Distillate	AP-42, Table 3.3-1	0.031 lb/hp-hr	176 hp	500 hr/yr	1.37 tpy
18	Generator Engine	Distillate	AP-42, Table 3.3-1	0.031 lb/hp-hr	212 hp	500 hr/yr	1.64 tpy
19	Generator Engine	Distillate	AP-42, Table 3.3-1	0.031 lb/hp-hr	71 hp	500 hr/yr	0.55 tpy
20	Generator Engine	Distillate	AP-42, Table 3.3-1	0.031 lb/hp-hr	35 hp	500 hr/yr	0.27 tpy
21	Generator Engine	Distillate	AP-42, Table 3.3-1	0.031 lb/hp-hr	95 hp	500 hr/yr	0.74 tpy
22	Generator Engine	Distillate	AP-42, Table 3.3-1	0.031 lb/hp-hr	35 hp	500 hr/yr	0.27 tpy
23	Generator Engine	Distillate	AP-42, Table 3.3-1	0.031 lb/hp-hr	155 hp	500 hr/yr	1.20 tpy
24	Generator Engine	Distillate	AP-42, Table 3.3-1	0.031 lb/hp-hr	50 hp	500 hr/yr	0.39 tpy
25	Generator Engine	Distillate	AP-42, Table 3.3-1	0.031 lb/hp-hr	18 hp	500 hr/yr	0.14 tpy
26	Generator Engine	Distillate	AP-42, Table 3.3-1	0.031 lb/hp-hr	68 hp	500 hr/yr	0.53 tpy
27	Generator Engine	Distillate	AP-42, Table 3.3-1	0.031 lb/hp-hr	274 hp	500 hr/yr	2.12 tpy
28	Generator Engine	Distillate	AP-42, Table 3.3-1	0.031 lb/hp-hr	274 hp	500 hr/yr	2.12 tpy
29a	Lift Pump Engine	Distillate	AP-42, Table 3.3-1	0.031 lb/hp-hr	74 hp	500 hr/yr	0.57 tpy
30	Lift Pump Engine	Distillate	AP-42, Table 3.3-1	0.031 lb/hp-hr	75 hp	500 hr/yr	0.58 tpy
31a	Lift Pump Engine	Distillate	AP-42, Table 3.3-1	0.031 lb/hp-hr	74 hp	500 hr/yr	0.57 tpy
32	Lift Pump Engine	Distillate	AP-42, Table 3.3-1	0.031 lb/hp-hr	75 hp	200 hr/yr	0.23 tpy
33	Lift Pump Engine	Distillate	AP-42, Table 3.3-1	0.031 lb/hp-hr	75 hp	500 hr/yr	0.58 tpy
34	Well Pump Engine	Distillate	AP-42, Table 3.3-1	0.031 lb/hp-hr	220 hp	500 hr/yr	1.71 tpy
35	Well Pump Engine	Distillate	AP-42, Table 3.3-1	0.031 lb/hp-hr	55 hp	500 hr/yr	0.43 tpy
36	Well Pump Engine	Distillate	AP-42, Table 3.3-1	0.031 lb/hp-hr	220 hp	500 hr/yr	1.71 tpy
51a	Fly Ash Dust Collector (DC-1)	N/A	N/A	N/A	3,620 acfm	4,380 hr/yr	0 tpy
51b	Bottom Ash Dust Collector (DC-2)	N/A	N/A	N/A	3,620 acfm	4,380 hr/yr	0 tpy
52	Coal Storage Pile	N/A	N/A	N/A	N/A	82,049 tpy	0 tpy
Significant Emission Units Total Assessable Potential to Emit - NO_X							**1,532.4 tpy**
Insignificant Emission Units							
N/A	Fly and Bottom Ash Bin Vent Filter	N/A	N/A	N/A	1,460 acfm	4,380 hr/yr	0 tpy
N/A	Ash Loadout to Truck	N/A	N/A	N/A	N/A	28,560 tpy	0 tpy
N/A	Aboveground Storage Tanks	Diesel	N/A	N/A	N/A	N/A	0 tpy
N/A	Underground Storage Tanks	Diesel	N/A	N/A	N/A	N/A	0 tpy
Insignificant Emission Units Total Assessable Potential to Emit - NO_X							**0 tpy**
Total Assessable Potential to Emit - NO_X							**1,532.4 tpy**

Conversion factors:

Weight	453.6	g/lb
Weight	2,000	lb/ton

Source: Doyon Title V Renewal Permit Application, D-1.5, May 2013

Revised Oxides of Nitrogen (NO_X) Emissions - Proposed
Doyon Utilities - Fort Wainwright (Privatized Emission Units)

Emission Unit				Fuel	Factor	NO_X Emission	Emission Unit	Allowable Annual	Potential
ID	Description	Type of Service	Installation Date	Type	Reference	Factor	Max Rating/Capacity	Operation	NO_X Emissions
				Significant Emission Units					
1	Coal-Fired Boiler 3		1953	Coal	AP-42 Table 1.1.3 with 25% control assumed by OFA and OT per table 1.1.2 (9/98).	6.6 lb/ton	230 MMBtu/hr		
2	Coal-Fired Boiler 4		1953	Coal		6.6 lb/ton	230 MMBtu/hr		
3	Coal-Fired Boiler 5		1953	Coal		6.6 lb/ton	230 MMBtu/hr	300,000 ton/year	990.0 tpy
4	Coal-Fired Boiler 6		1953	Coal		6.6 lb/ton	230 MMBtu/hr		
5	Coal-Fired Boiler 7		1953	Coal		6.6 lb/ton	230 MMBtu/hr		
6	Coal-Fired Boiler 8		1953	Coal		6.6 lb/ton	230 MMBtu/hr		
7a	South Coal Handling Dust Collector (DC-01)		2001	N/A	N/A	N /A	13,150 acfm	2,195 hr/yr	0 tpy
7b	South Underbunker Dust Collector (DC-02)		2005	N/A	N/A	N /A	884 acfm	100 hr/yr	0 tpy
7c	North Coal Handling Dust Collector (NDC-1)		2004	N/A	N/A	N /A	9,250 acfm	45 hr/yr	0 tpy
8	Caterpillar 3516C	Backup Generator Engine	2009	Distillate	Vendor	5.39 g/kw-hr	2,937 hp	500 hr/yr	8.7 tpy
9	Detroit 6V92	Generator Engine	1988	Distillate	AP-42, Table 3.3-1	0.031 lb/hp-hr	353 hp	500 hr/yr	0.0 tpy
10	Caterpillar C15	Generator Engine	2010	Distillate	Certified Engine	6.4 g/kw-hr	762 hp	500 hr/yr	2.0 tpy
11	Caterpillar C15	Generator Engine	2010	Distillate	Certified Engine	6.4 g/kw-hr	762 hp	500 hr/yr	2.0 tpy
12	Cummins B3.3; SN 68011380	Generator Engine	2002	Distillate	AP-42, Table 3.3-1	0.031 lb/hp-hr	82 hp	500 hr/yr	0.6 tpy
13	Caterpillar 3406C TA; SN 4ZR04910	Generator Engine	2008	Distillate	Certified Engine	4 g/kw-hr	587 hp	500 hr/yr	1.0 tpy
14	Cummins QSL-G2 NR3	Generator Engine	2008	Distillate	Certified Engine	4 g/kw-hr	320 hp	500 hr/yr	0.5 tpy
15	Detroit R1237M36; SN 5352004032	Generator Engine	2005	Distillate	Mfg Information	5.75 g/hp-hr	1,059 hp	500 hr/yr	3.3 tpy
16	John Deere 6068TF250; SN PE6068T440136	Generator Engine	2005	Distillate	AP-42, Table 3.3-1	0.031 lb/hp-hr	212 hp	500 hr/yr	1.6 tpy
17	John Deere 6068TF250	Generator Engine	2007	Distillate	Permit condition 23.1c	6.9 g/hp-hr	176 hp	500 hr/yr	0.7 tpy
18	John Deere 6068HF150; SN PE6068H46179	Generator Engine	2005	Distillate	AP-42, Table 3.3-1	0.031 lb/hp-hr	212 hp	500 hr/yr	1.6 tpy
19	John Deere 4045TF270	Generator Engine	2007	Distillate	Certified Engine	7.5 g/kw-hr	71 hp	500 hr/yr	0.2 tpy
20	John Deere 4239D; SN T04239D226632	Generator Engine	1976	Distillate	AP-42, Table 3.3-1	0.031 lb/hp-hr	35 hp	500 hr/yr	0.3 tpy
21	Perkins 2046/1800; SN AK50724	Generator Engine	2001	Distillate	AP-42, Table 3.3-1	0.031 lb/hp-hr	95 hp	500 hr/yr	0.7 tpy
22	Cummins	Generator Engine	1989	Distillate	AP-42, Table 3.3-1	0.031 lb/hp-hr	35 hp	500 hr/yr	0.3 tpy
23	John Deere 6068HF150; SN PE6068H221858	Generator Engine	2003	Distillate	AP-42, Table 3.3-1	0.031 lb/hp-hr	155 hp	500 hr/yr	1.2 tpy
24	Cummins L634D-I/10386E; SN 53112605	Generator Engine	1993	Distillate	AP-42, Table 3.3-1	0.031 lb/hp-hr	50 hp	500 hr/yr	0.4 tpy
25	Caterpillar C1.5	Generator Engine	2011	Distillate	Certified Engine	7.5 g/kw-hr	18 hp	500 hr/yr	0.1 tpy
26	Cummins 4B3.9-G2: SN 46319490	Generator Engine	2003	Distillate	AP-42, Table 3.3-1	0.031 lb/hp-hr	68 hp	500 hr/yr	0.5 tpy
27	Caterpillar C6.6	Generator Engine	2010	Distillate	Certified Engine	4 g/kw-hr	274 hp	500 hr/yr	0.4 tpy
28	Caterpillar C6.6	Generator Engine	2010	Distillate	Certified Engine	4 g/kw-hr	274 hp	500 hr/yr	0.4 tpy
29a	John Deere 4045TF290	Lift Pump Engine	2014	Distillate	Certified Engine	4.7 g/kW-hr	74 hp	500 hr/yr	0.1 tpy
30	Detroit Diesel 10245100	Lift Pump Engine	1952	Distillate	AP-42, Table 3.3-1	0.031 lb/hp-hr	75 hp	500 hr/yr	0.6 tpy
31a	John Deere 4045TF290	Lift Pump Engine	2014	Distillate	Certified Engine	4.7 g/kW-hr	74 hp	500 hr/yr	0.1 tpy
32	Perkins	Lift Pump Engine	1955	Distillate	AP-42, Table 3.3-1	0.031 lb/hp-hr	75 hp	500 hr/yr	0.6 tpy
33	Perkins	Lift Pump Engine	1994	Distillate	AP-42, Table 3.3-1	0.031 lb/hp-hr	75 hp	500 hr/yr	0.6 tpy
34	Detroit Diesel 10447000	Well Pump Engine	1995	Distillate	AP-42, Table 3.3-1	0.031 lb/hp-hr	220 hp	500 hr/yr	1.7 tpy
35	John Deere 4045DF120	Well Pump Engine	2009	Distillate	Certified Engine	7.8 g/hp-hr	55 hp	500 hr/yr	0.2 tpy
36	Detroit Diesel 4031-C	Well Pump Engine	1995	Distillate	AP-42, Table 3.3-1	0.031 lb/hp-hr	220 hp	500 hr/yr	1.7 tpy
51a	Fly Ash Dust Collector (DC-1)		1993	N/A	N/A	N/A	3,620 acfm	4,380 hr/yr	0 tpy
51b	Bottom Ash Dust Collector (DC-2)		1994	N/A	N/A	N/A	3,620 acfm	4,380 hr/yr	0 tpy
52	Coal Storage Pile		UNK	N/A	N/A	N/A	N/A	82,049 tpy	0 tpy
								Significant Emission Units Potential to Emit - NO_X	**1,022.4 tpy**
				Insignificant Emission Units					
52	Fly and Bottom Ash Bin Vent Filter			N/A	N/A	N/A	1,460 acfm	4,380 hr/yr	0 tpy
52	Ash Loadout to Truck			N/A	N/A	N/A	N/A	28,560 tpy	0 tpy
52	Aboveground Storage Tanks			Diesel	N/A	N/A	N/A	N/A	0 tpy
52	Underground Storage Tanks			Diesel	N/A	N/A	N/A	N/A	0 tpy
								Insignificant Emission Units Potential to Emit - NO_X	**0 tpy**
								Total Potential to Emit - NO_X	**1,022.4 tpy**

Conversio 1 hp		Conversion factors:	0.7457 kW	
	Weight		453.6 g/lb	
	Weight		2,000 lb/ton	
	Coal Heating Value		15.1 MMBtu/ton	*From www.usibelli.com/Coal_data.php*

Source: Doyon Title V Renewal Permit Application, D-1.5

Location	EU	Make	Description	Year	Status	Size (hp)	Annual Operating Limits (non-Emergency)	Proposed BACT
DU	8	Caterpillar 3516C	Backup Generator Engine	2009	Certified Engine	2,937	500	Comply with 40 CFR 60 Subpart IIII
DU	9	Detroit 6V92	Generator Engine	1988		353	500	Limit fuel to ULSD.
DU	10	Caterpillar C15	Generator Engine	2010	Certified Engine	762	500	Comply with 40 CFR 60 Subpart IIII
DU	11	Caterpillar C15	Generator Engine	2010	Certified Engine	762	500	Comply with 40 CFR 60 Subpart IIII
DU	12	Cummins B3.3	Generator Engine	2002		82	500	Limit fuel to ULSD.
DU	13	Caterpillar 3406C TA	Generator Engine	2008	Certified Engine	587	500	Comply with 40 CFR 60 Subpart IIII
DU	14	Cummins QSL-G2 NR3	Generator Engine	2008	Certified Engine	320	500	Comply with 40 CFR 60 Subpart IIII
DU	15	Detroit R1237M36	Generator Engine	2005	Mfg Information	1,059	500	Limit fuel to ULSD.
DU	16	John Deere 6068TF250	Generator Engine	2005		212	500	Limit fuel to ULSD.
DU	17	John Deere 6068TF250	Generator Engine	2007	Permit condition 23.1c	176	500	Limit fuel to ULSD.
DU	18	John Deere 6068HF150	Generator Engine	2005		212	500	Limit fuel to ULSD.
DU	19	John Deere 4045TF270	Generator Engine	2007	Certified Engine	71	500	Comply with 40 CFR 60 Subpart IIII
DU	20	John Deere 4239D	Generator Engine	1976		35	500	Limit fuel to ULSD.
DU	21	Perkins 2046/1800	Generator Engine	2001		95	500	Limit fuel to ULSD.
DU	22	Cummins	Generator Engine	1989		35	500	Limit fuel to ULSD.
DU	23	John Deere 6068HF150	Generator Engine	2003		155	500	Limit fuel to ULSD.
DU	24	Cummins L634D-I/10386E	Generator Engine	1993		50	500	Limit fuel to ULSD.
DU	25	Caterpillar C1.5	Generator Engine	2011	Certified Engine	18	500	Comply with 40 CFR 60 Subpart IIII
DU	26	Cummins 4B3.9-G2	Generator Engine	2003		68	500	Limit fuel to ULSD.
DU	27	Caterpillar C6.6	Generator Engine	2010	Certified Engine	274	500	Comply with 40 CFR 60 Subpart IIII
DU	28	Caterpillar C6.6	Generator Engine	2010	Certified Engine	274	500	Comply with 40 CFR 60 Subpart IIII
DU	30	Detroit Diesel 10245100	Lift Pump Engine	1952		75	500	Limit fuel to ULSD.
DU	32	Perkins	Lift Pump Engine	1955		75	500	Limit fuel to ULSD.
DU	33	Perkins	Lift Pump Engine	1994		75	500	Limit fuel to ULSD.
DU	34	Detroit Diesel 10447000	Well Pump Engine	1995		220	500	Limit fuel to ULSD.
DU	35	John Deere 4045DF120	Well Pump Engine	2009	Certified Engine	55	500	Comply with 40 CFR 60 Subpart IIII
DU	36	Detroit Diesel 4031-C	Well Pump Engine	1995		220	500	Limit fuel to ULSD.
DU	29a	John Deere 4045TF290	Lift Pump Engine	2014	Certified Engine	74	500	Comply with 40 CFR 60 Subpart IIII
DU	31a	John Deere 4045TF290	Lift Pump Engine	2014	Certified Engine	74	500	Comply with 40 CFR 60 Subpart IIII
FWA	11	Caterpillar	3512	2003		1454	200	Owner Requested Limit of 600 hours/12-month period cumulative for these three engines.
FWA	12	Caterpillar	3512	2003		1454	200	
FWA	13	Caterpillar	3512	2003		1454	200	
FWA	26	Cummins	QSB7-G3 NR3	2012	Certified Engine	295	500	Comply with 40 CFR 60 Subpart IIII
FWA	27	John Deere	4024HF285B	2009	Certified Engine	67	500	Comply with 40 CFR 60 Subpart IIII
FWA	28	Caterpillar	CAT C9 GENSET	2007	Certified Engine	398	500	Comply with 40 CFR 60 Subpart IIII
FWA	29	SDMO	TM30UCM	ND		47	500	Limit fuel to ULSD.
FWA	30	John Deere	JW64-UF30	2007	Certified Engine	275	500	Comply with 40 CFR 60 Subpart IIII
FWA	31	Clarke	DDFP-04AT	1994		235	500	Limit fuel to ULSD.
FWA	32	Clarke	DDFP-04AT	1994		235	500	Limit fuel to ULSD.
FWA	33	Clarke	DDFP-04AT	1994		235	500	Limit fuel to ULSD.
FWA	34	Clarke	DDFP-04AT	1994		235	500	Limit fuel to ULSD.
FWA	35	Cummins	N-855-F	1977		240	500	Limit fuel to ULSD.
FWA	36	Cummins	N-855-F	1977		240	500	Limit fuel to ULSD.
FWA	37	Clarke	JU4H-UF40	2005		94	500	Limit fuel to ULSD.
FWA	38	Clarke	PDFP-06YT	1996		120	500	Limit fuel to ULSD.
FWA	39	Clarke	PDFP-06YT	1996		120	500	Limit fuel to ULSD.

Make	Description	Year	Status			Size (hp)	Annual Operating Limits (non-Emergency)	Proposed BACT
Caterpillar	3512	2003				1454	200	Current Owner Requested Limit of 600 hours/12-month period cumulative for these three engines.
Caterpillar	3512	2003				1454	200	
Caterpillar	3512	2003				1454	200	
Cummins	QSB7-G3 NR3	2012	Certified Engine			295	500	Comply with 40 CFR 60 Subpart IIII
John Deere	4024HF285B	2009	Certified Engine			67	500	Comply with 40 CFR 60 Subpart IIII
Caterpillar	CAT C9 GENSET	2007	Certified Engine			398	500	Comply with 40 CFR 60 Subpart IIII
SDMO	TM30UCM	ND				47	500	Good Combustion Practices
John Deere	JW64-UF30	2007	Certified Engine			275	500	Comply with 40 CFR 60 Subpart IIII
Clarke	DDFP-04AT	1994				235	500	Good Combustion Practices
Clarke	DDFP-04AT	1994				235	500	Good Combustion Practices
Clarke	DDFP-04AT	1994				235	500	Good Combustion Practices
Clarke	DDFP-04AT	1994				235	500	Good Combustion Practices
Cummins	N-855-F	1977				240	500	Good Combustion Practices
Cummins	N-855-F	1977				240	500	Good Combustion Practices
Clarke	JU4H-UF40	2005				94	500	Good Combustion Practices
Clarke	PDFP-06YT	1996				120	500	Good Combustion Practices
Clarke	PDFP-06YT	1996				120	500	Good Combustion Practices
Caterpillar 3516C	Backup Generator Engine	2009	Certified Engine	6.4	g/kw-hr	2,937	500	Comply with 40 CFR 60 Subpart IIII
Detroit 6V92	Generator Engine	1988		0.031	lb/hp-hr	353	500	Good Housekeeping Practices
Caterpillar C15	Generator Engine	2010	Certified Engine	6.4	g/kw-hr	762	500	Comply with 40 CFR 60 Subpart IIII
Caterpillar C15	Generator Engine	2010	Certified Engine	6.4	g/kw-hr	762	500	Comply with 40 CFR 60 Subpart IIII
Cummins B3.3	Generator Engine	2002		0.031	lb/hp-hr	82	500	Good Combustion Practices
Caterpillar 3406C TA	Generator Engine	2008	Certified Engine	4	g/kw-hr	587	500	Comply with 40 CFR 60 Subpart IIII
Cummins QSL-G2 NR3	Generator Engine	2008	Certified Engine	4	g/kw-hr	320	500	Comply with 40 CFR 60 Subpart IIII
Detroit R1237M36	Generator Engine	2005	Mfg Information	5.75	g/hp-hr	1,059	500	Good Housekeeping Practices
John Deere 6068TF250	Generator Engine	2005		0.031	lb/hp-hr	212	500	Good Combustion Practices
John Deere 6068TF250	Generator Engine	2007	Permit condition 23.1c	6.9	g/hp-hr	176	500	Good Combustion Practices
John Deere 6068HF150	Generator Engine	2005		0.031	lb/hp-hr	212	500	Good Combustion Practices
John Deere 4045TF270	Generator Engine	2007	Certified Engine	7.5	g/kw-hr	71	500	Comply with 40 CFR 60 Subpart IIII
John Deere 4239D	Generator Engine	1976		0.031	lb/hp-hr	35	500	Good Combustion Practices
Perkins 2046/1800	Generator Engine	2001		0.031	lb/hp-hr	95	500	Good Combustion Practices
Cummins	Generator Engine	1989		0.031	lb/hp-hr	35	500	Good Combustion Practices
John Deere 6068HF150	Generator Engine	2003		0.031	lb/hp-hr	155	500	Good Combustion Practices
Cummins L634D-I/10386E	Generator Engine	1993		0.031	lb/hp-hr	50	500	Good Combustion Practices
Caterpillar C1.5	Generator Engine	2011	Certified Engine	7.5	g/kw-hr	18	500	Comply with 40 CFR 60 Subpart IIII
Cummins 4B3.9-G2	Generator Engine	2003		0.031	lb/hp-hr	68	500	Good Combustion Practices
Caterpillar C6.6	Generator Engine	2010	Certified Engine	4	g/kw-hr	274	500	Comply with 40 CFR 60 Subpart IIII
Caterpillar C6.6	Generator Engine	2010	Certified Engine	4	g/kw-hr	274	500	Comply with 40 CFR 60 Subpart IIII
Detroit Diesel 10245100	Lift Pump Engine	1952		0.031	lb/hp-hr	75	500	Good Combustion Practices
Perkins	Lift Pump Engine	1955		0.031	lb/hp-hr	75	500	Good Combustion Practices
Perkins	Lift Pump Engine	1994		0.031	lb/hp-hr	75	500	Good Combustion Practices
Detroit Diesel 10447000	Well Pump Engine	1995		0.031	lb/hp-hr	220	500	Good Combustion Practices
John Deere 4045DF120	Well Pump Engine	2009	Certified Engine	7.8	g/hp-hr	55	500	Comply with 40 CFR 60 Subpart IIII
Detroit Diesel 4031-C	Well Pump Engine	1995		0.031	lb/hp-hr	220	500	Good Combustion Practices
John Deere 4045TF290	Lift Pump Engine	2014	Certified Engine	4.7	g/kW-hr	74	500	Comply with 40 CFR 60 Subpart IIII
John Deere 4045TF290	Lift Pump Engine	2014	Certified Engine	4.7	g/kW-hr	74	500	Comply with 40 CFR 60 Subpart IIII

BACT Cost Estimates for Particulate Matter Less Than 2.5 Microns ($PM_{2.5}$) Emissions from Engines
Doyon Utilities - Fort Wainwright (Privatized Emission Units)

Emission Unit ID	Emission Unit Name		Installation Date	Fuel Type	Factor Reference	$PM_{2.5}$ Emission Factor	Emission Unit Rating/Capacity	Allowable Annual Operation	Potential $PM_{2.5}$ Emissions	DPF Cost (CARB basis)	PM Reduced (tpy)	Cost/Ton Reduced	DPF Cost (ODEQ basis)	PM Reduced (tpy)	Cost/Ton Reduced	DOC Cost (ODEQ basis)	PM Reduced (tpy)	Cost/Ton Reduced
Significant Emission Units																		
8	Caterpillar 3516C	Backup Generator Engine	2009	Distillate	Certified Engine	0.20 g/kW-hr	2,937 hp	500 hr/yr	0.24 tpy	$ 111,606	0.20	$ 545,014	$ 5,750	0.22	$ 26,519	$ 1,500	0.07	$ 20,754
9	Detroit 6V92	Generator Engine	1988	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	353 hp	500 hr/yr	0.19 tpy	$ 13,410	0.16	$ 81,283	$ 5,750	0.17	$ 32,917	$ 1,500	0.06	$ 25,761
10	Caterpillar C15	Generator Engine	2010	Distillate	Certified Engine	0.2 g/kW-hr	762 hp	500 hr/yr	0.06 tpy	$ 28,956	0.05	$ 545,014	$ 5,750	0.06	$ 102,215	$ 1,500	0.02	$ 79,994
11	Caterpillar C15	Generator Engine	2010	Distillate	Certified Engine	0.2 g/kW-hr	762 hp	500 hr/yr	0.06 tpy	$ 28,956	0.05	$ 545,014	$ 5,750	0.06	$ 102,215	$ 1,500	0.02	$ 79,994
12	Cummins B3.3	Generator Engine	2002	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	82 hp	500 hr/yr	0.05 tpy	$ 3,116	0.04	$ 81,283	$ 5,750	0.04	$ 141,661	$ 1,500	0.01	$ 110,865
13	Caterpillar 3406C TA	Generator Engine	2008	Distillate	Certified Engine	2.00E-01 g/kW-hr	587 hp	500 hr/yr	0.05 tpy	$ 22,306	0.04	$ 545,014	$ 5,750	0.04	$ 132,688	$ 1,500	0.01	$ 103,842
14	Cummins QSL-G2 NR3	Generator Engine	2008	Distillate	Certified Engine	2.00E-01 g/kW-hr	320 hp	500 hr/yr	0.03 tpy	$ 12,160	0.02	$ 545,014	$ 5,750	0.02	$ 243,399	$ 1,500	0.01	$ 190,486
15	Detroit R1237M36	Generator Engine	2005	Distillate	Mfg Information	0.09 g/hp-hr	1,059 hp	500 hr/yr	0.05 tpy	$ 40,230	0.04	$ 903,149	$ 5,750	0.05	$ 121,914	$ 1,500	0.02	$ 95,411
16	John Deere 6068TF250	Generator Engine	2005	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	212 hp	500 hr/yr	0.12 tpy	$ 8,046	0.10	$ 81,283	$ 5,750	0.10	$ 54,861	$ 1,500	0.03	$ 42,935
17	John Deere 6068TF250	Generator Engine	2007	Distillate	Certified Engine	3.00E-01 g/kW-hr	176 hp	500 hr/yr	0.02 tpy	$ 6,705	0.02	$ 363,343	$ 5,750	0.02	$ 294,281	$ 1,500	0.01	$ 230,307
18	John Deere 6068HF150	Generator Engine	2005	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	212 hp	500 hr/yr	0.12 tpy	$ 8,046	0.10	$ 81,283	$ 5,750	0.10	$ 54,861	$ 1,500	0.03	$ 42,935
19	John Deere 4045TF270	Generator Engine	2007	Distillate	Certified Engine	4.00E-01 g/kW-hr	71 hp	500 hr/yr	0.01 tpy	$ 2,682	0.01	$ 272,507	$ 5,750	0.01	$ 551,777	$ 1,500	0.00	$ 431,825
20	John Deere 4239D	Generator Engine	1976	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	35 hp	500 hr/yr	0.02 tpy	$ 1,341	0.02	$ 81,283	$ 5,750	0.02	$ 329,168	$ 1,500	0.01	$ 257,610
21	Perkins 2046/1800	Generator Engine	2001	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	95 hp	500 hr/yr	0.05 tpy	$ 3,610	0.04	$ 81,283	$ 5,750	0.05	$ 122,275	$ 1,500	0.02	$ 95,694
22	Cummins	Generator Engine	1989	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	35 hp	500 hr/yr	0.02 tpy	$ 1,341	0.02	$ 81,283	$ 5,750	0.02	$ 329,168	$ 1,500	0.01	$ 257,610
23	John Deere 6068HF150	Generator Engine	2003	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	155 hp	500 hr/yr	0.09 tpy	$ 5,900	0.07	$ 81,283	$ 5,750	0.08	$ 74,811	$ 1,500	0.03	$ 58,548
24	Cummins L634D-I/10386E	Generator Engine	1993	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	50 hp	500 hr/yr	0.03 tpy	$ 1,900	0.02	$ 81,283	$ 5,750	0.02	$ 232,323	$ 1,500	0.01	$ 181,818
25	Caterpillar C1.5	Generator Engine	2011	Distillate	Certified Engine	4.00E-01 g/kW-hr	18 hp	500 hr/yr	0.00 tpy	$ 697	0.00	$ 272,507	$ 5,750	0.00	$ 2,122,218	$ 1,500	0.00	$ 1,660,866
26	Cummins 4B3.9-G2	Generator Engine	2003	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	68 hp	500 hr/yr	0.04 tpy	$ 2,584	0.03	$ 81,283	$ 5,750	0.03	$ 170,826	$ 1,500	0.01	$ 133,690
27	Caterpillar C6.6	Generator Engine	2010	Distillate	Certified Engine	2.00E-01 g/kW-hr	274 hp	500 hr/yr	0.02 tpy	$ 10,412	0.02	$ 545,014	$ 5,750	0.02	$ 284,261	$ 1,500	0.01	$ 222,465
28	Caterpillar C6.6	Generator Engine	2010	Distillate	Certified Engine	2.00E-01 g/kW-hr	274 hp	500 hr/yr	0.02 tpy	$ 10,412	0.02	$ 545,014	$ 5,750	0.02	$ 284,261	$ 1,500	0.01	$ 222,465
29a	John Deere 4045TF290	Lift Pump Engine	2014	Distillate	Certified Engine	3.00E-02 g/kW-hr	74 hp	500 hr/yr	0.00 tpy	$ 2,812	0.00	$ 3,633,428	$ 5,750	0.00	$ 7,016,904	$ 1,500	0.00	$ 5,491,490
30	Detroit Diesel 10245100	Lift Pump Engine	1952	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	75 hp	500 hr/yr	0.04 tpy	$ 2,850	0.04	$ 81,283	$ 5,750	0.04	$ 154,882	$ 1,500	0.01	$ 121,212
31a	John Deere 4045TF290	Lift Pump Engine	2014	Distillate	Certified Engine	3.00E-02 g/kW-hr	74 hp	500 hr/yr	0.00 tpy	$ 2,812	0.00	$ 3,633,428	$ 5,750	0.00	$ 7,016,904	$ 1,500	0.00	$ 5,491,490
32	Perkins	Lift Pump Engine	1955	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	75 hp	500 hr/yr	0.04 tpy	$ 2,850	0.04	$ 81,283	$ 5,750	0.04	$ 154,882	$ 1,500	0.01	$ 121,212
33	Perkins	Lift Pump Engine	1994	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	75 hp	500 hr/yr	0.04 tpy	$ 2,850	0.04	$ 81,283	$ 5,750	0.04	$ 154,882	$ 1,500	0.01	$ 121,212
34	Detroit Diesel 10447000	Well Pump Engine	1995	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	220 hp	500 hr/yr	0.12 tpy	$ 8,360	0.10	$ 81,283	$ 5,750	0.11	$ 52,801	$ 1,500	0.04	$ 41,322
35	John Deere 4045DF120	Well Pump Engine	2009	Distillate	Certified Engine	4.00E-01 g/kW-hr	55 hp	500 hr/yr	0.01 tpy	$ 2,090	0.01	$ 272,507	$ 5,750	0.01	$ 708,069	$ 1,500	0.00	$ 554,141
36	Detroit Diesel 4031-C	Well Pump Engine	1995	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	220 hp	500 hr/yr	0.12 tpy	$ 8,360	0.10	$ 81,283	$ 5,750	0.11	$ 52,801	$ 1,500	0.04	$ 41,322
									1.66 tpy		**0.25**	**tpy**		**0.17**	**tpy**		**1.16**	**tpy**
											max	$ 3,633,428			$ 7,016,904			$ 5,491,490
											min	$ 81,283			$ 26,519			$ 20,754
											ave	$ 496,042			$ 728,302			$ 569,975

Notes:
[a] $PM_{2.5}$ potential to emit calculations conservatively assumes that $PM_{2.5}$ emissions are equal to PM_{10} emissions.
For certified engines, PM2.5 is conservatively estimated as the PM Emission Standard applicable to that engine.
Conversion factors:

1 hp		0.7457	kW	
Weight		453.6	g/lb	
Weight		2,000	lb/ton	
Coal Heating Value		15.1	MMBtu/ton	*From www.usibelli.com/Coal_data.php*
CARB DPF Costs	$	38	$/hp	
CARB DPF Control		85%	PM2.5	
ODEQ Costs for DPF	$	5,750	$4000-$7500	ODEQ Clean Diesel Range, use average
ODEQ DPF Control		90%		
ODEQ DOC cost	$	1,500	$1000-$2000	ODEQ Clean Diesel Range, use average
ODEQ DOC Control		30%		

Source: DU Title V Renewal Permit Application, May 2013

Particulate Matter Less Than 2.5 Microns ($PM_{2.5}$) Emissions - Base Case for BACT analysis
Doyon Utilities - Fort Wainwright (Privatized Emission Units)

Emission Unit ID	Emission Unit Name	Fuel Type	Factor Reference	$PM_{2.5}$ Emission Factor [a]	Emission Unit Rating/Capacity	Allowable Annual Operation	Potential $PM_{2.5}$ Emissions
Significant Emission Units							
1	Coal-Fired Boiler 3	Coal	AP-42, Tables 1.1-5 and 1.1-6	0.782 lb/ton	230 mmbtu/hr	336,000 ton/year	131.4 tpy
2	Coal-Fired Boiler 4	Coal					
3	Coal-Fired Boiler 5	Coal					
4	Coal-Fired Boiler 6	Coal					
5	Coal-Fired Boiler 7	Coal					
6	Coal-Fired Boiler 8	Coal					
7a	South Coal Handling Dust Collector (DC-01)	N/A	See detailed calculations in Table D-1.7a in the Title V Renewal Permit Application		13,150 acfm	2,195 hr/yr	0.30 tpy
7b	South Underbunker Dust Collector (DC-02)	N/A			884 acfm	100 hr/yr	7.3E-03 tpy
7c	North Coal Handling Dust Collector (NDC-1)	N/A			9,250 acfm	45 hr/yr	3.4E-02 tpy
8	Backup Generator Engine	Distillate	Vendor	0.026 g/hp-hr	2,937 hp	500 hr/yr	4.2E-02 tpy
9	Generator Engine	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	353 hp	500 hr/yr	1.9E-01 tpy
10	Generator Engine	Distillate	AP-42, Table 3.4-1	0.0007 lb/hp-hr	762 hp	500 hr/yr	1.3E-01 tpy
11	Generator Engine	Distillate	AP-42, Table 3.4-1	0.0007 lb/hp-hr	762 hp	500 hr/yr	1.3E-01 tpy
12	Generator Engine	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	82 hp	500 hr/yr	4.5E-02 tpy
13	Generator Engine	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	587 hp	500 hr/yr	3.2E-01 tpy
14	Generator Engine	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	320 hp	500 hr/yr	1.8E-01 tpy
15	Generator Engine	Distillate	AP-42, Table 3.4-1	0.0007 lb/hp-hr	1,059 hp	500 hr/yr	1.9E-01 tpy
16	Generator Engine	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	212 hp	500 hr/yr	1.2E-01 tpy
17	Generator Engine	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	176 hp	500 hr/yr	9.7E-02 tpy
18	Generator Engine	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	212 hp	500 hr/yr	1.2E-01 tpy
19	Generator Engine	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	71 hp	500 hr/yr	3.9E-02 tpy
20	Generator Engine	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	35 hp	500 hr/yr	1.9E-02 tpy
21	Generator Engine	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	95 hp	500 hr/yr	5.2E-02 tpy
22	Generator Engine	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	35 hp	500 hr/yr	1.9E-02 tpy
23	Generator Engine	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	155 hp	500 hr/yr	8.5E-02 tpy
24	Generator Engine	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	50 hp	500 hr/yr	2.8E-02 tpy
25	Generator Engine	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	18 hp	500 hr/yr	1.0E-02 tpy
26	Generator Engine	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	68 hp	500 hr/yr	3.7E-02 tpy
27	Generator Engine	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	274 hp	500 hr/yr	1.5E-01 tpy
28	Generator Engine	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	274 hp	500 hr/yr	1.5E-01 tpy
29a	Lift Pump Engine	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	74 hp	500 hr/yr	4.1E-02 tpy
30	Lift Pump Engine	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	75 hp	500 hr/yr	4.1E-02 tpy
31a	Lift Pump Engine	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	74 hp	500 hr/yr	4.1E-02 tpy
32	Lift Pump Engine	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	75 hp	500 hr/yr	4.1E-02 tpy
33	Lift Pump Engine	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	75 hp	500 hr/yr	4.1E-02 tpy
34	Well Pump Engine	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	220 hp	500 hr/yr	1.2E-01 tpy
35	Well Pump Engine	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	55 hp	500 hr/yr	3.0E-02 tpy
36	Well Pump Engine	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	220 hp	500 hr/yr	1.2E-01 tpy
51a	Fly Ash Dust Collector (DC-1)	N/A	See detailed calculations in Table D-1.7b of Title V Renewal Permit Application		3,620 acfm	4,380 hr/yr	1.18 tpy
51b	Bottom Ash Dust Collector (DC-2)	N/A			3,620 acfm	4,380 hr/yr	1.18 tpy
52	Coal Storage Pile	N/A	See detailed calculations in Table D-1.7c of Title V Renewal P		N/A	82,049 tpy	3.22 tpy
Significant Emission Units Total Assessable Potential to Emit - $PM_{2.5}$							**139.9 tpy**
Insignificant Emission Units							
N/A	Fly and Bottom Ash Bin Vent Filter	N/A	See detailed calculations in Table D-1.7b of Title V Renewal Permit Application		1,460 acfm	4,380 hr/yr	0.47 tpy
N/A	Ash Loadout to Truck	N/A			N/A	28,560 tpy	0.0005 tpy
N/A	Aboveground Storage Tanks	Diesel	N/A	N/A	N/A	N/A	0 tpy
N/A	Underground Storage Tanks	Diesel	N/A	N/A	N/A	N/A	0 tpy
Insignificant Emission Units Total Assessable Potential to Emit - $PM_{2.5}$							**0.47 tpy**
Total Assessable Potential to Emit - $PM_{2.5}$							**140.4 tpy**[2]

Notes:
[a] $PM_{2.5}$ potential to emit calculations for all emission units (other than 1 through 6, 7a through 7c, 51a and 51b) conservatively assume that $PM_{2.5}$ emissions are equal to PM_{10} emissions.

Conversion factors:

Weight	453.6	g/lb
Weight	2,000	lb/ton

Original Source: Table D-1.8 from Title V Renewal Permit Application, May 2013; this table reflects greater emissions of PM2.5 than was included in the Title V Renewal Permit Application as a result of using 500 hours/year for emergency engines rather than 100 hours/year.

Revised Particulate Matter Less Than 2.5 Microns ($PM_{2.5}$) Emissions - Proposed
Doyon Utilities - Fort Wainwright (Privatized Emission Units)

Emission Unit ID	Emission Unit Name		Installation Date	Fuel Type	Factor Reference	$PM_{2.5}$ Emission Factor	Emission Unit Rating/Capacity	Allowable Annual Operation	Potential $PM_{2.5}$ Emissions
Significant Emission Units									
1	Coal-Fired Boiler 3		1953	Coal	MACT 2016 testing and MACTEC guidance on CPM emissions (to Mid Atlantic Regional Air Management Association) August 2008; See Excel Sheet "CPM and PM25 for CHPP Boilers"	0.46 lb/ton	230 mmbtu/hr	300,000 ton/year	69.0 tpy
2	Coal-Fired Boiler 4		1953	Coal		0.46 lb/ton	230 mmbtu/hr		
3	Coal-Fired Boiler 5		1953	Coal		0.46 lb/ton	230 mmbtu/hr		
4	Coal-Fired Boiler 6		1953	Coal		0.46 lb/ton	230 mmbtu/hr		
5	Coal-Fired Boiler 7		1953	Coal		0.46 lb/ton	230 mmbtu/hr		
6	Coal-Fired Boiler 8		1953	Coal		0.46 lb/ton	230 mmbtu/hr		
7a	South Coal Handling Dust Collector (DC-01)		2001	N/A			13,150 acfm	2,195 hr/yr	0.04 tpy
7b	South Underbunker Dust Collector (DC-02)		2005	N/A			884 acfm	100 hr/yr	0.00 tpy
7c	North Coal Handling Dust Collector (NDC-1)		2004	N/A	See detailed calculations in Table Coal Prep 7a 7b 7c		9,250 acfm	45 hr/yr	0.01 tpy
8	Caterpillar 3516C	Backup Generator Engine	2009	Distillate	Certified Engine	0.20 g/kW-hr	2,937 hp	500 hr/yr	0.24 tpy
9	Detroit 6V92	Generator Engine	1988	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	353 hp	500 hr/yr	0.19 tpy
10	Caterpillar C15	Generator Engine	2010	Distillate	Certified Engine	0.2 g/kW-hr	762 hp	500 hr/yr	0.06 tpy
11	Caterpillar C15	Generator Engine	2010	Distillate	Certified Engine	0.2 g/kW-hr	762 hp	500 hr/yr	0.06 tpy
12	Cummins B3.3	Generator Engine	2002	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	82 hp	500 hr/yr	0.05 tpy
13	Caterpillar 3406C TA	Generator Engine	2008	Distillate	Certified Engine	2.00E-01 g/kW-hr	587 hp	500 hr/yr	0.05 tpy
14	Cummins QSL-G2 NR3	Generator Engine	2008	Distillate	Certified Engine	2.00E-01 g/kW-hr	320 hp	500 hr/yr	0.03 tpy
15	Detroit R1237M36	Generator Engine	2005	Distillate	Mfg Information	0.09 g/hp-hr	1,059 hp	500 hr/yr	0.05 tpy
16	John Deere 6068TF250	Generator Engine	2005	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	212 hp	500 hr/yr	0.12 tpy
17	John Deere 6068TF250	Generator Engine	2007	Distillate	Certified Engine	3.00E-01 g/kW-hr	176 hp	500 hr/yr	0.02 tpy
18	John Deere 6068HF150	Generator Engine	2005	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	212 hp	500 hr/yr	0.12 tpy
19	John Deere 4045TF270	Generator Engine	2007	Distillate	Certified Engine	4.00E-01 g/kW-hr	71 hp	500 hr/yr	0.01 tpy
20	John Deere 4239D	Generator Engine	1976	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	35 hp	500 hr/yr	0.02 tpy
21	Perkins 2046/1800	Generator Engine	2001	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	95 hp	500 hr/yr	0.05 tpy
22	Cummins	Generator Engine	1989	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	35 hp	500 hr/yr	0.02 tpy
23	John Deere 6068HF150	Generator Engine	2003	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	155 hp	500 hr/yr	0.09 tpy
24	Cummins L634D-I/10386E	Generator Engine	1993	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	50 hp	500 hr/yr	0.03 tpy
25	Caterpillar C1.5	Generator Engine	2011	Distillate	Certified Engine	4.00E-01 g/kW-hr	18 hp	500 hr/yr	0.00 tpy
26	Cummins 4B3.9-G2	Generator Engine	2003	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	68 hp	500 hr/yr	0.04 tpy
27	Caterpillar C6.6	Generator Engine	2010	Distillate	Certified Engine	2.00E-01 g/kW-hr	274 hp	500 hr/yr	0.02 tpy
28	Caterpillar C6.6	Generator Engine	2010	Distillate	Certified Engine	2.00E-01 g/kW-hr	274 hp	500 hr/yr	0.02 tpy
29a	John Deere 4045TF290	Lift Pump Engine	2014	Distillate	Certified Engine	3.00E-02 g/kW-hr	74 hp	500 hr/yr	0.00 tpy
30	Detroit Diesel 10245100	Lift Pump Engine	1952	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	75 hp	500 hr/yr	0.04 tpy
31a	John Deere 4045TF290	Lift Pump Engine	2014	Distillate	Certified Engine	3.00E-02 g/kW-hr	74 hp	500 hr/yr	0.00 tpy
32	Perkins	Lift Pump Engine	1955	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	75 hp	500 hr/yr	0.04 tpy
33	Perkins	Lift Pump Engine	1994	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	75 hp	500 hr/yr	0.04 tpy
34	Detroit Diesel 10447000	Well Pump Engine	1995	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	220 hp	500 hr/yr	0.12 tpy
35	John Deere 4045DF120	Well Pump Engine	2009	Distillate	Certified Engine	4.00E-01 g/kW-hr	55 hp	500 hr/yr	0.01 tpy
36	Detroit Diesel 4031-C	Well Pump Engine	1995	Distillate	AP-42, Table 3.3-1	2.20E-03 lb/hp-hr	220 hp	500 hr/yr	0.12 tpy
51a	Fly Ash Dust Collector (DC-1)		1993	N/A	See detailed calculations in Table DU Ash Handling		3,620 acfm	4,380 hr/yr	0.18 tpy
51b	Bottom Ash Dust Collector (DC-2)		1994	N/A	See detailed calculations in Table DU Ash Handling		3,620 acfm	4,380 hr/yr	0.18 tpy
52	Coal Storage Pile		UNK	N/A	See detailed calculations in Table DU Coal Pile		N/A	82,049 tpy	3.22 tpy
								Significant Emission Units Total Potential to Emit - $PM_{2.5}$	**74.3 tpy**
Insignificant Emission Units									
N/A	Fly and Bottom Ash Bin Vent Filter			N/A	See detailed calculations in Table DU Ash Handling		1,460 acfm	4,380 hr/yr	0.07 tpy
N/A	Ash Loadout to Truck			N/A	See detailed calculations in Table DU Ash Handling		N/A	28,560 tpy	0.001 tpy
N/A	Aboveground Storage Tanks			Diesel	N/A	N/A	N/A	N/A	0 tpy
N/A	Underground Storage Tanks			Diesel	N/A	N/A	N/A	N/A	0 tpy
								Insignificant Emission Units Total Potential to Emit - $PM_{2.5}$	**0.07 tpy**
								Total Unlimited Potential to Emit - $PM_{2.5}$	**74.4** tpy[2]

Notes:
[a] $PM_{2.5}$ potential to emit calculations for all emission units other than 1 through 6, 7a through 7c, 51a, 51b, and 52 conservatively assume that $PM_{2.5}$ emissions are equal to PM_{10} emissions.
For certified engines, PM2.5 is conservatively estimated as the PM Emission Standard applicable to that engine.
Conversion factors:

1 hp	0.7457	kW	
Weight	453.6	g/lb	
Weight	2,000	lb/ton	
Coal Heating Value	15.1	MMBtu/ton	*From www.usibelli.com/Coal_data.php*

Source: Underlying data from Title V Renewal Permit Application. Modifications to the calculations for the boilers is detailed in the BACT Submittal.

Coal Handling Systems PM2.5 - Base Case for BACT Analysis
Doyon Utilities - Fort Wainwright (Privatized Emission Units)

Emission Unit			Factor Reference	PM_{10} Emission Factor	Emission Unit Rating/Capacity	Annual Operation[a]	Potential PM_{10} Emission[b]	Potential PM2.5 Emission[e]
Permit ID	Description	Year Installed						
7a	South Coal Handling Dust Collector (DC-01)	2001	Source Test, 2003	0.0025 gr/dscf	13,150 acfm	2,195 hr/yr	0.30 tpy	0.04 tpy
7b	South Underbunker Dust Collector (DC-02)	2005	Manufacturer's guarantee[c]	0.0200 gr/dscf	884 acfm	100 hr/yr	0.01 tpy	0.00 tpy
7c	North Coal Handling Dust Collector (NDC-1)	2004	Typical Value	0.0200 gr/dscf	9,250 acfm	45 hr/yr	0.03 tpy	0.01 tpy
						Total Emissions	**0.34 tpy**	**0.05 tpy**

Notes:

[a] Annual operating hours:

Maximum allowable coal consumption	336,000	tpy
Conveyor operation rate	150	tph
Annual operating hours for coal handling	2,240	hrs/yr
Average daily coal handling operations	6.14	hr/day, 365 operating days per year
Percent of time South coal handling dust collector is in use	98	percent, primary coal handling system
Percent of time North coal handling dust collector is in use	2	percent, North handling system is emergency backup to South handling system
Underbunker dust collector operating hours	100	hrs/yr, used only when emptying coal bunker for unscheduled boiler shutdown or bunker fire

[b] Coal handling dust collection emission calculations:

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

Temperature at standard conditions =	68	degrees Fahrenheit	293.15	degrees Kelvin
Exhaust temperature dust collectors =	85	degrees Fahrenheit	302.59	degrees Kelvin

[c] Manufacturer's guarantee for particle sizes 2 microns in diameter and larger; PM2.5 estimate is conservative as the 15% ratio identified in note e uses PM10 as the basis.

[e] Using the "Proposed Revisions to Fine Fraction Ratios Used for AP-42 Fugitive Dust Emission Factors" report authored by Chatten Cowherd, Jr., John Donaldson, and Robert Hegarty Midwest Research Institute, 425 Volker Blvd., Kansas City, MO 64110 ccowherd@mriresearch.org, in 2006, PM2.5 is calculated from these sources as 0.15*PM10.

Original Source: Table D 1.7a of Title V Renewal Permit Application, May 2013

Ash Handling System PM2.5 - Base Case for BACT Analaysis
Doyon Utilities - Fort Wainwright (Privatized Emission Units)

Emission Unit								
Permit ID	Description	Year Installed	Factor Reference	PM_{10} Emission Factor[d]	Emission Unit Rating/Capacity	Annual Operation	Potential PM_{10} Emission[b]	Potential PM2.5 Emission[e]
Significant Sources								
51a	Fly Ash Dust Collector (DC-1)	1993	Typical Value	0.02 gr/dscf	3,620 acfm	4,380 hr/yr [f]	1.18 tpy[a]	0.18 tpy
51b	Bottom Ash Dust Collector (DC-2)	1994	Typical Value	0.02 gr/dscf	3,620 acfm	4,380 hr/yr [f]	1.18 tpy[a]	0.18 tpy
Insignficant Sources								
N/A	Fly and Bottom Ash Bin Vent Filter	1993	Manufacturer's guarantee[c]	0.02 gr/scfm	1,460 acfm	4,380 hr/yr [g]	0.47 tpy[a]	0.07 tpy
N/A	Ash Loadout to Truck	Unknown	AP-42 11-19.2-2, truck loading conveyor crushed stone, 200% safety factor for "E" rating	3E-04 lb/ton		28,560 tpy	4.28E-03 tpy[b]	6.43E-04 tpy
						Total Emissions	**2.83 tpy**	**0.42 tpy**

Notes:

[a] Fly and bottom ash dust collector emission calculations:

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

Temperature at standard conditions =	68 degrees Fahrenheit	293.15 degrees Kelvin
Exhaust temperature of ash bin vent filter =	150 degrees Fahrenheit	338.71 degrees Kelvin
Exhaust temperature of fan duct blower/bag filter =	150 degrees Fahrenheit	

[b] Ash loadout emission calculations:

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

k = 0.35 for PM_{10}

U = mean wind speed = 5.4 mph in Fairbanks, per National Climactic Data Center (http://lwf.ncdc.noaa.gov/oa/climate/online/ccd/avgwind.html)

M = ash moisture content = 27 percent (AP-42, Table 13.2.4-1)

Ash loadout emissions based on maximum possible coal consumption

Boiler Rating	230 MMBtu/hr	
Coal Heating Value	15.1 MMBtu/ton	*From www.usibelli.com/Coal_data.php*
Number of boilers	6	
Maximum possible coal consumption per permit	336,000 tpy	
Ash content of coal per Usibelli Coal Mine website	8.5 percent	
Operations, ash tons/yr = coal consumption x (0.085 ash content)	28,560 tpy	
Ash loadout emissions, tons/yr = (emission factor, lb/ton) x (ash loading, ton/yr) / (2,000 lb/ton)		

[c] Manufacturer's guarantee for particle sizes over 5 microns in diameter

[d] To estimate uncontrolled emission factor, an estimated of 95% efficiency for dust collection filters was used. Controlled emissions are expected to be significantly less than the potential emission listed.

[e] Using the "Proposed Revisions to Fine Fraction Ratios Used for AP-42 Fugitive Dust Emission Factors" report authored by Chatten Cowherd, Jr., John Donaldson, and Robert Hegarty Midwest Research Institute, 425 Volker Blvd., Kansas City, MO 64110 ccowherd@mriresearch.org, in 2006, PM2.5 is calculated from these sources as 0.15*PM10.

[f] Average run time for DC-1 and DC-2 is 12 hours/day per reasonable inquiry of plant operations

[g] Operation of ash bin vent filter assumed to be the same as the dust collectors

Original Source: Table D-1.7b Ash Handling, Title V Renewal Permit Application, May 2013

Potential to Emit Calculations - Emergency Coal Storage Pile PM2.5
Doyon Utilities - Fort Wainwright (Privatized Emission Units)

Emission Unit: Permit ID	Emission Unit: Description	Factor Reference	PM_{10} Emission Factor	Annual Operation[b]	Potential PM_{10} Emission	Potential PM2.5 Emission[e]
	Coal chute to coal pile	AP-42, Section 13.2.4	3.63E-04 lb/ton[a]	90,322 tpy	1.64E-02 tpy	2.46E-03 tpy
	Front end loader drop onto stockpile	AP-42, Section 13.2.4	3.63E-04 lb/ton[a]	90,322 tpy	1.64E-02 tpy	2.46E-03 tpy
	Front end loader movement - chute to coal pile	AP-42, Section 13.2.2	2.92 lb/VMT[c]	760 VMT	1.11 tpy	1.67E-01 tpy
	Front end loader movement - coal pile to South grizzly	AP-42, Section 13.2.2	2.92 lb/VMT[c]	1,242 VMT	1.82 tpy	2.72E-01 tpy
	Front end loader movement - coal pile to North grizzly	AP-42, Section 13.2.2	2.92 lb/VMT[c]	101 VMT	0.15 tpy	2.22E-02 tpy
	Stockpile wind erosion	AP-42, Section 13.2.5	26.74 g/m^2 yr[d]	3,370 m^2	0.10 tpy	1.49E-02 tpy
	Front end loader drop into grizzly	AP-42, Section 13.2.4	3.63E-04 lb/ton[a]	90,322 tpy	1.64E-02 tpy	2.46E-03 tpy
52	Coal Storage Pile			**Total Emissions**	**3.22 tpy**	**3.22 tpy**

Notes:

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

k	0.35 for PM_{10}	
U = mean wind speed	5.4 miles/hr	per http://lwf.ncdc.noaa.gov/oa/climate/online/ccd/avgwind.html
M = coal moisture content	4.8 percent	

[b]For unlimited potential assume entire coal pile is turned over in one year:

Coal pile volume	133,810 yd^3	per September 24, 2012 survey
Density of coal	50 lb/ft^3	
Coal pile weight	90,322 tons	
Coal moved to coal pile	90,322 tpy	
Coal moved from coal pile	90,322 tpy	

[c]Front end loader movement emission factor from AP-42, Section 13.2.2, Empirical Equation 1a, $E = k \times (s/12)^a \times (W/3)^b$ lb/VMT where:

k	1.5 for PM_{10}
s = surface material silt content (haul road)	8.4 percent, from AP-42, Table 13.2.2-1
W = mean vehicle weight	27 tons, estimate
Size of load bucket	5 yd^3
Density of coal	50 lb/ft^3
Coal moved per trip	3.375 tons (Density of coal x 27 ft3/yd3 x bucket size / 2000 lb/ton)
a (empirical constant)	0.9 from AP-42, Table 13.2.2-2
b (empirical constant)	0.45 from AP-42, Table 13.2.2-2
Approximate distance from coal chute to coal pile (round trip)	150 feet
Approximate distance from coal pile to South grizzly (round trip)	250 feet
Approximate distance from coal pile to North grizzly (round trip)	1,000 feet
Percent of annual coal transferred to South grizzly	98 percent, primary coal handling system
Percent of annual coal transferred to North grizzly	2 percent, North handling system is emergency backup to South handling system
VMT = vehicles miles traveled per year	VMT = annual stockpile throughput/coal moved per trip x distanced traveled per round trip in feet / 5280 ft/mi

[d]From AP-42, Section 13.2.5, Industrial Wind Erosion

Coal Pile at FWA CHPP (*source: Topographic Map for the Coal Pile South of the Main Power Plant on Fort Wainwright, September 24, 2012, RCH Surveys*)

Average Height =	40 ft	
Width at Base =	205 ft	The minimum width (south face) of the coal pile is used as a conservative approach
Height-to-Base Ratio =	0.195	< 0.2. FWA CHPP coal pile can therefore be considered a large relatively flat pile with little penetration into the surface wind layer and and a single friction velocity (using Equation (1)) can be used to for the entire surface of the coal pile. Friction velocity is a measure of wind shear stress on the erodible surface.
Surface Area of Active (north) Face =	3,370 m^2	Calculated from survey using Computer Aided Design (CAD) software

AP-42 Section 13.2.5, Equation (2)
Emission factor for wind-generated particulate emissions from mixtures of erodible and nonerodible surface material subject to disturbance, EF

$$EF\ (g/m^2\text{-yr}) = k \sum_{i=1}^{N} P_i$$

where
k = particle size multiplier (0.5 for particle size < 10 microns, per table on page 13.2.5-3)
N = number of disturbances per year
P_i = erosion potential corresponding to the fastest mile of wind for the ith period between disturbances, g/m^2

AP-42 Section 13.2.5, Equation (3)
Erosion potential function for a dry exposed surface, P

$$P = 58\,(u^* - u_t^*)^2 + 25\,(u^* - u_t^*)$$
$$P = 0 \text{ for } u^* \leq u_t^*$$

where
u^* = friction velocity (m/s)
u_t = threshold friction velocity (m/s)

AP-42 Section 13.2.5, Equation (1)
Friction velocity, u*

$$u^* = 0.4 \times u(z) / \ln(z/z_0) \qquad \text{when } z > z_0$$

where
u^* = friction velocity (cm/s)
u(z) = wind speed at height z above test surface (cm/s)
z = height above test surface (cm)
z_0 = roughness height, cm

Data:

u(z)		Use maximum wind gust speed recorded at Fairbanks International Airport for each of the previous 12 months (see table below)
z	10	meters
N	215	disturbances/year for active face, as determined from 2012 records
	18	average disturbances/month

				Uncrusted coal pile[2] (Table 13.2.5-2)				Scraper tracks on coal pile (Table 13.2.5-2)								
Month-Year	Maximum Wind Speed (u(10))[1]		Wind Direction	Roughness Height (z_0)	Threshold Friction Velocity (u_t)	Calculated Friction Velocity (u^*)	Erosion potential function, P	Roughness Height (z_0)	Threshold Friction Velocity (u_t)	Calculated Friction Velocity (u^*)			Erosion potential function, P	P x N	k	Emission Factor, EF
	mph	m/s	deg	cm	m/s	m/s		cm	m/s	m/s						g/m^2-yr
Mar-12	23	10.3	250	0.3	1.12	0.51	0	0.06	0.62	0.42			0	0		
Apr-12	32	14.3	320	0.3	1.12	0.71	0	0.06	0.62	0.59			0	0		
May-12	33	14.8	140	0.3	1.12	0.73	0	0.06	0.62	0.61			0	0		
Jun-12	39	17.4	110	0.3	1.12		0	0.06	0.62	0.72			2.98	53.5		
Jul-12	32	14.3	320	0.3	1.12	0.71	0	0.06	0.62	0.59			0	0		
Aug-12	33	14.8	260	0.3	1.12	0.73	0	0.06	0.62	0.61			0	0		
Sep-12	31	13.9	240	0.3	1.12	0.68	0	0.06	0.62	0.57			0	0		
Oct-12	28	12.5	060	0.3	1.12	0.62	0	0.06	0.62	0.52			0	0		
Nov-12	24	10.7	030	0.3	1.12	0.53	0	0.06	0.62	0.44			0	0		
Dec-12	26	11.6	270	0.3	1.12	0.57	0	0.06	0.62	0.48			0	0		
Jan-13	28	12.5	270	0.3	1.12	0.62	0	0.06	0.62	0.52			0	0		
Feb-13	19	8.5	280	0.3	1.12	0.42	0	0.06	0.62	0.35			0	0		
Annual Total							0						2.98	53.48	0.5	**26.74**

[1]http://www.nws.noaa.gov/climate/index.php?wfo=pafg. Tower height of 10 meters confirmed by Fairbanks Weather Forecast Office, National Weather Service on 27-March-2013
[2]The erosion potential factor for the uncrusted coal pile is zero for all months. Therefore, wind erosion of the uncrusted coal pile is not a significant source of PM emissions

[e] Using the "Proposed Revisions to Fine Fraction Ratios Used for AP-42 Fugitive Dust Emission Factors" report authored by Chatten Cowherd, Jr., John Donaldson, and Robert Hegarty Midwest Research Institute, 425 Volker Blvd., Kansas City, MO 64110 ccowherd@mriresearch.org, in 2006, PM2.5 is calculated from these sources as 0.15*PM10.

Original Source: Title V Renewal Permit Application Table D-1.7c, May 2013

Sulfur Dioxide (SO_2) Emissions - Propsed
Doyon Utilities - Fort Wainwright (Privatized Emission Units)

Emission Unit ID	Emission Unit Name		Fuel Type	Fuel Sulfur Content	Factor Reference	SO_2 Emission Factor	Emission Unit Rating/Capacity	Allowable Annual Operation	Potential SO_2 Emissions
Significant Emission Units									
1	Coal-Fired Boiler 3		Coal	0.20 wt. pct.[a]	AP-42 Table 1.1-3	7 lb/ton-coal	300,000 tons/year	8,760 hr/yr	175.0 tpy
2	Coal-Fired Boiler 4		Coal			lb/ton-coal		8,760 hr/yr	175.0 tpy
3	Coal-Fired Boiler 5		Coal			lb/ton-coal		8,760 hr/yr	175.0 tpy
4	Coal-Fired Boiler 6		Coal			lb/ton-coal		8,760 hr/yr	175.0 tpy
5	Coal-Fired Boiler 7		Coal			lb/ton-coal		8,760 hr/yr	175.0 tpy
6	Coal-Fired Boiler 8		Coal			lb/ton-coal		8,760 hr/yr	175.0 tpy
7a	South Coal Handling Dust Collector (DC-01)		N/A	N/A	N/A	N/A	13,150 acfm	2,195 hr/yr	0 tpy
7b	South Underbunker Dust Collector (DC-02)		N/A	N/A	N/A	N/A	884 acfm	100 hr/yr	0 tpy
7c	North Coal Handling Dust Collector (NDC-1)		N/A	N/A	N/A	N/A	9,250 acfm	45 hr/yr	0 tpy
8	Caterpillar 3516C	Backup Generator Engine	Distillate	0.0015 wt. pct.[b]	Mass balance	0.212 lb/1000 gal	2,937 hp	500 hr/yr	0.01 tpy
9	Detroit 6V92	Generator Engine	Distillate	0.0015 wt. pct.	Mass balance	0.2 lb/1000 gal	353 hp	500 hr/yr	9.5E-04 tpy
10	Caterpillar C15	Generator Engine	Distillate	0.0015 wt. pct.[b]	Mass balance	0.212 lb/1000 gal	762 hp	500 hr/yr	2.1E-03 tpy
11	Caterpillar C15	Generator Engine	Distillate	0.0015 wt. pct.[b]	Mass balance	0.212 lb/1000 gal	762 hp	500 hr/yr	2.1E-03 tpy
12	Cummins B3.3	Generator Engine	Distillate	0.0015 wt. pct.	Mass balance	0.2 lb/1000 gal	82 hp	500 hr/yr	2.2E-04 tpy
13	Caterpillar 3406C TA	Generator Engine	Distillate	0.0015 wt. pct.[b]	Mass balance	0.2 lb/1000 gal	587 hp	500 hr/yr	1.6E-03 tpy
14	Cummins QSL-G2 NR3	Generator Engine	Distillate	0.0015 wt. pct.[b]	Mass balance	0.212 lb/1000 gal	320 hp	500 hr/yr	8.6E-04 tpy
15	Detroit R1237M36	Generator Engine	Distillate	0.0015 wt. pct.	Mass balance	0.2 lb/1000 gal	1,059 hp	500 hr/yr	2.9E-03 tpy
16	John Deere 6068TF250	Generator Engine	Distillate	0.0015 wt. pct.	Mass balance	0.2 lb/1000 gal	212 hp	500 hr/yr	5.7E-04 tpy
17	John Deere 6068TF250	Generator Engine	Distillate	0.0015 wt. pct.[b]	Mass balance	0.212 lb/1000 gal	176 hp	500 hr/yr	4.8E-04 tpy
18	John Deere 6068HF150	Generator Engine	Distillate	0.0015 wt. pct.	Mass balance	0.2 lb/1000 gal	212 hp	500 hr/yr	5.7E-04 tpy
19	John Deere 4045TF270	Generator Engine	Distillate	0.0015 wt. pct.[b]	Mass balance	0.2 lb/1000 gal	71 hp	500 hr/yr	1.9E-04 tpy
20	John Deere 4239D	Generator Engine	Distillate	0.0015 wt. pct.	Mass balance	0.2 lb/1000 gal	35 hp	500 hr/yr	9.5E-05 tpy
21	Perkins 2046/1800	Generator Engine	Distillate	0.0015 wt. pct.	Mass balance	0.2 lb/1000 gal	95 hp	500 hr/yr	2.6E-04 tpy
22	Cummins	Generator Engine	Distillate	0.0015 wt. pct.	Mass balance	0.2 lb/1000 gal	35 hp	500 hr/yr	9.5E-05 tpy
23	John Deere 6068HF150	Generator Engine	Distillate	0.0015 wt. pct.	Mass balance	0.2 lb/1000 gal	155 hp	500 hr/yr	4.2E-04 tpy
24	Cummins L634D-I/10386E	Generator Engine	Distillate	0.0015 wt. pct.	Mass balance	0.2 lb/1000 gal	50 hp	500 hr/yr	1.4E-04 tpy
25	Caterpillar C1.5	Generator Engine	Distillate	0.0015 wt. pct.[b]	Mass balance	0.212 lb/1000 gal	18 hp	500 hr/yr	5.0E-05 tpy
26	Cummins 4B3.9-G2	Generator Engine	Distillate	0.0015 wt. pct.	Mass balance	0.2 lb/1000 gal	68 hp	500 hr/yr	1.8E-04 tpy
27	Caterpillar C6.6	Generator Engine	Distillate	0.0015 wt. pct.[b]	Mass balance	0.212 lb/1000 gal	274 hp	500 hr/yr	7.4E-04 tpy
28	Caterpillar C6.6	Generator Engine	Distillate	0.0015 wt. pct.[b]	Mass balance	0.212 lb/1000 gal	274 hp	500 hr/yr	7.4E-04 tpy
29a	John Deere 4045TF290	Lift Pump Engine	Distillate	0.0015 wt. pct.[b]	Mass balance	0.2 lb/1000 gal	74 hp	500 hr/yr	2.0E-04 tpy
30	Detroit Diesel 10245100	Lift Pump Engine	Distillate	0.0015 wt. pct.	Mass balance	0.2 lb/1000 gal	75 hp	500 hr/yr	2.0E-04 tpy
31a	John Deere 4045TF290	Lift Pump Engine	Distillate	0.0015 wt. pct.	Mass balance	0.2 lb/1000 gal	74 hp	500 hr/yr	2.0E-04 tpy
32	Perkins	Lift Pump Engine	Distillate	0.0015 wt. pct.	Mass balance	0.2 lb/1000 gal	75 hp	500 hr/yr	2.0E-04 tpy
33	Perkins	Lift Pump Engine	Distillate	0.0015 wt. pct.	Mass balance	0.2 lb/1000 gal	75 hp	500 hr/yr	2.0E-04 tpy
34	Detroit Diesel 10447000	Well Pump Engine	Distillate	0.0015 wt. pct.	Mass balance	0.2 lb/1000 gal	220 hp	500 hr/yr	5.9E-04 tpy
35	John Deere 4045DF120	Well Pump Engine	Distillate	0.0015 wt. pct.[b]	Mass balance	0.2 lb/1000 gal	55 hp	500 hr/yr	1.5E-04 tpy
36	Detroit Diesel 4031-C	Well Pump Engine	Distillate	0.50 wt. pct.	Mass balance	70.5 lb/1000 gal	220 hp	500 hr/yr	2.0E-01 tpy
51a	Fly Ash Dust Collector (DC-1)		N/A	N/A	N/A	N/A	3,620 acfm	4,380 hr/yr	0.00 tpy
51b	Bottom Ash Dust Collector (DC-2)		N/A	N/A	N/A	N/A	3,620 acfm	4,380 hr/yr	0.00 tpy
52	Coal Storage Pile		N/A	N/A	N/A	N/A	N/A	82,049 tpy	0.00 tpy
Significant Emission Units Potential to Emit - SO_2									**1,050.2 tpy**
Insignificant Emission Units									
N/A	Fly and Bottom Ash Bin Vent Filter		N/A	N/A	N/A	N/A	1,460 acfm	8,760 hr/yr	0 tpy
N/A	Ash Loadout to Truck		N/A	N/A	N/A	N/A	N/A	67,960 tpy	0 tpy
N/A	Aboveground Storage Tanks		Diesel	N/A	N/A	N/A	N/A	N/A	0 tpy
N/A	Underground Storage Tanks		Diesel	N/A	N/A	N/A	N/A	N/A	0 tpy
Insignificant Emission Units Potential to Emit - SO_2									**0 tpy**
Total Potential to Emit - SO_2									**1,050.2 tpy**

Notes:
[a] Weighted Sulfur content, averaged over 2015-2016=0.13
[b] For engines subject to 40 CFR 60 Subpart IIII, fuel used must meet the requirements of 40 CFR 80.510(b).

Conversion factors:

Diesel Heating Value	137,000 Btu/gal	*From AP 42, Appendix A, Page A-5*
Density of Diesel	7.05 lb/gal	*From AP 42, Appendix A, Page A-7, density for Distillate Oil*
Engine Heat Rate	7,000 Btu/hp-hr	*Average brake-specific fuel consumption (BSFC) from AP 42, Table 3.3-1, footnote a*
Weight	2,000 lb/ton	
Coal Heating Value	15.1 MMBtu/ton	*From www.usibelli.com/Coal_data.php*

SO2 emissions from Coal combustion at CHPP

AP-42 emission factor, table 1.1-3 35*%S by weight

Usibelli Coal Data sheet indicates range between 0.08 and 0.28% gross as received. http://www.usibelli.com/coal/data-sheet, accessed

% S by weight 0.20 June 8, 2017
SO2 emission factor 7 lb/ton coal

From CHPP data
coal BTU content 7572 Btu/lb 2016 average

SO2 0.46 lb SO2/MMBTU

Sulfur Dioxide (SO_2) Emissions - Base Case
Doyon Utilities - Fort Wainwright (Privatized Emission Units)

Emission Unit ID	Emission Unit Name		Fuel Type	Fuel Sulfur Content	Factor Reference	SO_2 Emission Factor	Emission Unit Rating/Capacity	Allowable Annual Operation	Potential SO_2 Emissions
Significant Emission Units									
1	Coal-Fired Boiler 3		Coal	0.28 wt. pct.[a]	AP-42 Table 1.1-3	9.8 lb/ton-coal	336,000 tons/year	8,760 hr/yr	274.4 tpy
2	Coal-Fired Boiler 4		Coal			9.8 lb/ton-coal		8,760 hr/yr	274.4 tpy
3	Coal-Fired Boiler 5		Coal			9.8 lb/ton-coal		8,760 hr/yr	274.4 tpy
4	Coal-Fired Boiler 6		Coal			9.8 lb/ton-coal		8,760 hr/yr	274.4 tpy
5	Coal-Fired Boiler 7		Coal			9.8 lb/ton-coal		8,760 hr/yr	274.4 tpy
6	Coal-Fired Boiler 8		Coal			9.8 lb/ton-coal		8,760 hr/yr	274.4 tpy
7a	South Coal Handling Dust Collector (DC-01)		N/A	N/A	N/A	N/A	13,150 acfm	2,195 hr/yr	0 tpy
7b	South Underbunker Dust Collector (DC-02)		N/A	N/A	N/A	N/A	884 acfm	100 hr/yr	0 tpy
7c	North Coal Handling Dust Collector (NDC-1)		N/A	N/A	N/A	N/A	9,250 acfm	45 hr/yr	0 tpy
8	Caterpillar 3516C	Back up Generator Engine	Distillate	0.0015 wt. pct.[b]	Mass balance	0.212 lb/1000 gal	2,937 hp	500 hr/yr	7.93E-03 tpy
9	Detroit 6V92	Generator Engine	Distillate	0.50 wt. pct.	Mass balance	70.5 lb/1000 gal	353 hp	500 hr/yr	3.18E-01 tpy
10	Caterpillar C15	Generator Engine	Distillate	0.0015 wt. pct.[b]	Mass balance	0.212 lb/1000 gal	762 hp	500 hr/yr	2.06E-03 tpy
11	Caterpillar C15	Generator Engine	Distillate	0.0015 wt. pct.[b]	Mass balance	0.212 lb/1000 gal	762 hp	500 hr/yr	2.06E-03 tpy
12	Cummins B3.3	Generator Engine	Distillate	0.50 wt. pct.	Mass balance	70.5 lb/1000 gal	82 hp	500 hr/yr	7.38E-02 tpy
13	Caterpillar 3406C TA	Generator Engine	Distillate	0.0015 wt. pct.[b]	Mass balance	0.2 lb/1000 gal	587 hp	500 hr/yr	1.59E-03 tpy
14	Cummins QSL-G2 NR3	Generator Engine	Distillate	0.0015 wt. pct.[b]	Mass balance	0.212 lb/1000 gal	320 hp	500 hr/yr	8.65E-04 tpy
15	Detroit R1237M36	Generator Engine	Distillate	0.50 wt. pct.	Mass balance	70.5 lb/1000 gal	1,059 hp	500 hr/yr	9.53E-01 tpy
16	John Deere 6068TF250	Generator Engine	Distillate	0.50 wt. pct.	Mass balance	70.5 lb/1000 gal	212 hp	500 hr/yr	1.91E-01 tpy
17	John Deere 6068TF250	Generator Engine	Distillate	0.0015 wt. pct.[b]	Mass balance	0.212 lb/1000 gal	176 hp	500 hr/yr	4.77E-04 tpy
18	John Deere 6068HF150	Generator Engine	Distillate	0.50 wt. pct.	Mass balance	70.5 lb/1000 gal	212 hp	500 hr/yr	1.91E-01 tpy
19	John Deere 4045TF270	Generator Engine	Distillate	0.0015 wt. pct.[b]	Mass balance	0.2 lb/1000 gal	71 hp	500 hr/yr	1.91E-04 tpy
20	John Deere 4239D	Generator Engine	Distillate	0.50 wt. pct.	Mass balance	70.5 lb/1000 gal	35 hp	500 hr/yr	3.18E-02 tpy
21	Perkins 2046/1800	Generator Engine	Distillate	0.50 wt. pct.	Mass balance	70.5 lb/1000 gal	95 hp	500 hr/yr	8.56E-02 tpy
22	Cummins	Generator Engine	Distillate	0.50 wt. pct.	Mass balance	70.5 lb/1000 gal	35 hp	500 hr/yr	3.18E-02 tpy
23	John Deere 6068HF150	Generator Engine	Distillate	0.50 wt. pct.	Mass balance	70.5 lb/1000 gal	155 hp	500 hr/yr	1.40E-01 tpy
24	Cummins L634D-I/10386E	Generator Engine	Distillate	0.50 wt. pct.	Mass balance	70.5 lb/1000 gal	50 hp	500 hr/yr	4.50E-02 tpy
25	Caterpillar C1.5	Generator Engine	Distillate	0.0015 wt. pct.[b]	Mass balance	0.212 lb/1000 gal	18 hp	500 hr/yr	4.96E-05 tpy
26	Cummins 4B3.9-G2	Generator Engine	Distillate	0.50 wt. pct.	Mass balance	70.5 lb/1000 gal	68 hp	500 hr/yr	6.12E-02 tpy
27	Caterpillar C6.6	Generator Engine	Distillate	0.0015 wt. pct.[b]	Mass balance	0.212 lb/1000 gal	274 hp	500 hr/yr	7.40E-04 tpy
28	Caterpillar C6.6	Generator Engine	Distillate	0.0015 wt. pct.[b]	Mass balance	0.212 lb/1000 gal	274 hp	500 hr/yr	7.40E-04 tpy
29a	John Deere 4045TF290	Lift Pump Engine	Distillate	0.0015 wt. pct.[b]	Mass balance	0.2 lb/1000 gal	74 hp	500 hr/yr	2.00E-04 tpy
30	Detroit Diesel 10245100	Lift Pump Engine	Distillate	0.50 wt. pct.	Mass balance	70.5 lb/1000 gal	75 hp	500 hr/yr	6.75E-02 tpy
31a	John Deere 4045TF290	Lift Pump Engine	Distillate	0.50 wt. pct.	Mass balance	70.5 lb/1000 gal	74 hp	500 hr/yr	6.66E-02 tpy
32	Perkins	Lift Pump Engine	Distillate	0.50 wt. pct.	Mass balance	70.5 lb/1000 gal	75 hp	500 hr/yr	6.75E-02 tpy
33	Perkins	Lift Pump Engine	Distillate	0.50 wt. pct.	Mass balance	70.5 lb/1000 gal	75 hp	500 hr/yr	6.75E-02 tpy
34	Detroit Diesel 10447000	Well Pump Engine	Distillate	0.50 wt. pct.	Mass balance	70.5 lb/1000 gal	220 hp	500 hr/yr	1.98E-01 tpy
35	John Deere 4045DF120	Well Pump Engine	Distillate	0.0015 wt. pct.[b]	Mass balance	0.2 lb/1000 gal	55 hp	500 hr/yr	1.49E-04 tpy
36	Detroit Diesel 4031-C	Well Pump Engine	Distillate	0.50 wt. pct.	Mass balance	70.5 lb/1000 gal	220 hp	500 hr/yr	1.98E-01 tpy
51a	Fly Ash Dust Collector (DC-1)		N/A	N/A	N/A	N/A	3,620 acfm	4,380 hr/yr	0.00 tpy
51b	Bottom Ash Dust Collector (DC-2)		N/A	N/A	N/A	N/A	3,620 acfm	4,380 hr/yr	0.00 tpy
52	Coal Storage Pile		N/A	N/A	N/A	N/A	N/A	82,049 tpy	0.00 tpy
								Significant Emission Units Potential to Emit - SO_2	**1,649.2 tpy**
Insignificant Emission Units									
N/A	Fly and Bottom Ash Bin Vent Filter		N/A	N/A	N/A	N/A	1,460 acfm	4,380 hr/yr	0 tpy
N/A	Ash Loadout to Truck		N/A	N/A	N/A	N/A	N/A	28,560 tpy	0 tpy
N/A	Aboveground Storage Tanks		Diesel	N/A	N/A	N/A	N/A	N/A	0 tpy
N/A	Underground Storage Tanks		Diesel	N/A	N/A	N/A	N/A	N/A	0 tpy
								Insignificant Emission Units Potential to Emit - SO_2	**0 tpy**
								Total Potential to Emit - SO_2	**1,649.2 tpy**

Notes:
[a] Weighted Sulfur content, averaged over 2015-2016=0.13
[b] For engines subject to 40 CFR 60 Subpart IIII, fuel used must meet the requirements of 40 CFR 80.510(b).

Conversion factors:

Diesel Heating Value	137,000 Btu/gal	*From AP 42, Appendix A, Page A-5*
Density of Diesel	7.05 lb/gal	*From AP 42, Appendix A, Page A-7, density for Distillate Oil*
Engine Heat Rate	7,000 Btu/hp-hr	*Average brake-specific fuel consumption (BSFC) from AP 42, Table 3.3-1, footnote a*
Weight	2,000 lb/ton	
Coal Heating Value	15.1 MMBtu/ton	*From www.usibelli.com/Coal_data.php*

SO2 emissions from Coal combustion at CHPP

AP-42 emission factor, table 1.1-3 35*%S by weight

Usibelli Coal Data sheet indicates range between 0.08 and 0.28% gross as received. http://www.usibelli.com/coal/data-sheet, accessed June 8, 2017

% S by weight 0.28
SO2 emission factor 9.8 lb/ton coal

From CHPP data
coal BTU content 7572 Btu/lb 2016 average

SO2 0.65 lb SO2/MMBTU

Original Source: Title V Renewal Permit Application, Table D-1.10 SO2, May 2013

APPENDIX C

PHOTOS OF MATERIAL HANDLING EQUIPMENT

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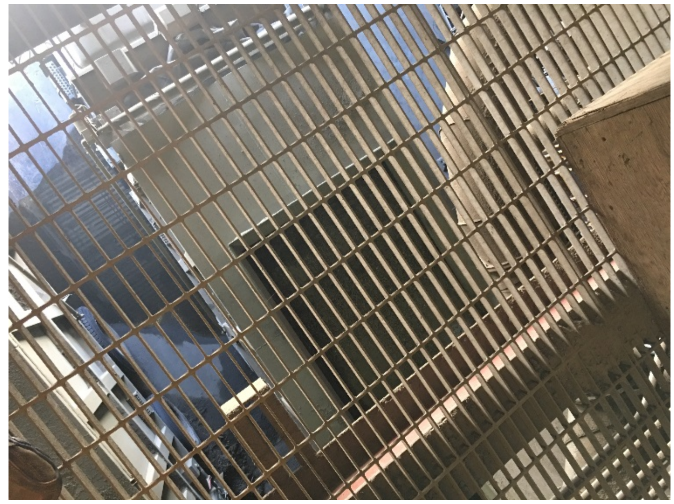
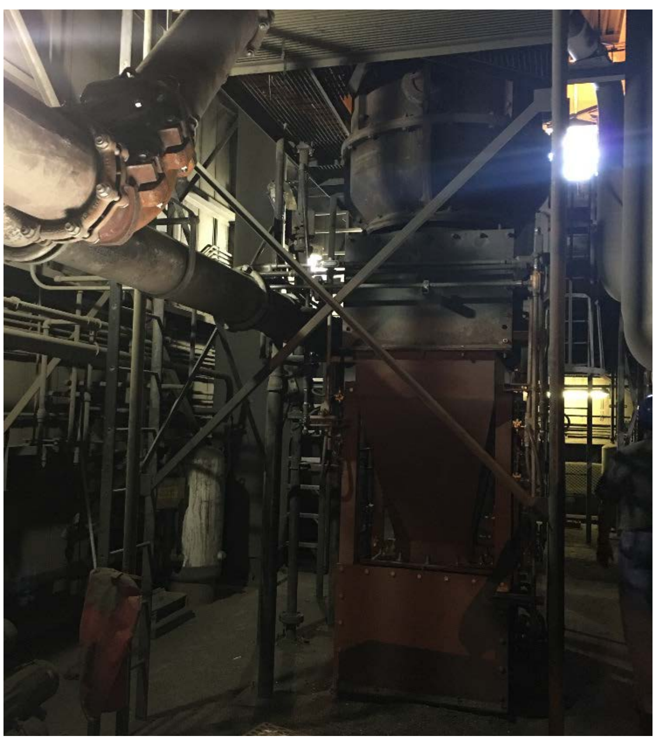
Bottom Ash transportation pipe



Bottom Ash transportation point



Bottom Ash Hopper

Bottom Ash collection point from boilers

Coal Dust Control Suction in Enclosed Coal Conveyor

Close up of Bottom Ash Collection Point

Coal Dust Collection Vacuum Suction on Level 6

Coal Conveyor System on Level 6 of the CHPP

Coal Stack

Coal Unloading Point from Bottom of Rail Car

Enclosed Bottom Ash Conveyor System

Enclosed Coal Conveyor from Coal Unloading to Coal Elevator

Fly Ash Transportation Point

Fly Ash Hopper

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APPENDIX D

PHOTOS OF OVER FIRE AIR SYSTEM

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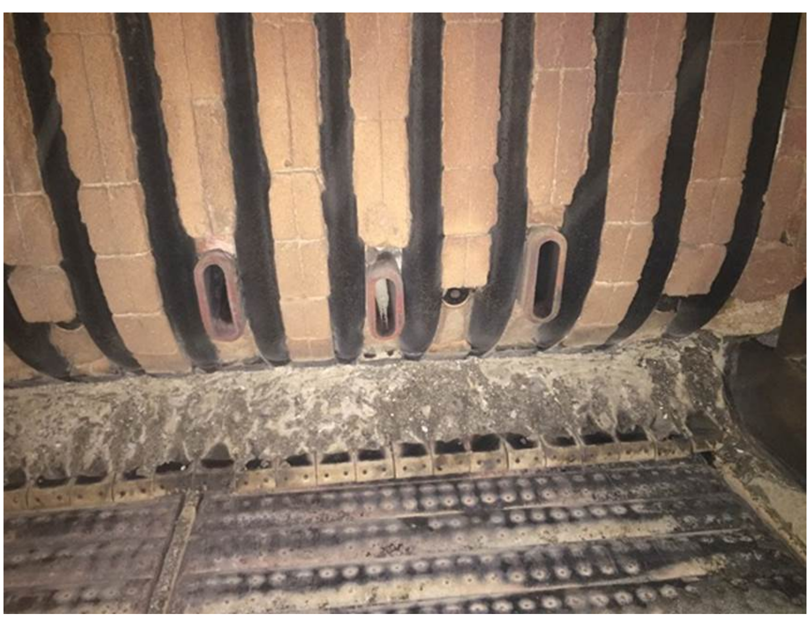
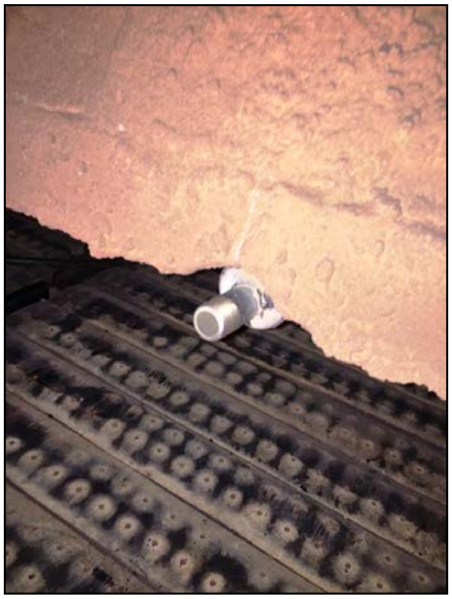
¾" pipe shown with no forged nozzles on the upper rear wall.

Lower rear wall of a nozzle with forged end similar to the front.



Cinder return nozzles



Air flow shown parallel to the grate. ¾" pipe nipples were welded to the forged nozzle head for Boilers 3 & 5.

Forged ¾" Apature Nozzle

Forged ¾" Apature Nozzle

Forged ¾" aperture nozzle welded into 2" pipe for front wall.

Forged nozzles shown with air flow parallel to the grate. No pipe nipples were used for Boilers 4, 6, 7, and 8.

APPENDIX E

DOYON UTILITIES, LLC, RACT LETTER

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DOYON UTILITIES LLC

714 Fourth Avenue, Suite 100 • Fairbanks, AK 99701
PO Box 74040 • Fairbanks, AK 99707
Phone (907) 455-1500 • Fax (907) 455-6788

October 19, 2016

Denise Koch, Director
Division of Air Quality
Alaska Department of Environmental Conservation
P.O. Box 11800
Juneau, Alaska 99811-1800

SUBJECT: Moderate $PM_{2.5}$ Nonattainment SIP – NO_X RACT Analysis

Dear Ms. Koch,

Doyon Utilities, LLC (DU) operates six coal-fired boilers at the Fort Wainwright (Privatized Emission Units) stationary source under Permit No. AQ1121TVP02, Revision 2. Fort Wainwright is a U. S. Army post located in Fairbanks, Alaska. DU is responding to the Alaska Department of Environmental Conservation (ADEC) request to provide site-specific cost data for the coal-fired boilers. DU understands that ADEC will use this information to update the nitrogen oxides (NO_X) Reasonably Available Control Technology (RACT) analysis in the moderate $PM_{2.5}$ Nonattainment State Implementation Plan (SIP).

Executive Summary

DU reviewed the existing NO_X RACT analysis in the moderate $PM_{2.5}$ Nonattainment SIP and identified additional available emission control options for the coal-fired boilers, Emission Units (EUs) 1 through 6, at Fort Wainwright. Consistent with the top-down Best Available Control Technology (BACT) process provided in the U.S. Environmental Protection Agency (EPA) 1990 Draft New Source Review (NSR) Workshop Manual, DU reviewed the technical feasibility and control effectiveness of the available NO_X emission control options and evaluated feasible emission control options. This effort included updating emission control technology cost data. Through this analysis, DU has identified combustion control as NO_X RACT for the coal-fired boilers at Fort Wainwright.

Background

EPA designated portions of the Fairbanks North Star Borough (FNSB), including the City of Fairbanks and the City of North Pole, as a moderate nonattainment area for fine particulate matter ($PM_{2.5}$, particulate matter with a diameter less than 2.5 micrometers in diameter) in 2009 [74 FR 58,688; 13 November 2009]. For $PM_{2.5}$ nonattainment evaluation purposes, both direct $PM_{2.5}$ and $PM_{2.5}$ precursors must be considered. $PM_{2.5}$ precursors include sulfur dioxide (SO_2), NO_X, volatile organic compounds (VOC), and ammonia (NH_3).

EUs 1 through 6 are coal-fired spread-stoker boilers each rated at 230 million British thermal units per hour (MMBtu/hr) of heat input. The boilers are fired with subbituminous coal from the Usibelli Coal Mine in Healy, Alaska. The boilers produce steam which heats the entire post via a steam distribution system. The steam is also used in steam turbine generators to produce electricity for the post. The boilers were installed in 1953 and are currently equipped with O_2 trim systems and full-stream fabric filter baghouses as emission control devices. Appendix III.D.5.7 of the December 24, 2014 moderate $PM_{2.5}$ Nonattainment SIP provides Individual Emission Unit RACT Determinations in Table 1, Emission Units (page Appendix III.D.5.7-64). This table incorrectly identifies current emission controls for the FWA coal-fired boilers. A baghouse and an O_2 trim system should be listed as current emission controls for each of the six coal-fired boilers listed in Table 1, Emission Units (page Appendix III.D.5.7-64).

Because each coal-fired boiler generates less than 25 megawatts electrical output, EUs 1 through 6, do not meet the definition of electric utility steam generating unit (EGU) provided in 40 CFR 60 Subpart A. In addition, electricity generated at the facility is not for sale or sold to any entity. The Defense Logistics Agency (DLA) pays DU to operate the privatized emission units at FWA, which are owned by DU. The utilities privatization contract specifies that DLA owns the electricity and steam generated at FWA.

Available NOx Emission Control Technologies
Table 1 identifies six available NOx emission control technologies for non-EGU coal-fired boilers rated at 230 MMBtu/hr. The available emission control technologies were identified by searching the EPA RACT/BACT/LAER Clearinghouse (RBLC) and the EPA Menu of Control Measures (MCM) for National Ambient Air Quality Standards (NAAQS) Implementations for non-EGU coal-fired stoker boilers.

Table 1. Summary of Available NOx Emission Control Technology Coal Fired Boilers >100 MMBtu/hr and < 250 MMBtu/hr (RBLC 12.110)

Pollutant	Emission Control Technology Used	Number of RBLC Entries (3 Total)[1]
NOx	SNCR + Combustion Control	1
	SCR + Combustion Control	0
	SNCR	0
	SCR	0
	Combustion Control	0
	None	2

[1] Data are based on a RBLC review from January 1, 2005 through October 10, 2016.

Technical Feasibility
A discussion is provided below for each available NOx emission control technology identified for EU IDs 1 through 6.

- **SNCR**

Selective non-catalytic reduction (SNCR) is a post-combustion emission control technology that involves a non-catalytic chemical reaction through the use of a reagent, such as urea or ammonia, to reduce NOx into nitrogen and water. Reagent use has the potential to produce ammonia slip. Ammonia is a $PM_{2.5}$ precursor. Per Section 4, Chapter 1 of the EPA Air Pollution Cost Control Manual (May 2016), SNCR is only effective in a narrow temperature range of 1,550°F to 1,950°F. SNCR is not suitable if temperatures are too low because the NO_X reduction reaction is favored only within the temperature window. At temperatures outside the temperature window, other chemical reactions occur instead. Table 2 provides stack outlet temperatures for EU IDs 1 through 6 as recorded during Boiler MACT source testing conducted June 15 through 20, 2016. The final test report was submitted to ADEC on August 18, 2016.

Table 2. Boiler MACT Source Test Stack Temperatures

EU ID	Description	Rating	Stack Temperature[1] (°F)
1	Boiler No. 3	230 MMBtu/hr	300
2	Boiler No. 4	230 MMBtu/hr	337
3	Boiler No. 5	230 MMBtu/hr	312
4	Boiler No. 6	230 MMBtu/hr	352
5	Boiler No. 7	230 MMBtu/hr	305
6	Boiler No. 8	230 MMBtu/hr	342

[1] Determined from 3-run average during Boiler MACT source test for CO, PM, and HCl conducted June 15 through 20, 2016.

As shown in Table 2, the outlet stack temperatures for EU IDs 1 through 6 are, in general, between 300°F and 350°F, which is well below the recommended SNCR temperature range of 1,550°F to 1,950°F. A considerable amount of heat would be required to achieve the specified temperature range, especially given the number of days on which subzero temperatures occur at FWA. Generating energy for heating would require additional fuel combustion and would result in additional emissions of direct $PM_{2.5}$ and $PM_{2.5}$ precursors. As noted above, ammonia slip is anticipated with SNCR use, resulting in additional $PM_{2.5}$ precursor emissions. Ammonia is more toxic than NO_X and is classified by EPA as a hazardous material.

Page 1-7 of the EPA Air Pollution Cost Control Manual [Section 4, Chapter 1, May 2016] states, "SNCR is not suitable for sources where the residence time is too short, temperatures are too low, NO_X concentrations are low, the reagent would contaminate the product, or no suitable location exists for installing reagent injection ports." DU agrees with EPA and has determined that SNCR is not a technically feasible control measure due to the temperature differential of the stack gas as compared to the recommended NSCR operating temperature range.

- **SCR**

Selective catalytic reduction (SCR) is a post-combustion emission control technology that reduces NO_X into nitrogen, water, and O_2 by injecting a reducing agent, ammonia or urea, into the flue gas upstream of a metal-based catalyst. Reagent use has the potential to produce ammonia slip. As noted above, ammonia is a $PM_{2.5}$ precursor. Ammonia is more toxic than NO_X and is classified by EPA as a hazardous material. SCR offers a higher NO_X reduction efficiency than NSCR and is capable of accommodating lower flue gas temperatures. Per Section 4, Chapter 2 of the EPA Air Pollution Cost Control Manual (May 2016), SCR is effective in a temperature range of 480°F to 800°F. Reheating the flue gas increases operational costs significantly. Additional heat would be required to achieve the desired flue gas temperature range, especially given the number of days on which subzero temperatures are encountered at FWA. Additional power would be needed to pump and heat aqueous ammonia solution. Generating the additional energy for heating and electrical consumption needs would increase coal combustion and would result in an increase in emission, including additional emissions of direct $PM_{2.5}$ and $PM_{2.5}$ precursors. An additional structure would be required to house the flue gas re-heating system, the catalyst bed, and other SCR system components. Additional building space may be available west of the existing FWA baghouse structure. In addition to the direct cost of purchasing, installing, and operating SCR system equipment, placing a new structure west of the baghouse would likely involve expenses for relocation of the existing paved road, relocation of buried utilities, and redesigning the storm drainage system.

SCR is a technically feasible NO_X emission control measure. Because combustion control is already installed, both emission control technologies will be reviewed together as SCR + Combustion Control for the remainder of the analysis.

- **Combustion Control**

Combustion control involves the practice of combustion optimization through the reduction of thermal NO_X formation. Limiting peak flame temperature in the combustion zone by restricting O_2 availability can reduce thermal NO_X formation. EUs 1 through 6 at FWA are equipped with O_2 trim systems, which maintain optimum air-to-fuel ratios.

The O_2 concentration of the flue gas is determined by O_2 analyzers, which are installed downstream of induced draft fans. These devices are located approximately 30 feet below each stack top to obtain a representative sample of the flue gas. The O_2 analyzers provide an output signal to the distributed control system (DCS), a central computer that manages facility instrumentation processes. The DCS submits a feedback signal to the boiler controller based on programmed parameters established from stack testing. The feedback signal indicates the degree and manner in which the boiler controller should adjust the forced draft (FD) fan damper settings. The FD fans are constant speed and air flow is controlled by variable vane inlet dampers. The FD fan damper setting is controlled by the boiler controller as a nominal damper percentage setting (i.e. percent open). The O_2 analyzer, DCS, boiler controller, and FD fan dampers encompass the O_2 trim system.

EPA reports an average uncontrolled NO_X emission rate of 0.53 pounds per million British thermal units (lb/MMBtu) for spreader-stoker boilers in Table 2-2 of the Alternative Control Techniques Document – NO_X emissions from industrial/Commercial/Institutional (ICI) Boilers. [EPA-453/R-94-022]. With the O_2 trim system, EUs 1 through 6 have an estimated NO_X emission rate of 0.3 lb/ MMBtu. Based on this data, the O_2 trim system achieves a control efficiency of approximately 43 percent compared to an uncontrolled spreader-stoker boiler.

Because an O_2 trim system is already in use, combustion control is a technically feasible NO_X emission control measure.

- **SNCR + Combustion Control**

SNCR + combustion control is a combination of two emission control techniques. When operated together, SNCR and combustion control offers increased destruction efficiencies than either option operated alone. SNCR and combustion control are described separately above. Because SNCR is not a technically feasible NO_X emission control option, SNCR + combustion control is not a technically feasible NO_X emission control option.

- **SCR + Combustion Control**

SCR + combustion control is a combination of two emission control techniques. When operated together, SCR and combustion control offers increased NO_X emission control efficiencies compared to either option operated alone. SCR and combustion controls are described separately above. SCR + combustion control is a technically feasible NO_X emission control measure.

NO_X Emission Control Effectiveness

EUs 1 through 6 are each rated at 230 MMBtu/hr of heat input with an estimated NO_X emission rate of 0.3 pounds per MMBtu (lb/MMBtu). Each boiler has the potential to emit 302 tons per year (tpy) of NO_X.

Table 3. NO_X Emission Control Technology Effectiveness

Emission Control Technology	Control Efficiency (pct.)	Estimated Annual Emission Reduction (tpy)
SCR + Combustion Control	80	242
SNCR + Combustion Control	Not Technically Feasible	0
SCR	80	Not Applicable[2]
SNCR	Not Technically Feasible	0
Combustion Control	0[3]	0[3]

[1] Each boiler (EUs 1 through 6) is estimated to emit 302 tpy on NO_X with existing combustion control system.
[2] The estimated annual emission reduction is not applicable because this control option is not evaluated without the already installed combustion control system.
[3] Combustion control is already installed. A change in control efficiency and emission reduction does not occur with this option.

Evaluate NO_X Emission Control Technologies

Appendix III.D.5.7 of the moderate $PM_{2.5}$ Nonattainment SIP (December 24, 2014) provides Individual Emission Unit RACT Determinations. NO_X control techniques for several emission unit types, including coal-fired boilers are listed in Table 1. NO_X Control Techniques (page Appendix III.D.5.7-70). DU believes the available emission control technologies listed in Table 1. NO_X Control Techniques to be incomplete for non-EGU boilers. DU also believes the cost effectiveness presented for coal-fired boilers in Table 1. NO_X Control Techniques is unreasonably low, particularly for coal-fired boilers operating in Alaska.

DU suggests that the 2010 Best Available Retrofit Technology (BART) Determination (Revised June 1, 2010) for GVEA Healy Unit 1 is more representative of NO_X emission control costs for coal-fired boilers in Alaska. Per Air Quality Permit No. AQ0173TVP02, Revision 1, Healy Unit 1 is a 327 MMBtu/hr pulverized coal wall-fired boiler constructed in 1967. The Technical Analysis Report (TAR) for Air Quality Permit No. AQ0173TVP02, Revision 1 indicates that Healy Unit 1 fires Usibelli coal, the same source of the coal fired in EUs 1 through 6 at FWA. Given the similar age, rating, general geographical location (Interior Alaska), and identical fuel source, DU believes Healy Unit 1 is a reasonably similar unit to EUs 1 through 6 for the purpose of estimating NO_X RACT cost effectiveness.

Table 6-1 of the 2010 GVEA BART determination provides total annualized costs for multiple NO_X emission control technologies, including SCR and SNCR. GVEA evaluated the costs of SCR and SNCR when used with existing combustion control consisting of low NO_X burners (LNB) and over-fired air (OFA).

Based on the cost effectiveness of SCR provided in Table 4, SCR is not economically feasible and is not determined to be RACT. For this analysis, DU did not evaluate energy or environmental impacts of SCR because the economic evaluation did not support SCR as RACT.

Table 4. Estimated NO_X Control Technology Cost Effectiveness

Emission Control Technology	2010 GVEA BART Cost Effectiveness ($/ton)	Proposed FWA RACT Cost Effectiveness ($/ton)
SCR + Combustion Control	$15,762[1]	$17,417[2]
SNCR + Combustion Control	$4,208[3]	Not Applicable[4]
Combustion Control[5]	Existing	$0

[1] The 2010 GVEA BART analysis provides annualized costs for SCR + existing combustion controls (LNB/OFA).
[2] The FWA RACT Cost Effectiveness was determined by adjusting the 2010 GVEA BART analysis SCR cost by an inflation rate of 10.5 percent for the period of 2010 through 2016 per the U.S. Bureau of Labor Statistics. Additional costs to relocate the existing paved road, relocate buried utilities, and redesign the storm drainage system are anticipated (assuming relocation is feasible), but are not included in the Proposed FWA RACT Cost Effectiveness value. As a result, this cost effectiveness estimate may be conservatively low for the FWA boilers.
[3] The 2010 GVEA BART analysis provides annualized costs for SNCR + existing combustion controls (LNB/OFA).
[4] DU has determined that SNCR is not technically feasible for EUs 1 through 6 at FWA.
[5] EUs 1 through 6 at FWA are already equipped with combustion control consisting of O_2 trim systems.

A summary of the NO_X RACT determination is provided in Table 5. Other than combustion control, the NO_X emission control options are either technically or economically infeasible. As a result, combustion control is identified as NO_X RACT.

Table 5. Summary of NO_X RACT Determination

Air Pollutant	Available Control Technologies	Technically Feasible?	Economically Feasible?	Considered RACT?
NO_X	SNCR + Combustion Control	No	Not Applicable[1]	No
	SCR + Combustion Control	Yes	No	No
	SNCR	No	Not Applicable[1]	No
	SCR	Yes	Not Applicable[2]	No
	Combustion Control	Yes	Yes	Yes[3]

[1] SNCR was not evaluated for economic feasibility because SNCR is not technically feasible.
[2] SCR is not economically feasible per the control cost effectiveness presented in Table 4.
[3] EUs 1 through 6 at FWA are already equipped with combustion control consisting of O_2 trim systems.

DU appreciates the opportunity to provide updated NO_X emission control technology and cost data to ADEC to support the NO_X RACT analysis for the moderate $PM_{2.5}$ Nonattainment SIP.

Please contact Isaac Jackson at 907-457-1547 or at ijackson@doyonutilities.com or Courtney Kimball at 907-452-2280 or ckimball@slrconsulting.com with any questions.

Sincerely,

Shayne Coiley
Senior Vice President

cc: C. Kimball, SLR – Fairbanks, AK
D. Huff, ADEC APP, Juneau, AK
C. Heil, ADEC APP, Anchorage, AK

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APPENDIX F

FUEL TECH QUOTE FOR SNCR

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FUEL TECH

Technologies to enable clean efficient energy

guernsey

Fort Wainwright BACT Project

Selective NonCatalytic NOx Reduction
SNCR

For
Fort Wainwright Utilities Six (6) Coal Fired Boilers

Fuel Tech Proposal 17-B-038, Rev 0

April 27, 2017

27601 Bella Vista Parkway • Warrenville, IL 60555 • (P) 630.845.4500 • (F) 630.845.4501 • www.ftek.com

TABLE OF CONTENTS

TABLE OF FIGURES

1.0 EXECUTIVE SUMMARY

In support of Guernsey's charter to develop a BACT Report for the six (6) boilers at Fort Wainwright Utility complex, Fuel Tech, Inc. (FTI) is pleased to present our proposal for the Selective Noncatalytic NOx Reduction (SNCR) requirements for the target boilers. The proposed SNCR system performance and preliminary system design are based on the drawings, turning reports, Boiler Data Sheets, baseline NOx and target conditions provided by Guernsey.

Given that no technical specifications or commercial requirements were provided by Guernsey, we have based our proposal on Fuel Tech's standard equipment scope of supply and our standard terms and conditions, which are included in this proposal.

Guernsey and FTI decided to develop six (6) stand-alone SNCR systems for each boiler, without consideration of any shared components that may be possible. One (1) common urea storage tank will provided to supply reagent to all boilers.

Urea solution is the recommended reagent for the proposed SNCR system for following reasons:

1. In grate fired boilers targeting the reagent is critical for optimum NOx reduction performance. Urea solutions can be targeted, and any ammonia system cannot.
2. Ammonia slip requirements of 10 ppm less can only be achieved with a targeted urea based SNCR.
3. Safety advantages of storing and transporting urea to Fort Wainwright.
4. Urea can be provided in a solid form and solutionized on site. Ammonia would have to trucked as a solution form the lower 48 via barge, then trucked to Fairbanks.

In consideration of urea solution, urea solutions are not commercially available in Fairbanks, so the urea solution must be created at site via urea prill/granular solutionizing. The local utility, GVEA is currently operating a SNCR system (provided by FTI) at their Healy Power Plant south of Fairbanks and solutionizes urea on site in Healy. GVEA brings the urea into Fairbanks in one ton Supersacks for storage prior to shipping to Healy, so the logistics of solid urea supply to Fairbanks has been established.

FTI will provide the scope of supply and price for a solutionizer system, which will match the system provided for GVEA in this proposal.

Please refer to the Process Design Table in Section 5 for the SNCR performance details associated with the NOx reduction and urea consumption rates. Brochures covering Fuel Tech's APC General Capabilities and the NOxOUT SNCR Process can be found in Section 14, along with the Marketing Drawings referenced in this proposal.

2.0 NOxOUT® SNCR SYSTEM OVERVIEW

The proposed NOxOUT SNCR system in this proposal will include both the SNCR process and the Solutionizer. The SNCR process will be designed to control the flow of cooling/atomizing air, concentrated (50%) urea – commonly referred to as NOxOUT A – and urea dilution water being directed to the injectors such that the level of NOx reduction performance stated in the Process Design Table (see Section 4) is maintained across the selected load range.

The NOxOUT SNCR systems are comprised of several subsystems which may be broken down to the following major components:

- Concentrated Common, Urea Storage Tank (20,000-gallon capacity).
- A common Urea solution circulation module, providing reagent to feed to each boiler.
- PLC control module with Urea Dilution and Metering for each boiler.
- Distribution Modules for each boiler.
- Two (2) Zones of four (4) NOxOUT Injectors, for each boiler.

The Solutionizer system also has a few subsystems that can be broken down as follows:

- Supersack Hoist to Lift and Unload the bags.
- Auger feed of urea solid to the Solutionizing Tank.
- Solutionizer Mixing tank and Control Module.
- Transfer Pump to Common SNCR Storage Tank.

A typical Process Schematic reflecting the proposed SNCR system arrangement is included below. The 50% urea from the Solutionizer would be stored in one of our standard FRP tanks. The urea solution would be under constant circulation which will provide feed to each of boiler dedicated SNCR Metering Modules. There will be four (4) injectors per level rather than six as shown below in Figure 1.

Referring to Figure 1, below it is important to note that the tank will be the primary heating source for the concentrated urea. The pad heaters sandwiched between layers of the FRP tanks act as the heat source and are designed to maintain a temperature of 75 - 80°F to ensure that the urea stays safely above its crystallization temperature (~65°F). The Solutionizer will provide warm urea to the Storage Tank and pads will maintain that heat. We assume the tank will be indoors, but this is Alaska and general warehouse open area can get cold. The common circulation line should be heat-traced and insulated. The balance of piping from the metering modules should be insulated.

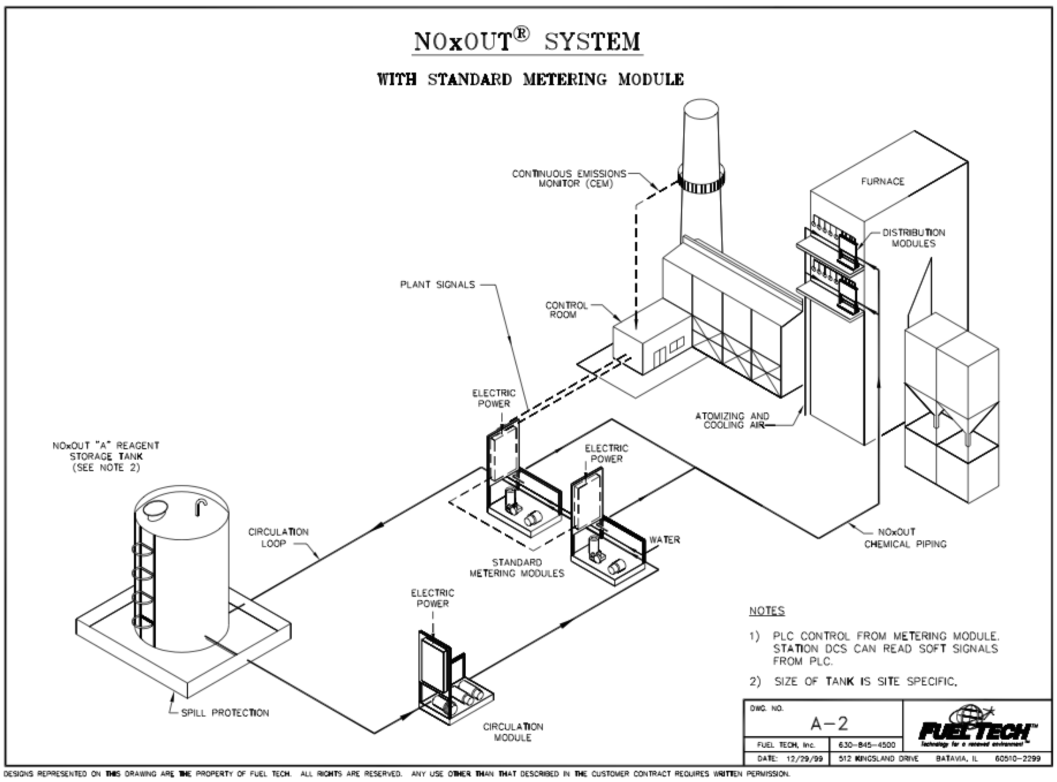


Figure 1 – SNCR Process Schematic

The quality of the urea that is used for the SNCR process is determined by the quality of the dilution water that is available – this relationship is illustrated in the tables we have included in Section 11. If high purity water is available – essentially demineralized quality water – an Industrial grade of urea can be used, which translates into operating cost savings.

The NOxOUT injectors would likely be installed be arranged in two zones, most likely with a pair of injectors on each side of the unit above the grate and fireball and below the furnace exit. Due to the importance of maintaining air pressure to the NOxOUT injectors, a dedicated source or a reliable source of air with a source pressure of 80-100 psig is recommended. The air pressure at each injector will be controlled to 35-45 psig.

The Solutionizer process starts with charging the Solutionizer Tank with water and heating the water the required temperature. When the Tank is ready, operators start lifting the bags and transfer the material into the tank. FTI is proposes a 12,000-gallon Tank for a 10,000-gallon batch of 50% urea. Based on the typical demand, shown on the Process Design and all boilers running the daily demand would be about 1500 gallons per day (seven (7) tons/supersacks per day). FTI understands this will be exception to the rule of how often the boilers actually run, but this design will be capable to fully supply the highest demand, which would be a batch every seven days.

Referring to Figure 2, the solids removed from the supersacks will be auger feed to the tank. The process will be programed to run until all of urea is dissolved and reach the desired concentration, by measuring specific gravity. Once completed, the solution is transferred to 20,000-gallon storage tank.

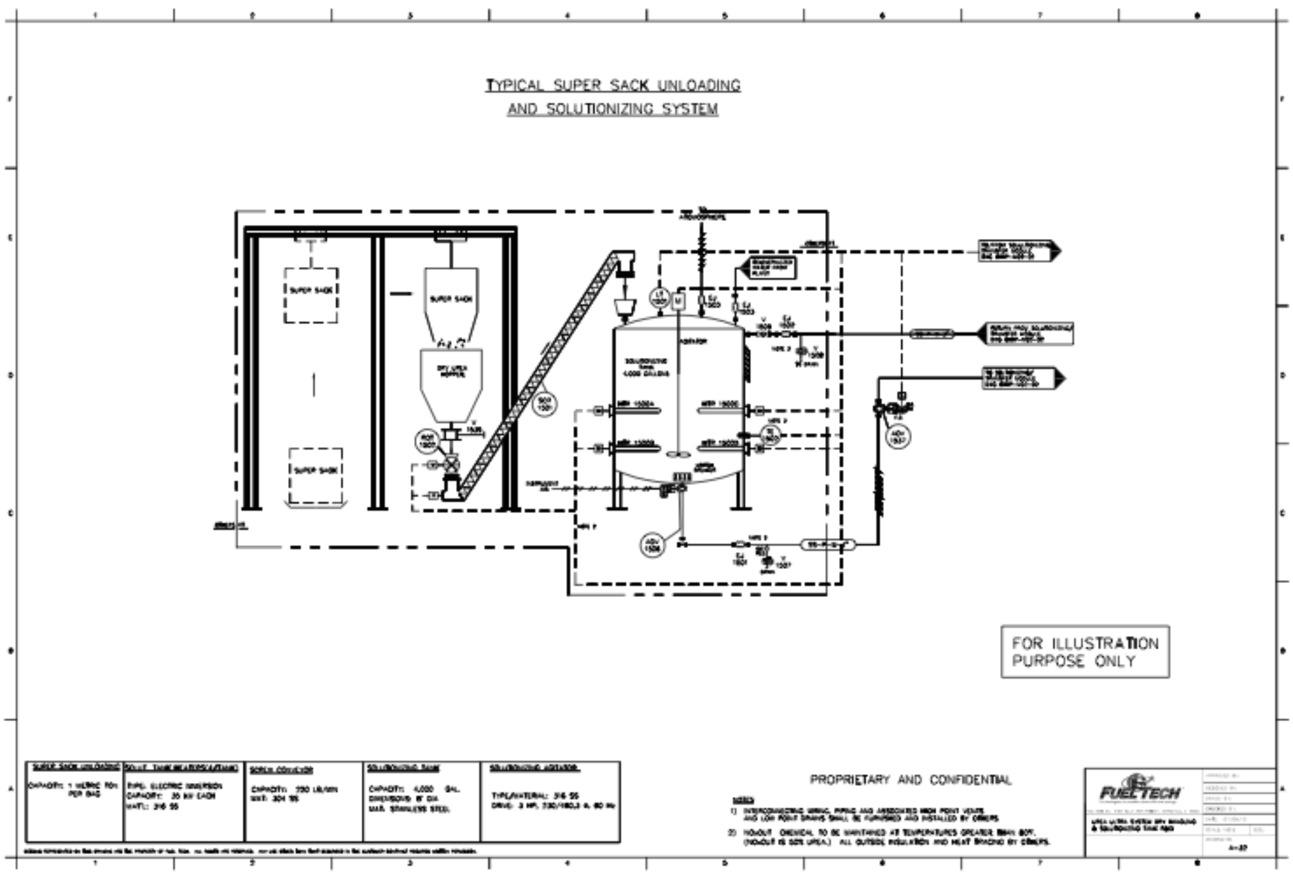


Figure 2 – SNCR Urea Solutionizer Schematic

3.0 NOxOUT® SNCR PROCESS DESIGN

The SNCR Process is a post-combustion NOx reduction method that reduces NOx through the controlled injection of reagent into the post-combustion flue gas path. The reagent recommended for this application is a 50% aqueous urea solution, which would be diluted with water having an appropriate quality prior to injection. Depending on the water quality, a stabilized urea formulation may be recommended to deal with potential issues associated with total water hardness.

The use of urea for control of oxides of nitrogen was developed under the sponsorship of the Electric Power Research Institute (EPRI) between 1976 and 1981. Fuel Tech once held the exclusive license from EPRI covering the commercialization and advancement of this NOx reduction technology. These early investigations provided fundamental thermodynamic and kinetic information for the NOx-urea reaction chemistry and identified minimal traces of reaction by-products. The predominant reaction is described by:

$$NH2CONH2 + 2NO + \frac{1}{2} O2 \Rightarrow 2N2 + CO2 + 2H2O$$

Urea + Nitrogen Oxide + Oxygen ⇨ Nitrogen + Carbon Dioxide + Water

Through some trace quantities of ammonia and carbon monoxide may form, the level of by-products produced can be minimized through proper application of the process.

The NOx removal efficiency and reagent utilization are related by a variable known as the Normalized Stoichiometric Ratio (NSR). This ratio is defined as shown below. The reagent utilization is equal to the NOx reduction divided by the NSR.

$$NSR = \frac{\text{Actual Molar Ratio of Urea to Baseline NOx}}{\text{Theoretical Ratio to Reduce One Mole of NOx}}$$

Fuel Tech has advanced the original, licensed technology by developing and refining chemical injection hardware, widening the applicable temperature range, and gaining process control expertise as a result of many commercial applications.

The SNCR Process is designed with the aid of computational fluid dynamics (CFD) and our chemical kinetic model (CKM). The CFD model simulates flue gas flows and temperature inside the furnace while the CKM calculates the reaction between urea and NOx based on temperature and flow information from the CFD model. A combination of these two models determines the optimum temperature region and the injection strategy required to effectively distribute the reagent. Recent technology advancements enable Fuel Tech to apply 3D visualization techniques to evaluate rapidly changing operating conditions and their impact on the SNCR process in real time.

Chemical injectors developed by Fuel Tech facilitate the reagent distribution. These injectors use compressed air or specially designed tips to atomize and direct the diluted urea into the post-combustion gas path. The droplet size distribution produced by the injectors promotes efficient contact between the urea and the NOx in the flue gas. This provides the unique targeting of reagent to the desired location in the upper furnace.

Two key parameters that affect the process performance are flue gas temperature and reagent distribution. The NOx reducing reaction is temperature sensitive, typically occurring between 1600°F and 2200°F. By-product emissions (NH3 slip) may become significant at the lower end of this range while chemical utilization and NOx reduction decrease at the higher end of the temperature range. It is important to note that this optimum temperature range is specific to each application. The reagent must be distributed within this optimum temperature zone to achieve the best performance.

The figure below helps illustrate the NOx reduction versus temperature challenge that SNCR faces. If it were possible to release the chemical (after injection and droplet evaporation) at a nominal temperature of 1800°F and provide sufficient residence time for the reactions, NOx reduction via SNCR can be a very efficient process.

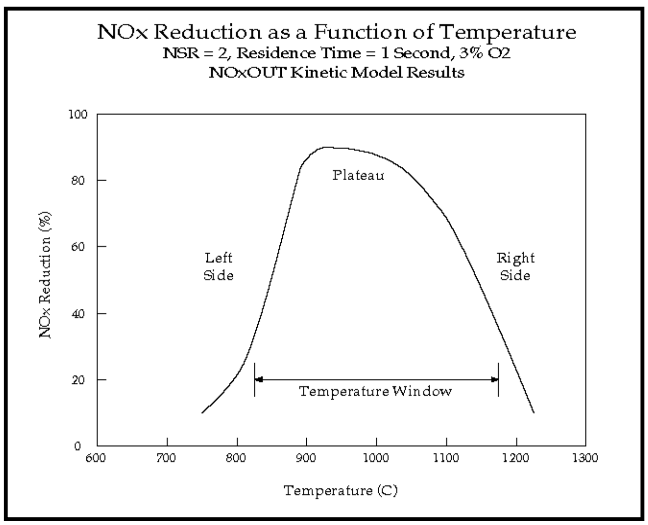


Figure 3 – NOx Reduction as a Function of Temperature

The SNCR Process is designed with the aid of in-house computational fluid dynamics (CFD) modeling and a proprietary chemical kinetic model (CKM) subroutine. The CFD model simulates flue gas flows and temperature in the upper furnace while the CKM calculates the reaction between urea and NOx based on temperature and flow information provided by the CFD model. A combination of these two models determines the optimum temperature region and the injection strategy required to effectively distribute the reagent and reduce NOx. Recent technology advancements enable Fuel Tech to apply 3D visualization techniques to evaluate rapidly changing operating conditions and their impact on the SNCR process in real time.

In the back block of the NOxOUT injector body, water encapsulated, air atomized droplets are formed and are then directed into the flue gas flow. The injector tips shape the flow and droplet momentum carries the reagent into the targeted region of the furnace where the urea decomposes and ultimately reacts with the NOx molecules. The final spray characteristics and flow rate of diluted reagent for each injector are fine-tuned during system optimization and startup to correspond to each unit's boiler operating loads, fuel combinations, and uncontrolled NOx concentrations.

Using a feed forward signal such as unit load, the NOx emission rate signal from the CEMS or a NOx process control monitor as feedback, and the system settings established during the optimization process, the SNCR system runs in the background via communication with either a PLC or the plant Distributive Control System (DCS) and is transparent to the other plant operations.

4.0 SNCR PROCESS CONTROL

Fuel Tech's NOxOUT SNCR process is controlled by logic that is programmed into an on-board PLC or customer-supplied DCS. In either case, the baseline testing (or OEM design basis) and CFD/CKM modeling provide guidance for the SNCR process optimization that takes place after the initial startup. The computer modeling correlates critical parameters such as Baseline NOx, CO, flue gas temperature, residence time, and flue gas velocity with a given MW load or steam flow, which serve as the Feed Forward signal shown in the graphic below.

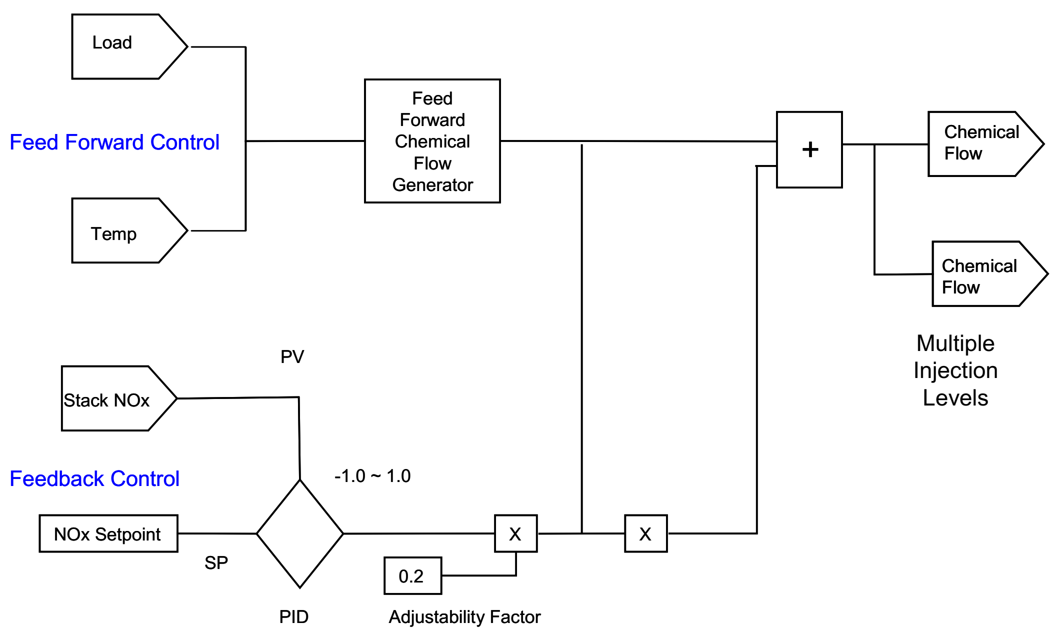


Figure 4 – SNCR Process Control

Based on guidance provided by our computer modeling and ultimately the optimization process, a set of Control Tables are populated for each injection zone – this is the "logic" mentioned above. These Tables associate a range of Feed Forward signals (e.g., 50-100% MCR) with a specific flow rate of concentrated urea (gph), dilution water pressure (psig), atomizing air pressure (psig), and NOx Setpoint values (lb/MMBtu), and tell the SNCR system which level or levels are in-service at a given load. The NOx Setpoint is the reference control value for the SNCR process derived from the testing and modeling.

Once the SNCR process is set to operate in "Auto" and the unit satisfies the system permissive to operate, meaning a minimum flue gas temperature has been reached that will facilitate the temperature-driven NOx reducing reactions, urea injection commences. As long as the unit load remains above the permissive level, the PLC or DCS will tell the

DW/MM Module to adjust the urea and dilution water flow rates to the Control Table values that match the load. The system then looks at the CEMS NOx emission rate – the Feedback Signal in the graphic – and as long as the CEMS NOx value is lower than the NOx Setpoint, the Metering Module control valves adjust the urea and water flow rates slightly downward based on a NOx Trim Constant (5% or 10% as an example) programmed into the PID loop. If the CEMS NOx starts to trend higher, the control valves adjust the flow rates higher as the system tries to satisfy the SNCR system NOx Setpoint. Automatic and continuous adjustments to the flow rates are made as the load changes, as directed by the Control Tables. If at any time the Feed Forward signal drops below the permissive level, the SNCR system goes into an "Idle" mode until the permissive is again satisfied.

It is also important to note that the NH3 slip typically is measured at the boiler outlet during the optimization process to ensure that only a minimum amount of unreacted ammonia is allowed to escape the SNCR process boundary as this automatic process continues. If available from an online optical or acoustic pyrometer, the Furnace Exit Gas Temperature (FEGT) that corresponds to that MW load or steam flow augments the Feed Forward signal. Temperatures lower than the set point would direct the process to bias the injection closer to the combustion zone while a temperature above the set point would move the injection away from this zone.

In the absence of a CEMS for SNCR Process feedback, the SNCR system can provide reliable and consistent NOx reduction performance across the tested operating range utilizing the feed forward signal and lookup tables contained in the PLC or DCS logic, though system operating costs are better controlled with the use of a feedback signal.

5.0 PROCESS DESIGN TABLE

The Process Design Table displays the expected NOx reduction performance for the conditions note below. The temperature and CO values were based on assumption and experience as well as input data provided by Guernsey. The Tuning Reports provided by Guernsey showed CO values of 200 ppm at 3% O2 at the stack and the expected CO in the furnace will be higher as noted in the Table below. If the actual temperatures and CO values are lower, it will improve chemical utilization and decrease the NOxOUT A demand noted below. This design represents close to a worst-case scenario.

Process Design Table			
Fort Wainwright BACT Project			
Type of Unit		Six (6) Detroit Stocker Grate Boilers	
Type of Fuel		Subbituminous Coal	
Case		Full Load, 150 tph	Typical Load, 100 tpd
	Units		
Load	MMBtu/hr	230	169
Baseline NOx	lb/hr	69	51
Baseline NOx	lb/MMBtu	0.30	0.30
Target NOx	lb/MMBtu	0.20	0.20
NOx Reduction	%	33.3	33.3
Average NH3 Slip	ppm	10	10
Average Flue Gas Temp	F	2000	1800
Furnace CO Limit	ppm	500	300
Furnace Velocity	ft/sec	13.6	8.9
NOxOUT A (50% urea)	gph	23	9.8
Injectors		Two (2) Zones, Four (4) low flow injectors per Zone	

6.0 DIVISION OF RESPONSIBILITY

	Supplier	Buyer	Optional
Design and Engineering			
Kickoff Meeting Support	X		
Project Management	X		
Process Flow Diagram	X		
Piping and Instrument Diagrams	X		
Electrical Drawings	X		
PLC Programming	X		
General Arrangement Drawings	X		
Equipment General Arrangement Drawings	X		
Quality Control Plan and Execution	X		
Spare Parts List – To Follow	X		
Operations and Maintenance Manual	X		
Training Manuals and Presentation	X		
Installation Engineering		X	
NOxOUT® SNCR Equipment			
Urea Storage Tank	X		
Urea Dilution and Metering Module	X		
Diluted Urea Distribution Module	X		
Urea Solutionizing System	X		
Low Flow Injectors	X		
Injector Retract Mechanism (if required)	X		
Wire and Pipe within Battery Limits of Individual Equipment Furnished by Fuel Tech	X		
Motor Control Center, Starters, and Power Distribution Equipment		X	
Wire and Pipe to Connect and Interconnect Equipment Furnished by Fuel Tech		X	
Anchor Bolts		X	
Foundations		X	
Installation and Erection		X	
Spare Parts for Commissioning	X		
Spare Parts for Operation for Two (2) Years			X

	Supplier	Buyer	Optional
Utilities (see **Scope of Supply by Others** for expected values)		X	
Commissioning, Training, and On-Site Support			
Equipment Commissioning, Tuning, and Training			X
Installation/Erection Technical Support			X
Freight			
FOB Point of Manufacture	X		

7.0 NOxOUT® SNCR EQUIPMENT SCOPE OF SUPPLY

7.1 SNCR Equipment Summary

	Quantity
FRP Urea Storage Tank	1 × 20,000 gallons
Truck Off-loading Panel	1
CM-HP Circulation Module	1
DW-MM-LF 2Z Urea Dilution, Metering and Control Module	6
	Diluted Urea & Atomizing/Cooling Air Distribution Zone 1 & 2 NOxOUT Wall Injectors
Distribution Module (DM-NX-4)	12
NOxOUT Injector (INJ-NX)	48
	Solutionizer
Supersack dry urea unloading Module	1
10,000 gallons Solutionizing Tank and Mixer	*1*
Solutionizing Control Skid and Transfer Pump	*1*
	Additional Equipment and Services
PLC Programming	As Required
Process and Project Engineering	Included
CFD and CKM Modeling - AFS Design Basis	Included
Freight	FOB Point of Manufacture
Spare Parts for Commissioning	Included
Spare Parts for Two Years' Operation	OPTIONAL
On-site Installation Technical Assistance	See Exhibit C-1 for Per Diem Rates
Startup, Optimization, & Training Support Man-days	See Exhibit C-1 for Per Diem Rates

7.2 FRP Urea Storage Tank

The Urea Storage Tank is a flat bottom, dome top vertical tank made from Fiberglass Reinforced Plastic. The tank can be furnished in a capacity of 5,000 gallons to 50,000 gallons. Where urea consumption or storage capacity requires, multiple tanks can be furnished and interconnected. Each tank is heated, insulated, shop assembled, and designed to contain a 30% to 50% urea solution. Tanks are fabricated per ASTM D3299, NEC, IEEE, and all applicable OSHA regulations. Site specific conditions such as low and high ambient temperature, maximum wind load, maximum snow load, and seismic conditions are used to custom-design tanks for a specific geographic location.

The FRP tank is designed to contain a urea based liquid at a temperature up to 120°F and a specific gravity up to 1.15.

The tank heating package consists of an array of 500 watt, 240 VAC heating pads oriented horizontally and arranged in multiple levels in uniform locations around the perimeter of the tank. Heating pads are mounted low on the tank in order to provide heating when liquid levels are low. For cases in which multiple levels of heating pads are used, they are independently controlled. Heating pads are controlled such that they will be enabled and energized only when liquid level is above the top of the heating pad. The quantity of heating pads furnished built into the tank is sufficient to maintain the urea at a minimum of 15°F above the urea's crystallization ('salt out') temperature at ASHRAE 99.6% heating design conditions. Each tank shall be furnished with a minimum of one full spare heating pad. The pads are covered by polyisocyanurate insulation (PIR or ISO) and the insulation is covered by a second layer of fiberglass and a gel coat to inhibit UV rays and to provide weather protection.

The tanks come standard with flanged connections for pump supply, pump return, tank level, tank temperature, tank fill, and one spare. Hold-down points are molded into the base of the tank. A screened gooseneck vent is included on the top of the tank and a side man-way is installed near the bottom of the tank for maintenance purposes. An NEC- and IEEE-compliant NEMA 4 tank heating junction box is pre-mounted to the tank. The following materials are also furnished with the tank and require field installation by others:

- Differential pressure level transmitter,
- Multiple, manual flanged SS isolation valves with extended handles for insulation,
- Flanged stainless steel expansion joints,
- Tank hold down lugs, and a
- Dual element Type J Tank Thermocouple with flanged stainless steel thermowell.

Bolts, brackets, and other hardware for installation are by others.
20,000 Gallon Capacity: 12'-8" Ø × 23'-08" SS Height; Approx. Empty Weight: 7,7000 lb.

Reference FTI Drawing C-1

7.3 Low Flow Urea Dilution and Metering Module (DW-MM-LF-2Z)

The Combination Dilution Water / Low Flow Metering Module is designed to control the flow of dilution water and precisely mix the concentration (50.5%) urea and supply the mixed chemical to the SNCR injectors at a rated controlled by the PLC and actual process conditions. The DW/MM Module consists of one (1) full-flow, multi-stage centrifugal pump to provide dilution water at the required pressure to the control valve, and deliver mixed chemical at the required pressure, concentration and flow to the Distribution Module (DM). The DM provides individual control of the atomizing air and mixed chemical going to each injector.

The drawing we have included with this proposal shows 2×100% dilution water pumps, but the DW/MM Module we are proposing for this project does not have a redundant pump, though it can be provided at an additional cost, if required. The DW/MM Module also contains bronze simplex basket strainer for the water. The chemical is metered to each zone through the use of a control valve and magnetic flow meter. Other instrumentation includes various pressure gauges and a chemical water discharge pressure transmitter. The DW/MM module is controlled via an Allen-Bradley CompactLogix PLC and a PanelView 1500+ operator display with window kit.

This DW/MM Module is constructed on an open frame, stainless steel base in full compliance with ASME B31.1. The pump motor is TEFC and the entire module is rated NEMA 4. The DW/MM Module contains two NEC- and IEEE-compliant panels. One control panel houses the 480 VAC, 3 phase equipment, including the required disconnects, motor starter and motor protector for the Water Pump, and the second control panel houses the Allen-Bradley CompactLogix PLC, all 120 VAC, single phase equipment, all 24 VDC equipment including a convenience outlet for PLC programming and Ethernet network hub, and the PanelView 1500+ operator display with window kit.
Typical size: 4’ W × 10’ L × 6.5’ H; Approximate Weight: 2,500 lb.
Please note that taking into account the panels, the total width of this module is 60”.
Reference FTI Drawing E-8

7.4 Circulation Module

The High Pressure Circulation Module is designed to continuously circulate the NOxOUT®A chemical and to supply reagent to the Metering Module(s). Through the use of two full-flow, multistage SS centrifugal pumps, an in-line duplex strainer with pressure switch, and variable frequency drives, this system maintains a constant pressure of chemical in response to changing flow demands. The module includes a discharge line and return line pressure transmitter, local temperature indication and various pressure gauges. The module is controlled via an Allen-Bradley Compact Logix PLC and a Panelview 1500+ operator display with window kit.

The Circulation Module is constructed on an opened frame, stainless steel base in full compliance with ASME B31.1. The pump motors are TEFC and the entire module is rated NEMA 4. The module contains two NEC and IEEE compliant control panels. One control panel houses the 480 VAC, 3 phase equipment including the required disconnects, motor starters, and motor protectors. The second control panel houses the PLC, all 120 VAC, single phase equipment, and all 24 VDC equipment including a convenience outlet for PLC programming and Ethernet network hub.

Typical size: 4’W x 8’L x 6.5’H
Approximate weight: 1,500 lbs.
Reference Fuel Tech Drawing: D-1

7.5 NOxOUT Distribution Module (DM-NX-4)

The purpose of the NOxOUT® Distribution Module is to provide mixed chemical and atomizing air to individual NOxOUT Injectors. The module is typically installed near the injectors (usually at the same elevation). Chemical to the module is fed from the Fuel Tech Metering Module. Atomizing Air is typically fed from the plant air system. The Distribution Module outputs a pair of feeds to each injector consisting of one atomizing air line and one chemical line – these pairs are grouped together for ease of installation.

The module is constructed in full compliance with ASME B31.1 and includes complete assembly and testing, chemical and air pressure indication, and individual air pressure regulators for each atomizing airline. The pipe-manifold assembly is mounted to a stainless steel frame suitable for wall mounting.
DM-NX-4: 54” W × 12” D × 36” H – Approximate Weight: 400 lb.
Reference FTI Drawing F-1

7.6 NOxOUT Injector Assembly (INJ-NX)

The urea injector assemblies are installed at the furnace elevation determined by our process modeling with each appropriately sized and characterized for proper flows and pressures required to achieve the necessary NOx reductions. The injectors are constructed entirely of 316L stainless steel. The nozzle tip is a ceramic-coated 316L stainless steel. The cooling shield is typically 3/4” Inconel tubing or 316 stainless steel with ceramic coating (0.750” OD and 0.065” wall thickness). The inner atomization tube is typically 3/8” tubing with an adapter to accept different injector tips, with a standard length of 2.5 feet.

Each assembly includes Fuel Tech air atomized injector, adapter for insertion adjustment, coupler to attach to boiler support, quick-connects and 6’ long steel-braided flex hoses for both the chemical and atomizing air connections.
Reference FTI Drawing G-1

7.7 Control Room Interface

Control of the Metering Module is facilitated by a PLC-based control system utilizing an Allen-Bradley CompactLogix processor. This PLC controls the local operation of the Metering Module and the entire SNCR System as long as signals representing the required boiler parameters such as NOx, operating O2, and steam flow load are routed to the PLC. The PLC is programmed during the initial phases of the equipment construction and then fine-tuned during the start-up testing to respond to specific unit and operating conditions. Communication with the plant DCS can be conducted via Ethernet connection or as an Option, ControlNet or DeviceNet communications can be provided.

Operator interface at the Metering Module is handled by an A-B PanelView 1500+. This unit has a digital display which acts as the window to unit operation. From the PanelView Plus the operator can monitor all of the system performance as well as control the system and adjust the automatic operation at the various load conditions. This is accomplished through the use of the display screen and the attached keypad.

An additional (optional) PanelView may be provided for the plant control room. The additional PanelView HMI would work in parallel with the PanelView located on the Metering Module, providing the same degree of control for both the control room operator and the operator working on the side of the boiler. Connection of the PanelView in the control room requires connection to a 110V power supply and a single communication cable running from the Metering Module to the control room.

7.8 NOxOUT Urea Solutionizing System

The Solutionizing System consists of a 10,000-gallon Stainless Steel Mixing Tank, Metering Pump, Recirculation/Transfer Pump, Immersion Heaters (8 × 35 kW), Bulk Bag Discharge, Conveyer with Hopper (for dry urea loading into tank), Water Flow Instrumentation, Valves, and a Control Panel to control the batching process. The Solutionizer is a self-contained, batch make-up system designed to supply a 50% urea solution for on-site storage and process requirements.

The Bulk Bag Discharge and Conveying system is designed to lift and position one (1) ton Bulk Bags into a conveyor hopper for clean, dust free material transfer. The solutionizer system contains a recirculation/transfer SS centrifugal pump, metering pump, in-line heater, valves and all the pressure and flow instrumentation for local control and monitoring of the NOxOUT® Solutionizing System. This module is prepackaged and fully shop tested and is supplied on a painted steel freestanding frame base. The electrical components are designed to meet NEMA 4 or 4X rating and are assembled per the applicable NFPA, NEC and IEEE electrical codes and standards. All mechanical assemble including piping, valves, are per, specification B31.1. All wetted components and materials are manufactured of 304 or 316 stainless steel with the exception of the bronze duplex strainer. The standard piping size, as indicated in Figure 2 above, will accommodate pump flows up to 70 gpm – line sizing would be reviewed for site-specific conditions.

The bulk bag, Supersack, hoist and urea removal process is a SACMASTER™ model dedicated hoist bulk bag discharge system, with the following features:

- Design – Bags to be loaded via integral motorized hoist and trolley with
- independent control
- Flow aid – "Posi-Flow" adaptive paddles (Patent #618360)
- Bag lifting frame
- Framework – 3" x 3" square tubing to support feeder and bulk bag

- Framework rating – 4,000-pound bags (maximum)
- Enclosure rating – NEMA 1, wall-mount, with frame-mounting bracket
- Materials of Construction - Enamel-coated mild steel
- Paint - Gray, Standard
- PLC 110VAC, 50/60 Hz; (2) Inputs (12V-24V), (5) inputs (same as power supply)
- Riser Section - 36"
- Hoist type – Harrington two-ton, with motorized trolley
- Hoist motor – 1 HP, 460 VAC, 3 phase
- Hoist lift speed – 16 FPM
- Trolley motor – 1/4 HP, 460 VAC, 3 phase
- Trolley travel speed – 15 FPM
- Hoist and trolley control – NEMA 4 pendent control with 15' cable
- Air requirements – 80 PSI, 5 CFM; non-lubricated or lubricated air supply
- Agitation electrical requirements – 110/220V, 50/60 HZ, 1 phase
- Hoist electrical requirements – 460V, 50/60 HZ, 3 phase

8.0 FUEL TECH ENGINEERING SCOPE OF SUPPLY

8.1 Engineering

Fuel Tech will provide Project and Process Engineering and the following drawings and information:

- P&IDs
- Skid Arrangements
- Foundation Loads
- Injector Locations
- Electrical Drawings and Bill of Materials
- Pump Performance Curves

8.2 Engineering Services

- Computational Fluid Dynamics and Kinetic Modeling
- Project Engineering
- Start-up, Optimization and Training Field Services (See Exhibit C-1). *Note: there will a wide range of time required due to being in Alaska, and the degree each boiler has unique operations.*
- Operation and Maintenance Manual (One (1) Electronic Copy)

9.0 SCOPE OF SUPPLY BY OTHERS

1. Appropriate Fuel, Flue Gas, and Operating Data and Additional Drawings as Required to Confirm Injector Locations and Complete Process Design.
2. Installation of Fuel Tech Equipment, Interconnecting Piping and Wiring, Etc.
3. Installation Management and Supervision.
4. Structural and Platform Steel, Handrails, and Other Equipment and Instrument Access for Equipment Furnished by Fuel Tech.
5. Interconnecting Piping, Valves, Wiring, Wireways, and Other Materials Outside the Equipment Battery Limits.
6. Insulation and Covering.
7. Equipment Enclosures, if Required.
8. Equipment Components per Fuel Tech Standard Scope of Supply.
9. Foundation, Structural Steel Supports, and Design.
10. Foundations and Housekeeping Pads for Equipment Furnished by Fuel Tech.
11. Solid Urea Reagent Supply and Appropriate Dilution Water Quality and Solutionizer Make Up Water.
12. Utilities including Instrument Compressed Air, Plant Compressed Air, Urea, Dilution Water, Electric Power Supply including MCC and Starters, Control Power, Urea.
13. CEMS/NOx/Oxygen Analyzers and Calibration Gases, if Required.
14. Performance Testing.
15. Internal and External Scaffolding or Platforms.
16. Safety Equipment.
17. Spare Parts for Operation.
18. Construction Permits and All Other Applicable Permits.

9.1 Estimated Utility Requirements – Normal Operation

Power: Solutionizer, SNCR and Storage Tank

- 6 + (12 x 6) = 78 KW , 480 V / 60 HZ /3Ø – MM skid
- 297 KW 480 V / 60 HZ /3Ø for Dry urea handling and solutionizing tank/skid
- 1.2 x 6 = 7.2 KW, 120 V / 60 HZ / 1Ø
- 5 KW, 240 V / 60 Hz / 1Ø

Compressed Air: 15 scfm x 8 injectors x 6 units = 720 SCFM
Instrument Air: 18 scfm (100 psig @ 70°F)
Dilution Water: 5 gpm (60 psig @ 60°F), per operating boiler

10.0 TYPICAL PROJECT SCHEDULE

EVENT	RESPONSIBILITY	WEEKS FROM ORDER DATE
Receipt of Order	Buyer	0
Begin Project Design	Fuel Tech	1
Submit Preliminary P&ID Drawings	Fuel Tech	4
Customer Drawing Comments Received	Buyer	6
Complete Process Modeling	Fuel Tech	10
Submit Mechanical & Electrical Drawings	Fuel Tech	10
Customer Drawing Comments Received/Release for Procurement and Fabrication	Buyer	12
Begin Equipment Fabrication	Fuel Tech	14
Equipment Shipment	Fuel Tech	32
Equipment Delivery	Fuel Tech	33
Complete Equipment Installation	Buyer	TBD
Begin Start-Up & Testing	Fuel Tech	1-2 weeks after completion of installation
Begin Optimization	Fuel Tech	2-4 weeks
Compliance Testing	Buyer	TBD

Notes

1. Dates and durations subject to change based on contract release date and turnaround times for drawing approvals.
2. Accelerated schedules can be accommodated through close coordination with the client and their BOP engineer.

11.0 DILUTION WATER AND UREA QUALITY SPECIFICATIONS

11.1 SNCR Dilution Water Quality Specifications

Dilution Water Analysis	NOxOUT® A	NOxOUT® HP	Unstabilized Urea
Total Hardness as $CaCO_3$ (ppm)	< 450	< 150	< 20
"M" Alkalinity as $CaCO_3$ (ppm)	< 300	< 100	< 100
Conductivity (µmho)	< 2500	< 1000	< 1000
Silica as SiO_2 (ppm)	< 60	< 60	< 60
Iron as Fe (ppm)	< 1.0	< 1.0	< 1.0
Manganese as Mn (ppm)	< 0.3	< 0.3	< 0.3
Phosphate as P (ppm)	< 1.0	< 1.0	< 1.0
Sulfate as SO_4 (ppm)	< 200	< 200	< 200
Turbidity (NTU)	< 10	< 10	< 10
pH	< 8.3	< 8.3	< 8.3

11.2 Urea Quality Specifications

Property	NOxOUT® A	NOxOUT® HP	Unstabilized Urea
Density (g/ml, 25°C)	1.13 - 1.15	1.13 - 1.15	1.13 - 1.15
pH	7.0 – 10.8	7.0 – 10.8	7.0 – 10.8
Appearance, Color	Clear to Light Yellow	Clear to Light Yellow	Clear to Light Yellow
Crystallization Temperature [1]	64°F (18 degC)	64°F (18 degC)	64°F (18 degC)
Foam (after bottle is shaken)	Foam lasts > 15 sec	Foam lasts > 15 sec	Foam lasts > 15 sec
Free NH3	< 5000 ppm as NH_3	< 5000 ppm as NH_3	< 5000 ppm as NH_3
Biuret Content	< 5000 ppm as NH_3	< 5000 ppm as NH_3	< 5000 ppm as NH_3
Organic Phosphate	55-85 ppm as PO_4	22-40 ppm as PO_4	Not Applicable
Orthophosphate	< 6 ppm as PO4	< 6 ppm as PO4	< 2 ppm as PO4
Total Suspended Solids	< 10 ppm	< 10 ppm	< 10 ppm
Makeup Water, Total Hardness	< 450 ppm as $CaCO_3$	< 150 ppm as $CaCO_3$	< 20 ppm as $CaCO_3$
Note 1: All properties shown for are for 50% urea. At 32% concentration the crystallization temperature drops to 11°F.			

12.0 PRICING AND PAYMENT TERMS

12.1 SNCR System Budget Pricing

For the NOxOUT SNCR System and Engineering Services described herein, Fuel Tech is pleased to provide the following budgetary USD price, FOB Point of Manufacture, valid for 90 days from the date of this proposal.

NOxOUT SNCR System Equipment and Engineering for Six (6) Boilers, including common Tank and Circulation Module	*One Million Six Hundred Forty-One Thousand Dollars*	*$1,641,000.00*
NOxOUT Urea Solutionizer System Equipment and Engineering	*Six Hundred Seventy Thousand Dollars*	*$670,000.00*
Total Project Price	*Two Million Three Hundred Eleven Thousand Dollars*	*$2,311,000.00*

Note: Field Services have been excluded from the equipment pricing provided above. However, any field support man-days requested by the EPC or end-user will be priced in accordance with Exhibit C1 – Fuel Tech Service Pricing Schedule included in Section 13.2. Start-up, commissioning, and operator training is a typical supply for all FTI supplied systems and for the sake of the unknowns for the actual project management, project construction and division of labor, FTI excluded this price item for the BACT review.

12.2 Terms of Payment

10% Upon Receipt of Letter of Intent, Purchase Order, or Contract

10% Upon Submittal of Drawings to the Buyer for Approval

20% Upon Buyer's Release for Equipment Fabrication

20% Upon Submittal of Certified Drawings to the Buyer

30% Upon Date of Shipment of Equipment, or Thirty Days After Notification to Buyer that Equipment is Ready to Ship, Whichever Occurs First.

10% After Successful Completion of Acceptance Test or Six (6) Months After Receipt of Equipment, Whichever Occurs First.

13.0 TERMS AND CONDITIONS

13.1 Exhibit C3 – Fuel Tech, Inc. Standard Terms and Conditions

These terms and conditions shall be part of the attached proposal and shall become part of the contract entered into between FUEL TECH, INC. (Fuel Tech), and the Buyer. Deviations from these terms and conditions must be agreed to in a writing signed by Fuel Tech and the Buyer. Fuel Tech hereby gives notice of its objection to any different or additional terms or conditions unless such different or additional terms or conditions are agreed to in a writing signed by Fuel Tech and Buyer.

1. TERMS OF PAYMENT

   All invoices are payable net thirty (30) days from date of invoice. Buyer shall pay interest at the rate of ten percent (10%) per annum on all overdue amounts. Buyer shall pay all sales tax, use tax, excise tax, or other similar taxes.

2. DELAYS

   If shipments are delayed by Buyer, payment shall be due on and warranty coverage shall begin to run from thirty days after the original shipment date specified in the contract or thirty (30) days after notification to Buyer that equipment is ready to ship, whichever is earlier. Risk of loss shall pass to Buyer at the time that equipment is identified, and any costs caused by such delay shall be borne by Buyer.

   If shipments are delayed by Buyer, Fuel Tech will ship the equipment no later than sixty (60) days after initial notification to the Buyer that the equipment is ready for shipment. Buyer agrees either (1) to provide Fuel Tech an appropriate “ship to” address and to accept delivery or (2) pay reasonable storage charges for the equipment beginning sixty (60) days after initial notification to Buyer that equipment is ready to ship.

3. PERFORMANCE GUARANTEE

   Buyer warrants that the operating conditions of the Unit are those specified in the Process Design Table. Buyer is solely responsible for the accuracy of that operating condition information, and all performance guarantees and equipment warranties granted by Fuel Tech shall be void if that operating condition information is inaccurate or is not met. All performance guarantees and equipment warranties are conditioned on Buyer timely providing all of the equipment, materials, chemicals, utilities, and services that it has agreed to provide, on operating the Unit within the operating conditions specified in the Process Design Table, and on using reagent of license grade quality in the operation of the Unit.

4. EQUIPMENT WARRANTY

Fuel Tech warrants that the equipment it provides shall be free from defects in design, workmanship, and material at the time the equipment is delivered and for a period of twelve (12) months after initial operation, or eighteen (18) months from shipment of equipment, whichever occurs first. Fuel Tech does not warrant wear parts such as injection tips, cooling shields, pump diaphragms, check valves, solenoids, pump impellers, pump wear rings, pump seals, valve packing, and valve seats.

All warranties made by the manufacturer of the equipment (if that manufacturer is any entity other than Fuel Tech) shall be assigned by Fuel Tech to the Buyer, if such assignment is permissible by law and contract. Warranty coverage starts at shipment of equipment or thirty (30) days after notification to Buyer that equipment is ready to ship.

5. DISCLAIMER OF WARRANTIES

Fuel Tech warrants its equipment and the performance of its equipment solely in accordance with the equipment warranty and performance guarantee contained in this proposal and makes no other representations or warranties of any other kind, express or implied, by fact or by law. All warranties other than those specifically set forth in this proposal are expressly disclaimed. Notwithstanding anything to the contrary contained in this proposal, Fuel Tech shall have no obligation hereunder with respect to any equipment which (i) has been improperly repaired or altered; (ii) has been subjected to misuse, negligence or accident; (iii) has been used in a manner contrary to Fuel Tech's written instructions; (iv) is comprised of materials provided by or a design specified by the Buyer; or (v) has failed as a result of ordinary wear and tear. **FUEL TECH SPECIFICALLY DISCLAIMS ALL OTHER WARRANTIES, EXPRESS OR IMPLIED, AND DISLCAIMS THE IMPLIED WARRANTY OF MERCHANTABILITY, THE IMPLIED WARRANTY OF FITNESS FOR A PARTICULAR PURPOSE, AND ANY OTHER IMPLIED WARRANTIES OF DESIGN, CAPACITY, OR PERFORMANCE RELATING TO THE EQUIPMENT.**

6. LIMITATION OF LIABILITY

Buyer's sole remedy under Section 5 (equipment warranty) and Section 4 (performance guarantee) shall be to allow Fuel Tech, at Fuel Tech's option, either to repair, replace, or supplement the equipment to meet the performance guarantee, or, in the event that those options are either not feasible or such repairs, replacement or supplementation continue to fail to meet the warranties as determined by Fuel Tech on a commercially reasonable basis, then Fuel Tech will repay to the Buyer the purchase price of the defective work. NOTWITHSTANDING ANYTHING TO THE CONTRARY CONTAINED IN THIS PROPOSAL, FUEL TECH'S TOTAL LIMIT OF LIABILITY ON ANY CLAIM, WHETHER FOR BREACH OF CONTRACT, BREACH OF WARRANTY, TORT, NEGLIGENCE, STRICT LIABILITY, OR ANY OTHER LEGAL THEORY, FOR ANY LOSS OR DAMAGE

ARISING OUT OF, OR CONNECTED TO, OR RESULTING FROM THIS AGREEMENT, INCLUDING WITHOUT LIMITATION AMOUNTS INCURRED BY FUEL TECH OR BUYER IN ATTEMPTING TO REPAIR, REPLACE, OR SUPPLEMENT THE EQUIPMENT OR MEET A PERFORMANCE GUARANTEE PROVIDED BY FUEL TECH TO BUYER, IF ANY, SHALL BE LIMITED TO THE CONTRACT PRICE TO BE PAID BY BUYER PURSUANT TO THE CONTRACT.

7. EXCLUSION OF CONSEQUENTIAL DAMAGES

NOTWITHSTANDING ANYTHING TO THE CONTRARY CONTAINED IN THIS PROPOSAL, IN NO EVENT SHALL FUEL TECH BE LIABLE FOR ANY INDIRECT, CONSEQUENTIAL, INCIDENTAL, SPECIAL, OR PUNITIVE DAMAGES, INCLUDING BUT NOT LIMITED TO LOSS OF CAPITAL, LOSS OF REVENUES, LOSS OF PROFITS, LOSS OF ANTICIPATORY PROFITS, LOSS OF BUSINESS OPPORTUNITY, DAMAGE TO EQUIPMENT OR FACILITIES, COST OF SUBSTITUTE NOx REDUCTION SYSTEMS, DOWNTIME COSTS, GOVERNMENT FINES, OR CLAIMS OF CUSTOMERS, EVEN IF ADVISED OF THE POSSIBILITY OF SUCH DAMAGES.

8. RESPONSIBILITY FOR THIRD PARTIES

Buyer shall at all times be responsible for the acts and omissions of its subcontractors and of any other third parties hired or retained or contracted by Buyer to perform work or provide equipment related to the system provided by Fuel Tech, including but not limited to third party design, systems integration, equipment tie-in, or process design changes. Fuel Tech shall have no responsibility for ensuring the accuracy of any such work or the performance of any equipment provided by subcontractors or third parties hired or retained or contracted by Buyer, and Buyer assumes all liability for any such work or equipment and for any failures in Fuel Tech's equipment caused by any such subcontractors or third parties hired or retained or contracted by Buyer. Buyer agrees to indemnify, hold harmless, and defend Fuel Tech from any claims, losses, damages, injuries, or failures caused by any such subcontractors or third parties.

9. CONFIDENTIALITY

(a) "Confidential Information" means the confidential or proprietary designs, processes, trade secrets, and other information owned or controlled by Fuel Tech, embodied in or relating to Fuel Tech's design, construction and implementation of processes and systems for the reduction of NOx emissions from the specific combustion unit(s) for which Fuel Tech has been engaged to provide a technology solution (the "Site") by urea-based or ammonia-based NOx reduction processes including (i) non-catalytic, catalytic and combined catalytic and non-catalytic processes, (ii) urea treatment and handling processes and (ii) combustion or combustion modification. For avoidance of doubt, it is understood that Confidential Information may include, but is not limited to, such designs, processes, trade secrets and other information incorporated into Fuel Tech product offerings known as NOxOUT SNCR and ULTRA. The Know-How includes, but is not limited to: computational fluid dynamics modeling for the Site; design, construction and installation of chemical injection apparatus, control systems for monitoring and controlling chemical introduction and chemical composition of combustion effluents, chemical storage and delivery apparatus, and chemical mixing apparatus; business information relating to industry standards and regulatory matters and to sources of supply of chemicals and component equipment for reduction of NOx with effectiveness; and other aspects of chemical, metering, delivery, and control for efficient operation of the Site employing urea-based selective non-catalytic reduction or urea-based combined selective non-catalytic and catalytic reduction processes alone or in combination with combustion modification.

(b) Buyer agrees that it shall hold Confidential Information received from Fuel Tech in the strictest confidence, shall not use the Confidential Information for its own benefit except as necessary to fulfill the terms of the agreement between the parties, shall disclose the Confidential Information only to employees, agents, or representatives who have a need to know the Confidential Information, shall not disclose the Confidential Information to any third party, shall not copy the Confidential Information, shall not disassemble, decompile, or otherwise reverse engineer the Confidential Information and any inventions, processes, or products disclosed by Fuel Tech, and, in preventing disclosure of Confidential Information to third parties, shall use the same degree of care as for its own information of similar importance, but no less than reasonable care.

10. LICENSE AGREEMENT AND OTHER TERMS

For a period not exceeding the life of the Site, Contractor, as licensor, grants to Buyer, as licensee, a nonexclusive license of the Technology (as defined below) to use it for Buyer's internal use at the Site. Buyer shall have no right to make, sell, transfer, license, or sublicense the Technology except that Buyer may transfer the license to a purchaser of the Site. Buyer may use the Technology at the Site in conjunction with Buyer' normal operation, maintenance or repair of the Site. The Technology shall not be considered as Buyer's property under "work for hire" or any other legal theory or principle, nor shall Buyer claim to own or have the right to use any future improvement of the Technology. In addition to its other remedies at law or in equity, either party may terminate this license at any time upon written notice if the other party is in material breach of the confidentiality or license terms set forth in Sections 9 and 10 hereof and fails to cure such breach within thirty (30) days following written notice of such breach. For purposes of this Section 10, "Technology" means the Confidential Information described in Section 9 above and, if applicable, U.S. Patent No. 7,090,810.

11. INDEMNIFICATION

Each party to the Agreement ("Party" or collectively "Parties") shall defend, indemnify, and hold harmless the other Party and its employees, agents, and representatives from any third party claims, liabilities, lawsuits, costs, losses, or damages (collectively "Losses") that arise out of or result from any negligent or willful acts or omissions of the indemnifying Party's employees, agents, or representatives to the extent such Losses relate to personal injury or death or property damage ("Third Party Claims"). Where such Third Party Claims are the result of the joint or concurrent negligence or willful misconduct of the Parties or their respective agents, employees, representatives, subcontractors, or any third party, each Party's duty of indemnification shall be in the same proportion that the negligence or willful misconduct of such Party, its agents, employees, representatives, or subcontractors contributed to the Third Party Claims. The Party entitled to indemnity under this Agreement shall promptly notify the indemnifying Party of any indemnifiable Third Party Claims. The Party responsible for indemnification under this Agreement shall conduct and control the defense of the Third Party Claims. The Parties shall use their best efforts to cooperate in all aspects of the defense of any Third Party Claims. The indemnifying Party shall not be bound by any compromise or settlement made without its prior written consent.

12. FORCE MAJEURE

The Parties shall be excused from liability for delays in manufacture, delivery, or performance due to any events beyond the reasonable control of the Parties, including but not limited to acts of God, war, national defense requirements, riot, sabotage, governmental law, ordinance, rule, or regulation (whether valid or invalid), orders of injunction, explosion, strikes, concerted acts of workers, fire, flood, storm, failure of or accidents involving either Party's plant, or shortage of or inability to obtain necessary labor, raw materials, or transportation ("Force Majeure"). Any delay in the performance by either party under this Agreement shall be excused if and to the extent the delay is caused by the occurrence of a Force Majeure, provided that the affected party shall promptly give written notice to the other party of the occurrence of a Force Majeure, specifying the nature of the delay, and the probable extent of the delay, if determinable.

Following the receipt of any written notice of the occurrence of a Force Majeure, the parties shall immediately attempt to determine what fair and reasonable extension for the time of performance may be necessary. The parties agree to use reasonable commercial efforts to mitigate the effects of events of Force Majeure.

No liabilities of any party that arose before the occurrence of the Force Majeure event shall be excused except to the extent affected by such subsequent Force Majeure.

13. GOVERNING LAW

This Agreement shall be governed by and interpreted in accordance with the laws of the State of Illinois, excluding its choice of laws rules.

14. ENTIRE AGREEMENT

This Exhibit C3 and the Fuel Tech Proposal attached to it constitute the entire agreement between the parties and can be modified only in writing signed by authorized representatives of each of the parties.

13.2 Exhibit C1 – Fuel Tech Service Pricing Schedule

RATES

Billing will be based on rates in effect at time service is rendered. Rates apply within the USA, but excluding the States of Alaska and Hawaii. The per diem rates listed below are for an eight-hour man-day, during normal working hours. Travel time is working time. Parts and expenses are additional.

	Daily Rate	Hourly Rate
Technician	$1,425.00	$180.00
Project Engineer	$1,575.00	$195.00
Process/Test Engineer	$1,675.00	$210.00
Project Manager	$1,675.00	$210.00
Engineering Manager/Director	$2,075.00	$260.00
VP Technology	$2,275.00	$285.00

The rates quoted are valid through January 31, 2018. The per diem rate for specialist service and services performed outside the Continental United States will be quoted upon request.

NORMAL WORKING HOURS AND DAYS

8:00 A.M. to 5:00 P.M., including sufficient time for lunch, Monday through Friday, except legal holidays, at location of customer's plant.

OVERTIME

Overtime will be billed at 1.5 times the prevailing hourly rate. Overtime is defined as all hours worked under twelve (12) on the employee's first scheduled off day (Saturday), and all hours worked under twelve (12) and over eight (8) hours for a day on the job (Standard hourly rate X 1.5).

DOUBLE TIME

Double time will be billed at two (2) times the prevailing hourly rate. Double time is defined as all hours worked over twelve (12) on any day, all hours worked on the employee's second scheduled off day (Sunday) and all hours on observed holidays.

EXPENSES

1. TRAVEL
   a) Automobile travel at the rate of $0.54 per mile.
   b) Travel expenditures will be charged per round-trip from the Fuel Tech personnel's point of origin, plus local travel.
   c) Expenses for travel will be at cost, which will be by airplane, rail or auto, whichever is the most expeditious under given circumstances. Air travel will

be at prevailing available rates; Tourist Class within the Continental United States and Business Class for International flights.

2. LIVING
   a) Actual expenses for lodging, meals and incidental costs.
   b) Telephone calls and wires as required in connection with details of the job will be charged at cost.

GENERAL CONDITIONS

- Fuel Tech representatives are authorized to act in a consulting capacity only. Operation and control of all equipment shall rest with others. Fuel Tech shall not be held responsible for any damage through any misoperation or misunderstanding.

- Customer shall render all reasonable assistance to Fuel Tech representative. Necessary working and storage space, including field office, if required, shall be furnished by the customer. Customer shall be responsible for insuring the Fuel Tech representative has full access to the equipment to be serviced and the scheduling of the required boiler loading.

- It will be the responsibility of the customer to furnish qualified tradesmen when required, to work with our representative.

- In the event of any labor disputes, it shall be left to the judgment of the Fuel Tech representative on the jobsite as to their course of action. Fuel Tech's representative will in no way become involved in labor disputes.

SPARE PARTS

Spare parts are available through our Warrenville, IL office. An inventory of critical parts is kept on-site for injectors. Fuel Tech works with key local suppliers to provide quick turnaround for spare parts orders time. Parts and expenses are additional.

RENTAL EQUIPMENT

Customer shall, at its own cost and expense, keep the Equipment in good repair, condition, and working order and shall furnish any and all parts, mechanisms, and devices required to keep the Equipment in good working order. Customer hereby assumes and shall bear the entire risk of loss or damage to the Equipment from any and every cause whatsoever. In the event of loss or damage of any kind whatever to the Equipment, Customer shall, at Fuel Tech's option:

a) place the Equipment in good repair, condition, and working order; or
b) replace the Equipment with identical Equipment in good repair, condition and working order; or
c) pay Fuel Tech the replacement cost of the Equipment.

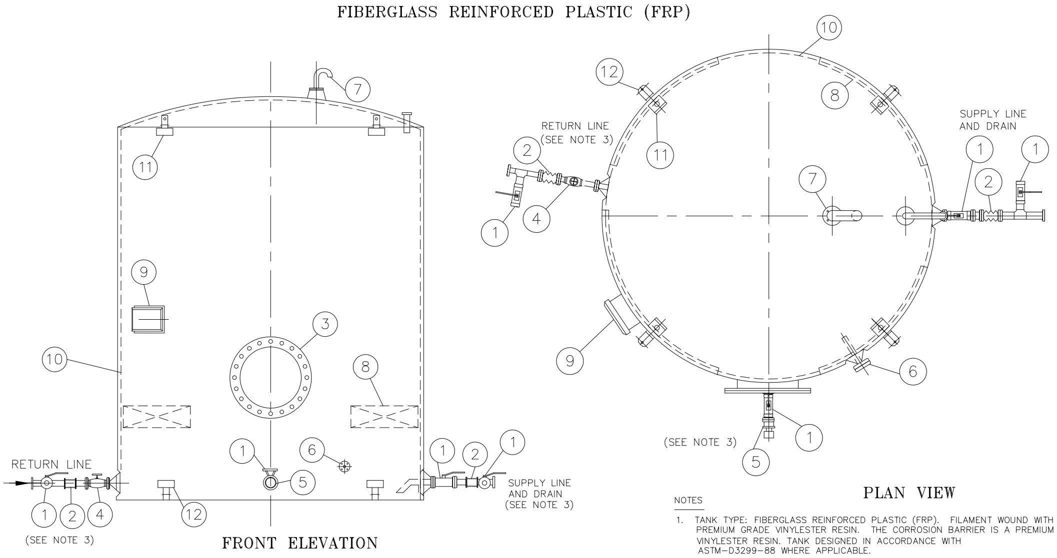
14.0 MARKETING DRAWINGS and GENERAL INFORMATION

NOxOUT and HERT SNCR Processes

- C-1 FRP Storage Tank
- D-1 Circulation Module
- E-8 Dilution Water Module
- F-1 NOxOUT Injector Distribution Module (DM-NX)
- G-1 NOxOUT Injector

NOxOUT® SYSTEM STORAGE TANK

FIBERGLASS REINFORCED PLASTIC (FRP)



NOTES

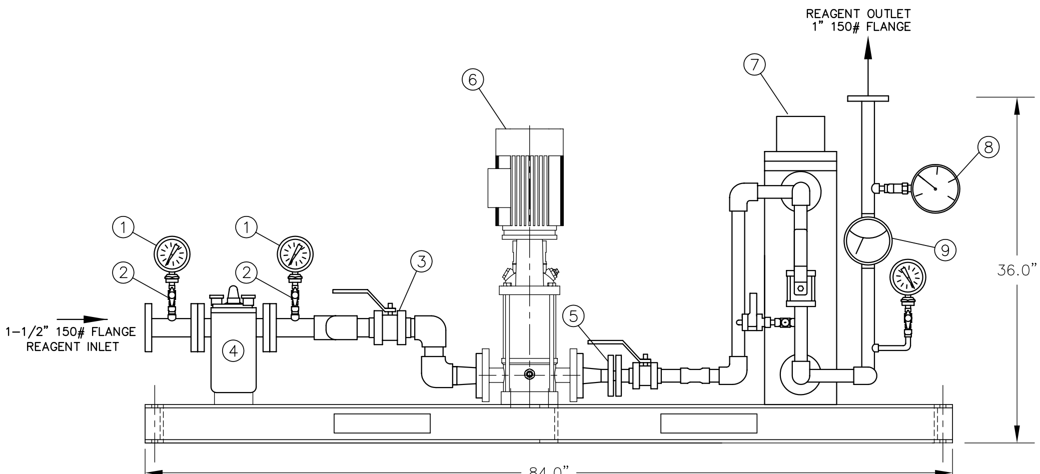
1. TANK TYPE: FIBERGLASS REINFORCED PLASTIC (FRP). FILAMENT WOUND WITH PREMIUM GRADE VINYLESTER RESIN. THE CORROSION BARRIER IS A PREMIUM VINYLESTER RESIN. TANK DESIGNED IN ACCORDANCE WITH ASTM–D3299–88 WHERE APPLICABLE.
2. PROVIDED WITH HOLD DOWN LUGS, LIFTING LUGS AND HEATING PADS. QUANTITIES AND LOCATIONS ON TANK ARE SITE SPECIFIC.
3. VALVES AND THEIR ASSOCIATED FITTINGS ARE SHIPPED LOOSE. TEMPERATURE ELEMENT AND LEVEL TRANSMITTER ARE ALSO SHIPPED LOOSE. CUSTOMER TO INSTALL THESE ITEMS. LOCATIONS ON TANK ARE SITE SPECIFIC.

ITEM	DESCRIPTION	ITEM	DESCRIPTION
1	BALL VALVE	8	HEATING PADS
2	EXPANSION JOINT	9	HEATER CONTROL BOX
3	COVERED MANWAY	10	INSULATION
4	GLOBE VALVE	11	LIFTING LUGS
5	LEVEL TRANSMITTER	12	HOLD DOWN LUGS
6	TEMPERATURE ELEMENT WITH THERMOWELL		
7	VENT		

Volume, Gallons	Diameter	Height	Empty Weight, Lbs	Full Weight, Lbs
6,000	10'	10'-03"	2,700	60,000
8,000	10'	13'-10"	3,400	80,000
10,000	10'	17'-01"	4,200	100,000
15,000	12'	17'-10"	5,300	148,000
20,000	12'	23'-08"	7,700	198,000
25,000	14'	21'-09"	8,500	246,000
30,000	14'	26'-01"	11,000	296,000
35,000	14'	30'-06"	14,000	347,000
40,000	14'	34'-10"	16,600	397,000
45,000	14'	39'-01"	20,000	448,000

DWG. NO.	C–1
REVISION: A	630–845–4500
DATE: 03/11/09	27601 BELLA VISTA PKWY WARRENVILLE, IL 60555

FUEL TECH NOxOUT CIRCULATION MODULE

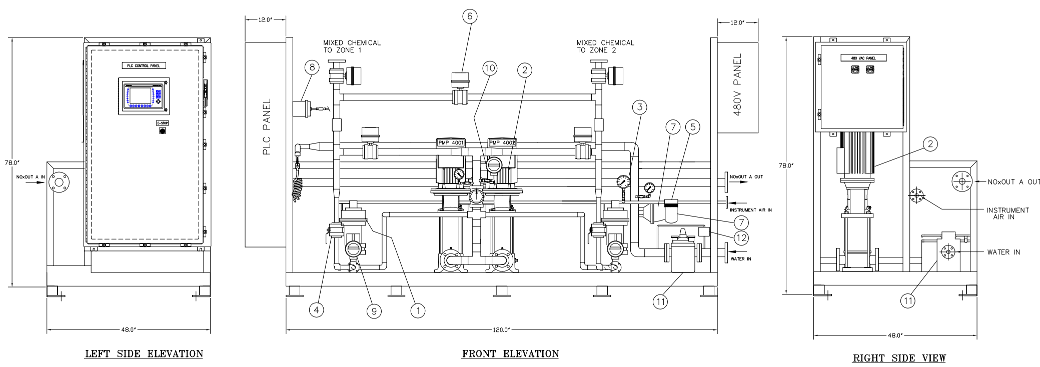


FRONT ELEVATION
(24" WIDE)

ITEM	DESCRIPTION	ITEM	DESCRIPTION
1	PRESSURE GAUGE	6	CIRCULATION PUMPS (2)
2	PLUG VALVE	7	IN-LINE HEATER
3	BALL VALVE	8	TEMPERATURE INDICATOR
4	DUPLEX STRAINER	9	FLOW SWITCH
5	CHECK VALVE		

DWG. NO. D-1		FUEL TECH Technologies to enable clean efficient energy
REVISION: A	630-845-4500	
DATE: 02/19/08	512 KINGSLAND DRIVE	BATAVIA, IL 60510-2299

COMBINATION DILUTION WATER HIGH FLOW METERING MODULE
DW-MM-HF-2Z

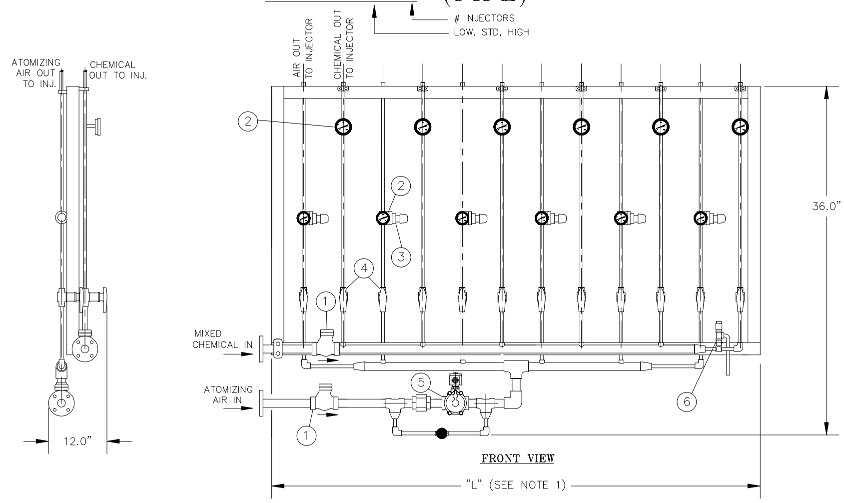


EST. WEIGHT: 3,000 LBS

ITEM	DESCRIPTION	ITEM	DESCRIPTION	ITEM	DESCRIPTION
1	FLOW CONTROL VALVE	5	AIR FILTER	9	MAGNETIC FLOW INDICATOR
2	WATER BOOST PUMP	6	MOTOR OP VALVE	10	PRESSURE TRANSMITTER
3	PRESSURE INDICATORS	7	WATER REGULATOR	11	DUPLEX BASKET STRAINER
4	BALL VALVE	8	AIR PRESSURE SWITCH	12	DIFFERENTIAL PRESSURE SWITCH

DWG. NO. E-8
FUEL TECH, Inc. 630-845-4500
DATE: 03/12/09 27601 BELLA VISTA PKWY WARRENVILLE, IL 60555

NOxOUT DISTRIBUTION MODULE
DM-NXa-b (PIPE)



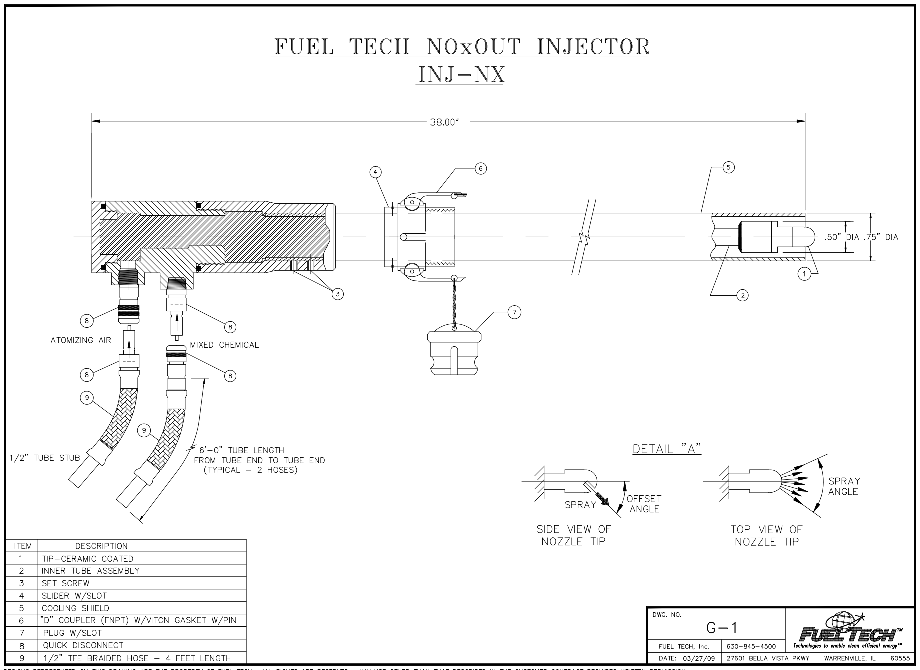
NOTES
1. "a" IN DM-NXa-b REPRESENTS THE TYPE OF NOxOUT INJECTOR: L-LOW FLOW, S-STANDARD FLOW, H-HIGH FLOW. IF "H" CHEMICAL LINE GOES TO ¾" LINE.
2. "b" IN DM-NXa-b REPRESENTS THE NUMBER OF INJECTORS. "L" REPRESENTS THE LENGTH OF THE MODULE WHICH IS DEPENDENT ON THE NUMBER OF INJECTORS. REFER TO TABLE 1 FOR SPECIFIC VALUES.

ITEM	DESCRIPTION
1	CHECK VALVE
2	PRESSURE INDICATORS
3	PRESSURE REGULATOR
4	BALL VALVES
5	SOLENOID VALVE
6	SAFETY RELIEF VALVE

TABLE 1

NO OF INJECTORS, X	3	4	5	6	7	8
LENGTH OF MODULE, "L"	41"	54"	67"	80"	93"	106"
WEIGHT OF MODULE	300#	400#	500#	600#	700#	800#

DWG. NO. F-1(PIPE)
FUEL TECH, Inc. 630-845-4500
DATE: 03/11/09 27601 BELLA VISTA PKWY, WARRENVILLE, IL 60555
FUEL TECH™ Technology for a renewed environment



ITEM	DESCRIPTION
1	TIP–CERAMIC COATED
2	INNER TUBE ASSEMBLY
3	SET SCREW
4	SLIDER W/SLOT
5	COOLING SHIELD
6	"D" COUPLER (FNPT) W/VITON GASKET W/PIN
7	PLUG W/SLOT
8	QUICK DISCONNECT
9	1/2" TFE BRAIDED HOSE – 4 FEET LENGTH

SNCR

NO_xOUT® and HERT™ Processes

Proven solutions for flexible, cost-effective NO_x reduction

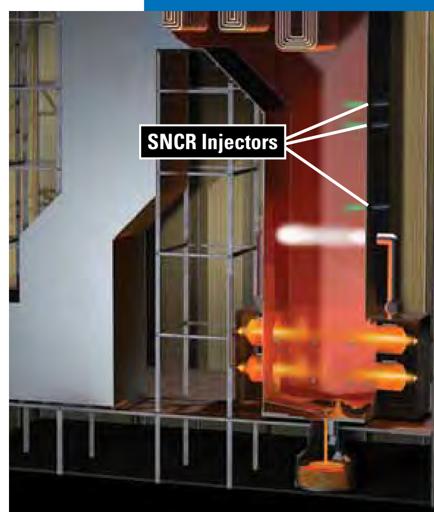
Fuel Tech's urea-based Selective Non-Catalytic Reduction (SNCR) Process is a post-combustion NO_x reduction method that reduces NO_x through a controlled injection of an aqueous urea solution into the combustion gas of utilized industrial sources including: fossil-fired units, waste-fired boilers, furnaces, incinerators, or heaters.

Fuel Tech has enhanced the basic SNCR technology by developing chemical injection hardware, widening the applicable temperature range, and applying process control expertise required for commercial applications.

Fuel Tech has two urea-based SNCR technologies: NO_xOUT® systems, which utilize low energy and air atomized injectors, and HERT™ High Energy Reagent Technology, which utilize mechanically atomized injectors and carrier air for injection into the furnace.

The NO_x-reducing reaction is temperature sensitive: the optimum temperature range is specific to each application. The reagent needs to be distributed within this optimum temperature zone to obtain the best performance.

The most commonly used reagent consists of a 50% urea solution. This reagent is readily available and requires no special safety precautions for handling.



SNCR Injection Process

SNCR Processes

Fuel Tech's SNCR Processes are designed with the aid of Computational Fluid Dynamics (CFD) and Chemical Kinetic Modeling (CKM) in addition to results from field tests. The CFD model simulates flue gas flows and temperature inside a unit while the CKM calculates the reaction between urea and NO_x based on temperature and flow information from CFD. The combination of these two models determines the optimum temperature region and the optimum injection strategy to distribute the reagent.

NO_xOUT® Process Injection ←	SNCR Technology	→ HERT™ High Energy Reagent Technology Injection
• High momentum injectors • Maximize performance • Adjustable for NO_x reduction downstream of injection point	• CFD/CKM Modeling • Reliable equipment • On-site optimization	• High energy, low momentum injectors • Maximize performance with minimal ammonia slip • Localized NO_x reduction

25-50% NO_x reduction

- Customized solution for each application
- Easy to retrofit – little downtime required
- Low capital cost
- Can be combined with other NO_x reduction technologies
  - 60-70% reduction with Combustion Modification
  - Up to 80% reduction as part of Fuel Tech's ASCR™ Advanced SCR process
- Safe reagent

FUEL TECH
Technologies to enable clean efficient energy™

APPENDIX G

SNCR COST MANUAL

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Air Pollution Control Cost Estimation Spreadsheet
For Selective Non-Catalytic Reduction (SNCR)

U.S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards
(May 2016)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Non-Catalytic Reduction (SNCR) control device. SNCR is a post-combustion control technology for reducing NOx emissions by injecting an ammonia-base reagent (urea or ammonia) into the furnace at a location where the temperature is in the appropriate range for ammonia radicals to react with NOx to form nitrogen and water.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SNCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SNCR control technology and the cost methodologoies, see Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated in 2016). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: http://www3.epa.gov/ttn/catc/products.html#cccinfo.

The spreadsheet can be used to estimate capital and annualized costs for applying SNCR, and particularly to the following types of combustion units:

(1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
(2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
(3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
(4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM). The size and costs of the SNCR are based primarily on four parameters: the boiler size or heat input, the type of fuel burned, the required level of NOx reduction, and the reagent consumption. This approach provides study-level estimates (±30%) of SNCR capital and annual costs. Default data in the spreadsheet is taken from the SNCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions, such as the boiler configuration and fuel type. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. For additional information regarding the IPM, see the EPA Clean Air Markets webpage at http://www.epa.gov/airmarkets/power-sector-modeling. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

Step 1: Please select on the ***Data Inputs*** tab and click on the ***Reset Form*** button. This will reset the NSR, plant elevation, estimated equipment life, desired dollar year, cost index (to match desired dollar year), annual interest rate, unit costs for fuel, electricity, reagent, water and ash disposal, and the cost factors for maintenance cost and administrative charges. All other data entry fields will be blank.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SNCR is for new construction or retofit of an existing boiler. If the SNCR will be installed on an existing boiler, enter a retrofit factor equal to or greater than 0.84. Use 1 for retrofits with an average level of difficulty. For the more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you selected coal, select the type of coal burned from the drop down menu. The NOx emissions rate, weight percent coal ash and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided.

Step 4: Complete all of the cells highlighted in yellow. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.015 and 0.03, repectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the ***SNCR Design Parameters*** tab to see the calculated design parameters and the ***Cost Estimate*** tab to view the calculated cost data for the installation and operation of the SNCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Coal

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.5

* NOTE: You must document why a retrofit factor of 1.5 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	230	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	7,600	Btu/lb
What is the estimated actual annual fuel consumption?	100,000,000	lbs/year
Is the boiler a fluid-bed boiler?	No	
Enter the net plant heat input rate (NPHR)	10	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Provide the following information for coal-fired boilers:

Type of coal burned: Sub-Bituminous

Enter the sulfur content (%S) = 0.13 percent by weight

or

Select the appropriate SO_2 emission rate: Not Applicable

Ash content (%Ash): 6.5 percent by weight

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost ($/MMBtu)
Bituminous	0	2.35	10.4	11,814	2.79
Sub-Bituminous	1	0.13	6.5	7,600	5.55
Lignite	0	0.91	14.3	6,534	1.85

Please click the calculate button to calculate weighted values based on the data in the table above.

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	219	days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.46	lb/MMBtu
NOx Removal Efficiency (EF) provided by vendor (Enter "UNK" if value is not known)	50	percent
Estimated Normalized Stoichiometric Ratio (NSR)	1.05	*The NSR value of 1.05 is a default value. User should enter actual value, if known.
Concentration of reagent as stored (C_{stored})	50	percent* *The reagent concentration of 50% is a default value. User should enter actual value, if known.
Denisty of reagent as stored (ρ_{stored})	71	lb/ft^3
Concentration of reagent injected (C_{inj})	50	percent
Number of days reagent is stored ($t_{storage}$)	30	days
Estimated equipment life	10	Years
Select the reagent used	Urea	

Plant Elevation: 450 Feet above sea level

Densities of typical SNCR reagents:	
50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3
19% aqueous NH_3	58 lbs/ft^3

Enter the cost data for the proposed SNCR:

Desired dollar-year	2016	
CEPCI for 2016	536.4	Enter the CEPCI value for 2016 — 584.6 2012 CEPCI — CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7	Percent
Fuel ($Cost_{fuel}$)	5.55	$/MMBtu
Reagent ($Cost_{reag}$)	1.62	$/gallon for a 50 percent solution of urea*
Water ($Cost_{water}$)	0.0201	$/gallon
Electricity ($Cost_{elect}$)	0.2671	$/kWh
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)	18.00	$/ton*

* The values marked are default values. See the table below for the default values used and their references. Enter actual values, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.015
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the the value used and the reference source . . .
Reagent Cost	$1.62/gallon of 50% urea solution	Based on vendor quotes collected in 2014.	
Water Cost ($/gallon)	0.0088	Average combined water/wastewater rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	Per Asish Agrwal 4/21/17, $20.1476/1000gal
Electricity Cost ($/kWh)	0.039	Average annual electricity cost for industrial plants is based on 2014 price data compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-861 and 861S, (http://www.eia.gov/electricity/data.cfm#sales).	Asish Agrwal 4/21/17, 0.2671$/kwh
Fuel Cost ($/MMBtu)	2.79	Weighted average cost based on average 2014 fuel cost data for power plants compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, "Power Plant Operations Report." Available at http://www.eia.gov/electricity/data/eia923/.	CHPP Jan 2016 report, $5.61
Ash Disposal Cost ($/ton)	18	Average ash disposal costs based on U.S. coal data for 2014 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Percent sulfur content for Coal (% weight)	0.31	Average sulfur content based on U.S. coal data for 2014 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	From table D 2.10 citing Coal data sheet at http://www.usibelli.com/Coal_data.php lists sulfur content at 0.12-0.28 percent.
Percent ash content for Coal (% weight)	10.40	Average ash content based on U.S. coal data for 2014 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	CHPP Jan 2016 report, 4.55
Higher Heating Value (HHV) (Btu/lb)	11,814	2014 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	D 2-7b from Doyon Tables, Usibelli.com/coal_data.php; 15.1 mmbtu/ton

SNCR Design Parameters

The following design parameters for the SNCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	230	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	265,105,263	lbs/year	
Actual Annual fuel consumption (Mactual) =		100,000,000	lbs/year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.00		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	0.23	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	1983	hours	
NOx Removal Efficiency (EF) =	(Noxin - NOxout)/Noxin =	50.00	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	52.90	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	52.440000	tons/year	
Coal Factor ($Coal_F$) =	1 for bituminuous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05		
SO_2 Emission rate =	(%S/100)x(64/32)*1E6)/HHV =	< 3	lbs/MMBtu	
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at 450 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.5	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.50		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Reagent Data:

Type of reagent used: Urea

Molecular Weight of Reagent (MW) = 60.06 g/mole
Density = 71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x NSR x MW_R)/(MW_{NOx} x SR) = (whre SR = 1 for NH_3; 2 for Urea	73	lb/hour
Reagent Usage Rate (m_{sol}) =	mreagent/Csol =	145	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	15	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x tstorage x 24)/Reagent Density =	11,001	gallons (storage needed to store a 30 day reagent supply)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i (1+ i)^n/(1+ i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.1424

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electrcity Consumption (P) =	(0.47 x NOx_{in} x NSR x Q_B)/NPHR =	5.22	kW/hour
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	0	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	0.07	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x 1E6)/HHV =	0.56	lb/hour

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	$2,311,000 in 2016 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0 in 2016 dollars
Balance of Plant Costs (BOP_{cost}) =	$1,995,520 in 2016 dollars
Total Capital Investment (TCI) =	$5,598,476 in 2016 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220{,}000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147{,}000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220{,}000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147{,}000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	$2,311,000 in 2016 dollars

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2016 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

Balance of Plan Costs (BOP_{cost}) =	$1,995,520 in 2016 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$136,546 in 2016 dollars
Indirect Annual Costs (IDAC) =	$799,616 in 2016 dollars
Total annual costs (TAC) = DAC + IDAC	$936,162 in 2016 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	$83,977 in 2016 dollars
Annual Reagent Cost =	$q_{sol} \times Cost_{reag} \times t_{op}$ =	$49,075 in 2016 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$2,765 in 2016 dollars
Annual Water Cost =	$q_{water} \times Cost_{water} \times t_{op}$ =	$0 in 2016 dollars
Additional Fuel Cost =	$\Delta Fuel \times Cost_{fuel} \times t_{op}$ =	$719 in 2016 dollars
Additional Ash Cost =	$\Delta Ash \times Cost_{ash} \times t_{op} \times (1/2000)$ =	$10 in 2016 dollars
Direct Annual Cost =		$136,546 in 2016 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$2,519 in 2016 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$797,097 in 2016 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$799,616 in 2016 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$936,162 per year in 2016 dollars
NOx Removed =	52 tons/year
Cost Effectiveness =	$17,852 per ton of NOx removed in 2016 dollars

APPENDIX H

SCR COST MANUAL

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Air Pollution Control Cost Estimation Spreadsheet
For Selective Catalytic Reduction (SCR)

U.S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards
(May 2016)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Catalytic Reduction (SCR) control device. SCR is a post-combustion control technology for reducing NO_x emissions that employs a metal-based catalyst and an ammonia-based reducing reagent (urea or ammonia). The reagent reacts selectively with the flue gas NO_x within a specific temperature range to produce N_2 and water vapor.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SCR control technology and the cost methodologies, see Section 4, Chapter 2 of the Air Pollution Control Cost Manual (as updated in 2016). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: http://www3.epa.gov/ttn/catc/products.html#cccinfo.

The spreadsheet can be used to estimate capital and annualized costs for applying SCR, and particularly to the following types of combustion units:

(1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
(2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
(3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
(4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM) (version 5.13). The size and costs of the SCR are based primarily on five parameters: the boiler size or heat input, the type of fuel burned, the required level of NOx reduction, reagent consumption rate, and catalyst costs. The equations for utility boilers are identical to those used in the IPM. However, the equations for industrial boilers were developed based on the IPM equations for utility boilers. This approach provides study-level estimates (±30%) of SCR capital and annual costs. Default data in the spreadsheet is taken from the SCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. For additional information regarding the IPM, see the EPA Clean Air Markets webpage at http://www.epa.gov/airmarkets/power-sector-modeling. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

Step 1: Please select on the ***Data Inputs*** tab and click on the ***Reset Form*** button. This will clear many of the input cells and reset others to default values.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SCR is for new construction or retofit of an existing boiler. If the SCR will be installed on an existing boiler, enter a retrofit factor between 0.8 and 1.5. Use 1 for retrofits with an average level of difficulty. For the more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you select fuel oil or natural gas, the HHV and NPHR fields will be prepopulated with default values. If you select coal, then you must complete the coal input box by first selecting the type of coal burned from the drop down menu. The weight percent sulfur content, HHV, and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided. Method 1 is pre-selected as the default method for calculating the catalyst replacement cost. For coal-fired units, you choose either method 1 or method 2 for calculating the catalyst replacement cost by selecting appropriate radio button.

Step 4: Complete all of the cells highlighted in yellow. If you do not know the catalyst volume ($Vol_{catalyst}$) or flue gas flow rate ($Q_{flue\ gas}$), please enter "UNK" and these values will be calculated for you. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.005 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the ***SCR Design Parameters*** tab to see the calculated design parameters and the ***Cost Estimate*** tab to view the calculated cost data for the installation and operation of the SCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Coal

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.5

* NOTE: You must document why a retrofit factor of 1.5 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	233 MMBtu/hour
What is the higher heating value (HHV) of the fuel?	7,600 Btu/lb
What is the estimated actual annual fuel consumption?	100,000,000 lbs/year
Enter the net plant heat input rate (NPHR)	10 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation: 450 Feet above sea level

Provide the following information for coal-fired boilers:

Type of coal burned: Sub-Bituminous

Enter the sulfur content (%S) = 0.26 percent by weight

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	2.35	11,814
Sub-Bituminous	0	0.13	7,600
Lignite	0	0.91	6,534

Please click the calculate button to calculate weighted values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ● Method 1
- ○ Method 2
- ○ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	219 days
Number of days the boiler operates (t_{plant})	219 days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.46 lb/MMBtu
NOx Removal Efficiency (EF) provided by vendor	50 percent
Stoichiometric Ratio Factor (SRF)	0.525

*The SRF value of 0.525 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1
Number of catalyst layers (R_{layer})	3
Number of empty catalyst layers (R_{empty})	1
Ammonia Slip (Slip) provided by vendor	10 ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	240000 acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000 hours
Estimated SCR equipment life	10 Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	300 °F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	516 ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	50 percent*
Density of reagent as stored (ρ_{stored})	71 lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	30 days

*The reagent concentration of 50% and density of 71 lbs/cft are default values for urea reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:	
50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3
19% aqueous NH_3	58 lbs/ft^3

Select the reagent used: Urea

Enter the cost data for the proposed SCR:

Desired dollar-year	2016	
CEPCI for 2016	536.4 Enter the CEPCI value for 2016	584.6 2012 CEPCI
Annual Interest Rate (i)	7 Percent	
Reagent ($Cost_{reag}$)	1.62 $/gallon for a 50 percent solution of urea	
Electricity ($Cost_{elect}$)	0.2671 $/kWh	
Catalyst cost ($CC_{replace}$)	160.00 $/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst*	* $160/cf is a default value for the catalyst cost. User should enter actual value, if known.
Operator Labor Rate	60.00 $/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00 hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

CEPCI = Chemical Engineering Plant Cost Index

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	1.62	Based on the average of vendor quotes from 2011 - 2013.	
Electricity Cost ($/kWh)	0.071	Average annual electricity cost for utilities is based on 2014 electricity production cost data for fossil-fuel plants compiled by the U.S. Energy Information (EIA). Available at http://www.eia.gov/tools/faqs/faq.cfm?id=19&t=3.	0.2671 per Ashish Agrawal, 4/21/17
Percent sulfur content for Coal (% weight)	0.31	Average sulfur content based on U.S. coal data for 2014 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	Coal data sheet at http://www.usibelli.com/Coal_data.php lists sulfur content at 0.12-0.28 percent; 2016 average was 0.13
Higher Heating Value (HHV) (Btu/lb)	8,730	2014 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	7572 from CHPP 2016 average
Catalyst Cost ($/cubic foot)	160	Cichanowicz, J.E. "Current Capital Cost and Cost-Effectiveness of Power Plant Emissions Control Technologies", July 2013.	

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	233	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	268,563,158	lbs/year
Actual Annual fuel consumption (Mactual) =		100,000,000	lbs/year
Heat Rate Factor (HRF) =	NPHR/10 =	1.00	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.37	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	3262	hours
NOx Removal Efficiency (EF) =	(NOxin- NOxout)/NOxin =	50.0	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	54.16	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	88.33	tons/year
NOx removal factor (NRF) =	EF/80	0.63	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr}	240,000	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$	110.38	/hour
Residence Time	1/V_{space}	0.01	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05	
SO_2 Emission rate =	(%S/100)x(64/32)*1E6)/HHV =	< 3	lbs/MMBtu
Elevation Factor (ELEVF) =	14.7 psia/P =		
Atmospheric pressure at sea level (P) =	2116x[(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.5	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.50	

Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.174	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x Noxadj x Sadj x (Tadj/Nscr)	2,174.33	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	250	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	288	ft^2
Reactor length and width dimentions for a square reactor =	$(A_{SCR})^{0.5}$	17.0	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	53	feet

Reagent Data:

Type of reagent used	Urea	Molecular Weight of Reagent (MW) =	60.06 g/mole
		Density =	71 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SFR x MW_R)/MW_{NOx} =	37	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	74	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	8	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	5,631	gallons (storage needed to store a 30 day reagent supply)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.1424

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	133.25	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SCR_{cost} + RPC + APHC + BPC)$$

Capital costs for the SCR (SCR_{cost}) =	\$6,408,001	in 2016 dollars
Reagent Preparation Cost (RPC) =	\$1,829,497	in 2016 dollars
Air Pre-Heater Costs (APHC)* =	\$0	in 2016 dollars
Balance of Plant Costs (BPC) =	\$2,424,756	in 2016 dollars
Total Capital Investment (TCI) =	\$13,860,931	in 2016 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 3lb/MMBtu of sulfur dioxide.

SCR Capital Costs (SCR_{cost})

For Coal-Fired Utility Boilers >25 MW:

$$SCR_{cost} = 270{,}000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$SCR_{cost} = 270{,}000 \times (NRF)^{0.2} \times (0.1 \times Q_B \times CoalF)^{0.92} \times ELEVF \times RF$$

SCR Capital Costs (SCR_{cost}) =	\$6,408,001 in 2016 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

$$RPC = 490{,}000 \times (NOx_{in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$RPC = 490{,}000 \times (NOx_{in} \times Q_B \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) =	\$1,829,497 in 2016 dollars

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

$$APHC = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$APHC = 69{,}000 \times (0.1 \times Q_B \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	\$0 in 2016 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BPC)

For Coal-Fired Utility Boilers >25MW:

$$BPC = 460{,}000 \times (B_{MW} \times HRFx\ CoalF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$BPC = 460{,}000 \times (0.1 \times Q_B \times CoalF)^{0.42}\ ELEVF \times RF$$

Balance of Plant Costs (BOP_{cost}) =	\$2,424,756 in 2016 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	\$246,884 in 2016 dollars
Indirect Annual Costs (IDAC) =	\$1,975,893 in 2016 dollars
Total annual costs (TAC) = DAC + IDAC	\$2,222,777 in 2016 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	\$69,305 in 2016 dollars
Annual Reagent Cost =	$q_{sol} \times Cost_{reag} \times t_{op}$ =	\$41,326 in 2016 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	\$116,088 in 2016 dollars
Annual Catalyst Replacement Cost =		\$20,165 in 2016 dollars
For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost		
Method 1 (for all fuel types):	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	* Calculation Method 1 selected.
Method 2 (for coal-fired industrial boilers):	$(Q_B/NPHR) \times 0.4 \times (CoalF)^{2.9} \times (NRF)^{0.71} \times (CC_{replace}) \times 35.3$	
Direct Annual Cost =		\$246,884 in 2016 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	\$2,408 in 2016 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	\$1,973,485 in 2016 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	\$1,975,893 in 2016 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	\$2,222,777 per year in 2016 dollars
NOx Removed =	88 tons/year
Cost Effectiveness =	\$25,166 per ton of NOx removed in 2016 dollars

APPENDIX I

USIBELLI COAL DATA SHEET

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Coal: Data Sheet

HEALY COAL - DATA SHEET

Producer:	Usibelli Coal Mine, Inc.
Location:	Healy, Alaska USA
Railroad:	Alaska Railroad, state owned and operated.
Shipping Port:	Seward Coal Terminal, owned by the Alaska Railroad Corporation
Coal Property:	Approximately 35,100 acres (14,200 hectares) under coal lease primarily from State of Alaska.
Reserves:	Total proven surface reserves approximately 450 million tons.
Coal Rank:	Subbituminous C
Coal Seams:	Mining is primarily from seams 3, 4, and 6 of the Suntrana Formation. These seams average approximately 18' (5.5m), 30' (9.1m), and 24' (7.3m) respectively.
Preparation:	Raw coal is crushed to 2" x 0" (50 mm x 0 mm) but no washing is performed. Screening circuit can reduce minus 1/4" (6 mm) to less than 10% with top size to 6" (150 mm).
Production:	The current production level is approximately 1.2 to 2 million tons (1 to 1.8 million Metric tons) per year.

HEALY COAL - DATA SHEET - Typical As-Mined Analysis

Proximate analysis:		
	Typical Gross As Received:	GAR Range
Moisture	29 %	27 - 32%
Ash	7 %	4 - 12%
Volatile matter	36 %	32 - 39%
Fixed carbon	26.5 %	25 - 33%
Sulfur	0.20 %	0.08 - 0.28%
Heat Value (Btu/lb)	7,560 (4,200 kcal/kg)	7,200 - 8,000 (4000-4300 kcal/kg)
Initial Deformation Temp. (Red)	2,150 degrees F (1,175 degrees C)	2050 - 2250 F (1120 - 1230 C)
T250 Temperature	2,320 degrees F (1,275 degrees C)	
Grindability (HGI)	42	

Ultimate Analysis (MAF):	
Carbon	70.0 %
Oxygen	24.0
Hydrogen	5.0
Nitrogen	0.8 (0.60 - 0.95)
Sulfur	0.3 (0.2 - 0.4)
Total	100.0 %

Typical Ash Analysis:		
Silicon Dioxide	SiO_2	44.4%
Aluminum Oxide	Al_2O_3	18.0
Titanium Dioxide	TiO_2	0.8
Iron Oxide	Fe_2O_3	7.0

Calcium Oxide	CaO	19.1
Magnesium Oxide	MgO	3.1
Potassium Oxide	K2O	1.2
Sodium Oxide	Na2O	0.3
Sulphur Trioxide	SO3	5.1
Phosphous Pentoxide	P2O5	0.07
Strontium Oxide	SrO	0.20
Barium Oxide	BaO	0.57
Manganese Oxide	MnO2	0.16
	Total	100.0 %

MINE OFFICE
PO Box 1000
Healy, AK 99743
Tel: (907) 683-2226
Fax: (907) 683-2253

FAIRBANKS OFFICE
100 Cushman St., Ste. 210
Fairbanks, AK 99701-4674
Tel: (907) 452-2625
Fax: (907) 451-6543

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APPENDIX J

AMERIAIR QUOTE FOR FGD

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Post Office Box 2705 • Woodstock, GA 30188
Phone: 678-366-0388 • Fax: 678-807-2979 • www.amerair.net

June 5, 2017

Guernsey
5555 North Grand Boulevard
Oklahoma City, OK 73112-5507

Attention: Mr. Brian A. Marshall, PE

Reference: DSI Request for Budget Information
Fort Wainwright, Alaska
Amerair Budget Proposal 170602

Mr. Marshall;

Per your request for quote for the above referenced project, Amerair Industries is pleased to submit our budget proposal for your consideration. The proposal is based on requirements submitted by e-mail as reflected in Section 1 of the proposal.

We have provided pricing and description of the SBC/Trona Injection system that is specified to meet the acid gas removal requirements. Amerair personnel offer over 30 years of dry sorbent injection experience with; Trona, and Sodium Bicarbonate. We also are experienced in the design of SBC/Trona handling and conveying systems accounting for both moisture issues as well as temperature issues that can lead to reduced activity of the reagent.

While all of these measures have been specified, Amerair typically offers these features in our standard systems. Thus, we have provided an offer in compliance with the requirements with the value added from our experience in selection of the highest performing component vendors for this application.

We trust that our package meets with your approval. If you have any questions or require additional information or explanations, please do not hesitate to contact our offices.

Sincerely,

Amerair Industries, LLC

John T. Foster
Executive Vice President Sales/Technology
cc: M. Raftis , Amerair Industries LLC

* TABLE OF CONTENTS *

SECTION 1 - DESIGN CRITERIA

Specified Operating Conditions

1.	Application:	6 x Coal Fired Boilers
2.	Fuel	Coal
3.	SO2	294 lb./hr./boiler

Environmental Design Criteria

Jobsite Location	Fort Wainwright, Alaska
Grade elevation	later
Access Engineering Code:	Per OSHA
Wind Loads	90 mph (3 sec. gust @ 33 ft.)
Seismic Loads	D
Snow Load	60 psf
Dust Density	55 pcf (volumetric); 120 pcf (structural) basis
Live Loads:	120 psf (platforms); 120 psf (landings);

SECTION 2 - SCOPE OF WORK

A. Scope Furnished by Amerair

DSI System

- SBC/Trona Silo and Silo Auxiliary Equipment w/Reagent Transfer
- Air Separator Mills w/dedicated building
- Air Separator Fabric Filter, Ductwork, I.D. Fan, Transfer Screw
- Conveying Equipment Building w/transfer hopper, feed and all conveying equipment
- SBC/Trona distribution manifolds, lances
- **CFD study for final Lance design/positioning**

- All piping and couplings within and between buildings
- One (1) Lot Controls and Field instrumentation, and engineering
- One (1) Lot Electrical Equipment and devices, and engineering
- Operation and maintenance manuals electronic copies
- Field Services and per diem rates

B. Scope Furnished by Others

- Compressed Air 65-90 psig (clean and dry to -40 degrees F) supplied to battery limits
- All reagents
- Conveying piping from injection systems to injection distribution manifolds
- Duct Flanges and access at injection locations
- Compressed Air piping to supplied equipment in Silos
- Fabric Filters
- Ductwork, I.D. Fan
- DCS (logic by Amerair)
- Emission Monitoring Equipment
- Foundations and anchor bolts for supplied equipment
- Installation of injection ports and flanges per Amerair requirements and supply
- Supply of 480 V power, 120 V power and MCC
- All wiring outside of Skids Disconnects and Silo lighting and environmental facilities
- All Electrical Engineering outside of battery limits and beyond P&ID's
- Field performance and acceptance tests
- Environmental permitting
- All Taxes, including but not limited to State, Federal, franchise, and sales and use
- Any other services not specifically included in the proposal

SECTION 3 – SYSTEM DESCRIPTION

DSI SYSTEM

SBC/Trona Silo

A. Silo Construction (Side wall height extended by 6'-6" vs. dimensions below for 230 ton capacity)

- 1 – Shop welded carbon steel industrial storage tank
- 13.5' Nominal inside diameter
- 79.00' Nominal eave height
- 54.49' Approx. straight wall storage height

Tank will have:

- 60 Degree hopper slope terminating with a 8" diameter flanged outlet
- Full skirt support with hopper outlet elevated 13.15' from base of skirt support
- 10 Degree sloped deck
- Level full capacity of 8,357 cubic feet
- Estimated working capacity of 8,057 cubic feet based on 25 degree angle of repose
- Seismic zone per IBC 2009 – Site Class D, I = 1 (Ss=48.8%; S1=16.4%)
- 90 MPH wind conditions per IBC – Exp. C, I = 1
- Loads imposed by mass flow pattern
- Design pressure & vacuum is 14 oz. positive, 1 oz. negative
- Center fill/center discharge
- 20 PSF Deck live load
- Storage of free flowing sodium bicarbonate
- Product weight of 50 PCF volume, 70 PCF for design
- Ambient operating temperature

Interior coating:	Mill Finish	
Interior skirt coating:	Polyamide epoxy	2.0 mils min. DFT
Exterior coating:	Tri-Coat System	14.5 mils min. DFT
	Inorganic zinc (3 mils min. DFT)	
	Devran 223 Epoxy (5 mils min. DFT)	
	Devthane 349QC (6.5 mils min. DFT) – per color selection	

Note: All coatings are applied over an SP10 near-white surface profile.

- Interior weld profile: Smooth, not flush
- Cylinder: Full penetration double butt welds on all vertical and circumferential welds
- Skirt (if applicable): Full penetration double butt welds on all vertical and circumferential welds
- Hopper sheet seam welds: Full penetration double butt welds
- Hopper outlet cone (if applicable): lap joint, double fillet weld
- Deck to Cylinder: Double fillet weld
- Hopper to cylinder: PJP single bevel weld
- Accessories and nozzles: Double fillet weld

B. **Accessories**

- Touch-up coating for interior/exterior
- Anchor bolts & nuts
- 1 – 3' x 6'8" White HEAVY-DUTY industrial walk-in door in skirt at platform elev.
- 1 – 6' x 6'-8" White HEAVY-DUTY industrial walk-in double door assembly in skirt (above base girder – not flush)
- 1 - 20" Diameter center roof dome with cover plate
- 1 – 24" Diameter combination manway pressure/vacuum relief valve (2 oz. pressure, 0.5 oz. vacuum)
- 1 - 36" Sq. flange for bin vent filter – 1400# max. load (Wind bracing members are not included)
- 1 – Complete 4" Diameter Sch. 40 carbon steel fill line assembly, with brackets (HDG), two (2) std. sweep elbows, 4-Bolt couplers and quickie line adapter connection with dust cap (TC std. dimensions and construction) (ships loose)
- 1 – Truck fill bracket
- 3 – 1 1/2" Diameter 3000# NPT half coupling for level indication
- 1 – 4" Dia. stub nozzle for fill in center dome
- 1 – 6" Diameter Flange on deck for level indication – designed for 250# max. dead load
- 2 – 24" Sq. reinforced opening in skirt for equipment penetration
- 1 – Full Diameter smooth bar grating platform at 8' elevation in skirt – (ships loose)
- Deck perimeter guardrail – OSHA – HDG (TC std. construction)
- Bolted outside ladder from grade to eave– HDG – OSHA – complete with safety chain (TC std. construction) (ships loose)
- 1 ONLY – Bolted straight stairway, 30" blistered treads, interior and exterior rails, complete with (1) large step-off platforms from grade to door at 8' elevation - OSHA – HDG (TC std. construction) (Ships loose)

C. **Fill Line (Field Installed)**

- Silo fill line assembly
- 4” Schedule 40 carbon steel pipe
- One target box with clean-out port
- One 90° long radius elbow
- Compression type couplings
- One malleable iron truck fill adapter with dust cap
- One NEMA 4 limit switch

Shipped loose

D. Truck Unloading Panel (Field Installed, Wired)

- Truck unloading operator station
- NEMA 4X 304 stainless steel enclosure
- Indicating lights
- Selector switches
- Alarm siren
- Push button
- Terminal blocks

Shipped loose for field install by others

E. Silo Level Indicators (Quantity of 3) (Field Installed, Wired)

- Rotating paddle type
- Stainless steel paddle
- NEMA 4 polyester-coated aluminum housing and cover
- One single-pole, double-throw switch
- 120 volt, 1 phase, 60 hertz, low torque slow speed synchronous motor

Shipped loose

F. Bin Vent (Field mounted, piped, wired to prevent damage in shipping)

- Pulse jet type
- Carbon steel housing
- 311 square feet of pleated polyester w/PTFE filter cloth
- Solenoid valves
- Pressure differential indicator and switch

- Sequence timer
- High efficiency backward curved radial fan with 3 HP, 230/460/3/60 PREMIUM efficiency induction motor
  Shipped loose

G. **Bin Vent Air Line Assembly**

- One manually operated brass isolation ball valve
- One combination filter/regulator
- One pressure gauge
- Lot of ¾" galvanized steel pipe

H. Hopper Aeration (Solimar or Approved Equal w/local control)

- Total 16 units
- 240 gallon air receiver
- Required solenoid valves
- Pipe and pipe header
- **Field installed – Field wired to controller, by Erection Contractor**

I. Silo Discharge Knife Gate Valve

- 8" diameter
- Cast SS body
- SS 304 stainless steel gate
- SS 304 stainless steel metal seat
- Teflon packing
- Electrically actuated
- Emergency hand wheel
- **Field installed**

J. Rotary Air Lock Feeder
- 8" diameter
- 1,000 lb./hr. design feed rate
- Cast iron body
- 8 vane rotor
- Fixed blades with beveled edges
- 1 HP, TEFC motor 230-460/ 3/60
- Chain drive and guard

- **Field installed, Factory wired to disconnect**

K. Diverter Valve

- One inlet and two outlets
- Mild steel construction
- Polyurethane Rubber flap seal
- Double acting pneumatic air cylinder
- Single coil, spring return
- Two limit switches
- Vendor standard finish paint
- **Field installed and piped from Mezzanine receiver**

L. Cross Screw Conveyors to Mills (Quantity 2)

CONVEYOR COMPONENT	DESCRIPTION:
DESIGNATION	9" Diameter Screw Conveyor
CONVEYOR LENGTH	22'-1" OAL Approximate
TYPE MATERIAL HANDLED	Sodium Bicarbonate
MATERIAL DENSITY	50 PCF
CONVEYOR CAPACITY	5 TPH 200 CFH
SCREW POSITION	15 Degree Incline Approximate
SCREW RPM	40 RPM
SCREW DESCRIPTION	9S312, RH, Full Pitch, Type 1 Weld w/Bare Pipe Over Discharge
FLIGHTS	3/16" Plate Mild Steel
PIPE	2" SCH 40
TROUGH TYPE	10 Gauge Formed Flange U-Trough
TROUGH ENDS SEALS	Waste Pack Seal
TROUGH % FILL	30 %
HANGERS	(1) Style 226
HANGER BEARINGS	(1) Wood Style 226
SHAFT DIAMETER	1 1/2"
END BEARINGS	4-Bolt Flange Ball Bearing
INLET	(1) Inlet, Standard with Flange
DISCHARGE	(1) Discharge, Standard with Flange
COVERS	14 Guage Flanged, Gasketed & Bolted On 24" Centers
PAINT/CLEANING	Orthman Blue Urethane Exterior Surfaces
SPEED SENSOR	N/A
OTHER	
OTHER	
DRIVE COMPONENTS	**Class II Service Selection**
REDUCER	Dodge TA 1107H31 x 1 1/2" Screw Conveyor Drive
MOTOR	3 HP Tefc, WEG Electric W22 Series Inverter Duty
MOTOR MOUNT	Dodge TA 1107 MM
BELT GUARD	Dodge TA 1107 BG
BELT DRIVE	Included--(2) Groove Minimum

Air Classifier Mill System

M. Mill Building 18' x 18' x 20'

WALLS

STEEL FACINGS BOTH SIDES OF WALL (S/S): 72 LF @ 20' ft tall

The walls shall be 3" thick composite sandwich panels. The exterior and interior shall be 26 GA stucco-embossed steel, pre-painted white. The core shall be of 99#, 3/4" cell, 11% phenolic-resin impregnated structural Kraft honeycomb. Panel division/finish strips shall consist of color coordinated vinyl "H" connectors that shall not protrude more than 1/16" beyond the finished wall panel. The entire panel shall be laminated together using a solvent free two-part polyurethane adhesive and pressure. The panels shall have formed edge connectors that are capable of being friction locked without mechanical fasteners using a full-length joint without through metal connectors. The joint shall allow lateral expansion and contraction. This shall result in a structural panel that shall not require support columns every 4'.

GABLE CLASS A ROOF W/ 9" OVERHANG

POLYSTYRENE ROOF -3", 3-PLY: 1,019 square feet

The roof shall be 3" thick composite sandwich panels. Both sides shall be stucco-embossed aluminum pre-painted white. The core shall be of 1 lb. density polystyrene foam. The entire panel shall be laminated together using a solvent free two-part polyurethane adhesive and pressure. The panels shall have formed edge connectors that are capable of being friction locked without mechanical fasteners using a full-length joint without through metal connectors. The joint shall allow lateral expansion and contraction.

wall & roof core

Polystyrene:

The polystyrene core shall have the following mechanical properties;

Shear strength (flatwise)	18 -22 PSI
Shear Modulus (flatwise)	280 - 320 PSI

The water absorption rate shall be less than 4%

INSULATION

All wall and roof panels shall be insulated to a minimum R value of 11.

NO CEILING

DOORS

20 GAUGE insulated STEEL double doors WITH 1/2 GLASS: 1 Each

The door(s) shall be **72"w X 84"h X 1 3/4"** thick and shall be constructed of 20 gauges hot dipped galvanized steel, mill treated for proper paint adherence. The door shall have top and bottom channel of 16 gauge steel projection welded to door skins on no less than 2" centers. The top channel is to be flush while the bottom channel is to be inverted. The hinge preparations are to be 9-gauge steel reinforcement's projection welded to the door skins in six places each. Hinge preparation is to be cut through the doors and provided with reversible filler plates to allow building site handling. Standard hinge preparation is to be 4-1/2" regular weight .134" hinge, conforming to ANSI A1567, three preparations. The doorframe shall be 16-gauge single "rabbit" commercial quality steel. The frame shall be pre-mortised for application of matching hinges and striker set of the door. The door shall be supplied with all necessary hardware as to meet local and state code requirements. The door shall be fabricated as to include 1//8" tempered safety glass in the upper half. The windows shall measure approximately 22"w X 36"h.

NO WINDOWS

ELECTRICAL

ELECTRICAL PACKAGE - CONCEALED: 1 EACH

The electrical package shall consist of 1/2" EMT cable concealed in the panel and attached to flush mounted 2x4 boxes at receptacle and switch locations. There shall be **(1**) wall switch, **(9)** duplex receptacles, **(0**) 3 way wall switch, **(0)** telephone/computer prep, **(5)** fluorescent fixtures (100 foot candles at desk height). This package shall meet NEC (current edition). Wiring is not included.

125 AMP SINGLE PHASE 14 SPACE MAIN LUG BREAKER BOX: 1 EACH

The electrical service shall include an indoor load center of sufficient amperage and circuit capacity as to handle all lighting loads, receptacles and HVAC systems. NOTE: The entire electrical system for the modular building shall be in accordance with the National Electrical Code and shall meet all N.E.C requirements

Climate Control

AIR CONDITIONING - COOLING & HEATING: 1 EACH

The air conditioner shall be 18,000 BTU's of cooling and 11,100 BTU's of heating. The unit shall be a through-the-wall type with panel preparation included. The unit shall be 230/208V, 60HZ, 20 AMP

NO FLOORS

N. Air Classifier Mills (Quantity 2)

<u>General Process Specifications:</u>

1.	Process Material:	Sodium BiCarbonate		
2.	Material Characteristics:	Feed Bulk Density:	TBD	
		Inlet Feed Size:	50 – 100 microns	
3.	Milled Product Size	D90 = 15 microns		
4.	Capacity:	> 5,000 lb/hr		

<u>General Equipment Specifications</u>

1.	Materials of Construction	Carbon steel		
2.	Paint System	Manufacturer's standard		
3.	System Design	Pressureless construction		
4.	Electrical Utility	Main:	480 V / 3 Phase / 60 Hz	
5.	Controls & Instruments (Located in process area)	Controls:	110V/1PH/60Hz	
		Instrumentation:	Analog:	4-20ma DC
			Digital:	120 VAC
6.	Area Classification	Non-Hazardous		

Equipment Specifications

Item 1 – Mikro-ACM® Model 300 Air Classifying Mill:

Mikro-ACM® Model 300

- Material of Construction: Cast iron / carbon steel
- Gravity-drop feed assembly consisting of a fabricated inlet funnel with inclined feed chute bolted to mill inlet flange.
- Rotor assembly: eight (8) bar hammers with Tungsten Carbide tipping
- 24 Long canted blade classifier
- Ni-Hard MD liner
- Standard baffle / shroud assembly
- Grinding chamber with inspection door and limit switch
- Structural steel base with stand legs and integral main drive belt guard.
- Automatic lubrication system.
- Constant speed 300 HP main drive motor, multi V-belt arrangement, 1800 RPM, 460 V / 3 HP / 60 Hz TEFC
- Direct connected 50 HP, 460 Volt, 3 Phase, 60 Hz, Inverter Duty 4:1 TEFC classifier motor with coupling and guard.
- Speed Pick-up Assembly for classifier wheel.
- One coat of primer and one coat of finish enamel on mild steel surfaces– HMPS standard.

Item 2 – Rotary Airlock – Mikro-ACM 300 Feeder

- Type: Drop-thru type
- Size: 10" ID Square Inlet and Outlet Flanges
- Material of Construction: Carbon steel
- Rotor: 8-vane rotor
- Beveled edges on rotor vane tips
- Chain drive
- 1.0 HP, variable speed motor, 460/3/60
- Enclosed drive guard, base & mounting
- Two (2) flange gaskets

Common to the Two Mills

Item 3 - System Blower

- Rated for 20,000 ACFM, -65" WC, 125° F
- Based on estimated site elevation of 40 ft ASL
- Flanged Inlet & Outlet
- Coupling & Shaft Guards
- Housing Drain
- Discharge Silencer
- 300 HP Inverter Duty Motor (VFD by customer)

Item 4 - Control Panel & Instrumentation

- NEMA 4 enclosure
- Allen-Bradley Compact Logix PLC
- Pushbutton style panel, with lighted pushbuttons and lamps for system motors, etc.
- Auto Mode for sequential start/stop of all equipment.
- Maintenance Mode for individual motor start/stop (Note: there are no motor running permissive in this mode.)
- Motor starters and variable frequency drives not included – to be supplied by customer and installed in customer's Motor Control Center
- One (1) Thermal Mass Flow Meter – System Airflow
- Speed transmitter for classifier speed, with digital speed display on panel
- Differential Pressure Gauge - ACM 300 Mill
- Differential Pressure Switch – Product Collector Filters
- Level Probe – Product Collector

O. Air Separator Filter and Conveyor System Transfer [Common]

1. Equipment Selection

Quantity of Baghouses	One (1)
Baghouse Model	(1) WIP-26/25 210 D5 (15 x 14v)
Number of compartments per baghouse	1
Bags per baghouse	210
Cloth area per bag, sqft (effective)	35.434
Total cloth area, all compartments, sqft	7,441
Gross filter ratio, single compartment (@20,000 ACFM)	2.54

2. Construction

Main Housings and Clean-air Plenums	3/16" C.S.
Tubesheets	3/16" C.S.
Hoppers	3/16" C.S.

- Inlet & Outlet Manifolds 3/16” C.S.

3. Clean Air Plenum

- Type Walk-in Plenum
- Height 13’-6”
- Access Galvanized grating walkway along baghouse
- Access Caged Ladder w/rest platform

4. Hoppers

- Configuration Pyramid
- Slope angles°: valley / end / side 55 / 64.6 / 62.8
- Discharge 12” x 12 ft. flanged
- Discharge height (from grade) 20’-0”
- Hopper volume (effective) 281 cu. ft.
- Accessories (per hopper):
  - Access Door (24” x 24”) One (1)
  - Poke Holes (4” dia.) Two (2)
  - Strike Anvils Two (2)
  - Level switch One (1)
  - Hopper vibrators (electric) Two (2)
  - Screw Conveyor 9” x 26’(approx..) One (1)
  - Rotary Air Lock 8” One (1)

5. Filter Assemblies

- Bags
  - Quantity per baghouse 210
  - Diameter x length 5” dia. x 26’-3” long
  - Attachment Stainless steel snap ring
  - Material Polyester Felt
  - Weight (nominal) 16 ounce
  - Finish (Base) Singed

- Cages
  - Quantity per baghouse 210
  - Type Two-piece Cage
  - Wires 11 gauge, 20 vertical wires
  - Spacing 8” girth ring spacing
  - Material C.S.

6. Pulse Cleaning System

- Cleaning Manifold — 12” diameter
- Blowpipe — 3.5” dia. 1/8” wall tubing w/1-1/2” nozzles
- Diaphragm Valves — 3” diaphragm
- Header Valves — Isolation valve and drain valve

7. Access

Main platform (1)	Full Section 3’ wide Along Plenum Row
Grating	4" x 1-1/4" x 3/16"
Handrail	Two rail handrail, 1-1/4 " nominal pipe
Toeplates	4" x 1/4"
Caged Ladder (1)	From Grade to Walk In Plenum Platform

8. Surface Preparation and Painting

Exterior Fabricated Steel Surfaces

- Plate Steel (baghouse compartments, stubs)
  - Surface Preparation — SP-3
  - Paint — Macropoxy compatible
  - Finish Paint — SW Macropoxy 646 4-5 mils dft
- Cold steel (support stubs, access steel, etc)
  - Surface Preparation — SSPC-SP-3
  - Primer / Finish Paint — SW Macropoxy 646, 4-5 mils dft
- Vendor Supplied Equipment
  - Provided with Vendor’s standard paint system.

9. Controls and Instrumentation

Control System Hardware

- Pulse Cleaning Enclosures: — One (1) NEMA 4x enclosure per baghouse

Pulse Jet Cleaning Control System

- The cleaning system is fully automatic and will be initiated by overall baghouse differential pressure with a timed sequence override.
- Timer/sequencer cards provide the cleaning cycle control.

Field Instrumentation (per baghouse)

- One (1) Baghouse Differential Pressure Photohelic
- One (1) Baghouse Pulse Timer panel
- One (1) Pulse Header Pressure Gauge
- One (1) Baghouse Compartment Differential Pressure Gauge
- One (1) baghouse hopper level switch (capacitance type)

Electrical

- Screw conveyor motor 2.0 H.P. 460V/3Ph/60Hz
- Rotary Air Lock Motor 1.0 H.P. 460V/3Ph/60Hz

10. Ductwork

- Mill Pair to Fabric Filter Inlet – 24” diameter Y branch with 24” manual butterfly damper in each branch, straight riser section to fabric filter inlet, two elbows
- Fabric Filter Outlet to I.D. Fan – 32” diameter with one elbow and one transition to I.D. Fan inlet box, vibration joint.
- I.D. fan outlet stub w/silencer
- Finishing of all in accordance with 8. Above

P. Conveying Equipment Building

WALLS

STEEL FACINGS BOTH SIDES OF WALL (S/S): 128 LF @ 20‘ ft tall

The walls shall be 3" thick composite sandwich panels. The exterior and interior shall be 26 GA stucco-embossed steel, pre-painted white. The core shall be of 99#, 3/4" cell, 11% phenolic-resin impregnated structural Kraft honeycomb. Panel division/finish strips shall consist of color coordinated vinyl "H" connectors that shall not protrude more than 1/16" beyond the finished wall panel. The entire panel shall be laminated together using a solvent free two-part polyurethane adhesive and pressure. The panels shall have formed edge connectors that are capable of being friction locked without mechanical fasteners using a full-length joint without through metal connectors. The joint shall allow lateral expansion and contraction. This shall result in a structural panel that shall not require support columns every 4'.

GABLE CLASS A ROOF W/ 9” OVERHANG

POLYSTYRENE ROOF -3", 3-PLY: 1,019 square feet

The roof shall be 3" thick composite sandwich panels. Both sides shall be stucco-embossed aluminum pre-painted white. The core shall be of 1 lb. density polystyrene foam. The entire panel shall be laminated together using a solvent free two-part polyurethane adhesive and pressure. The panels shall have formed edge connectors that are capable of being friction locked without mechanical fasteners using a full-length joint without through metal connectors. The joint shall allow lateral expansion and contraction.

wall & roof core

Polystyrene:

The polystyrene core shall have the following mechanical properties;

Shear strength (flatwise)	18 -22 PSI
Shear Modulus (flatwise)	280 - 320 PSI

The water absorption rate shall be less than 4%

INSULATION

All wall and roof panels shall be insulated to a minimum R value of 11.

NO CEILING

DOORS

20 GAUGE insulated STEEL double doors WITH 1/2 GLASS: 2 Each

The door(s) shall be **72"w X 84"h X 1 3/4"** thick and shall be constructed of 20 gauges hot dipped galvanized steel, mill treated for proper paint adherence. The door shall have top and bottom channel of 16 gauge steel projection welded to door skins on no less than 2" centers. The top channel is to be flush while the bottom channel is to be inverted. The hinge preparations are to be 9-gauge steel reinforcement's projection welded to the door skins in six places each. Hinge preparation is to be cut through the doors and provided with reversible filler plates to allow building site handling. Standard hinge preparation is to be 4-1/2" regular weight .134" hinge, conforming to ANSI A1567, three preparations. The doorframe shall be 16-gauge single "rabbit" commercial quality steel. The frame shall be pre-mortised for application of matching hinges and striker set of the door. The door shall be supplied with all necessary hardware as to meet local and state code requirements. The door shall be fabricated as to include 1//8" tempered safety glass in the upper half. The windows shall measure approximately 22"w X 36"h.

NO WINDOWS

ELECTRICAL

ELECTRICAL PACKAGE - CONCEALED: 1 EACH

The electrical package shall consist of 1/2" EMT cable concealed in the panel and attached to flush mounted 2x4 boxes at receptacle and switch locations. There shall be **(0**) wall switch, **(13)** duplex receptacles, **(2**) 3 way wall switch, **(0)** telephone/computer prep, **(14)** fluorescent fixtures (100 foot candles at desk height). This package shall meet NEC (current edition). Wiring is not included.

125 AMP SINGLE PHASE 14 SPACE MAIN LUG BREAKER BOX: 1 EACH

The electrical service shall include an indoor load center of sufficient amperage and circuit capacity as to handle all lighting loads, receptacles and HVAC systems. NOTE: The entire electrical system for the modular building shall be in accordance with the National Electrical Code and shall meet all N.E.C requirements

Climate Control

AIR CONDITIONING - COOLING & HEATING: 2 EACH

The air conditioner shall be 18,000 BTU's of cooling and 11,100 BTU's of heating. The unit shall be a through-the-wall type with panel preparation included. The unit shall be 230/208V, 60HZ, 20 AMP

NO FLOORS

Internal Mezzanine Level for Storage Hopper and Feeders

MEZZANINE

MEZZANINE STRUCTURE AND LOAD RATING: 125 PSF – L / 360

The mezzanine floor support and loading shall consist of 5" x 5” x 3/16” square columns with 5/8" thick X 12" square plates as bases. Column loading represents the maximum weight placed on the existing floor if the mezzanine is loaded to its maximum capacity on each square foot. The end user should verify that their floor has adequate strength to support the column loading. The perimeter and intermediate support beams shall be structural beams. Joists shall consist of properly sized bar joists.

1” Bar grating Floor Decking: 880 square feet

Decking shall be composed of 1” thick 19w4 welded bar grating. The material shall be painted shop coat black. Bar grating shall be attached with saddle clamps and tek screws.

IBC STAIR SYSTEM: 1 EACH

Application – The stairs listed below meet the standards for FACTORY and STORAGE USE GROUPS with occupancies of 50 or less people.

Treads shall be 42” wide with closed risers. Tread rise shall be a maximum of 7” and tread run shall be a minimum of 11”. Tread and closed riser material is to be steel diamond plate. Stair railing shall be constructed of 2” x 2” angle uprights and 1-1/2” horizontal tubes. Stair railings shall be 36” tall and shall be spaced so as to allow a sphere no larger than 21” diameter to pass through any opening.

Landings shall be sized appropriately so as to meet code requirements. The landing floor is to be constructed of steel diamond plate. Landing railing shall be constructed of 2” x 2” angle uprights and horizontal 1-1/2” tubes. Landing railings shall be 42” tall and shall be spaced so as to allow a sphere no larger than 21” diameter to pass through any opening. All landing railing shall include a 4” tall toe plate.

Application – The stairs listed below meet the standards for the BUSINESS USE GROUPS with occupancies of 50 or less people.

Treads shall be 36” wide with closed risers. Tread rise shall be a maximum of 7” and tread run shall be a minimum of 11”. Tread and closed riser material is to be steel diamond plate. Stair railing shall be constructed of 1-1/2” tube. Stair railings shall include 36” tall handrails with an exterior guardrail whose overall height is 42”. The handrails are to be constructed so as to allow a sphere no larger than 4” diameter to pass through any opening.

Landings shall be sized appropriately so as to meet code requirements. The landing floor is to be constructed of steel diamond plate. Landing railing shall be constructed of 1-1/2” tube. Landing railings shall be 42” tall and are to be constructed so as to allow a sphere no larger than 4” diameter to pass through any opening. All landing railing shall include a 4” tall toe plate.
FOR OCCUPANCIES LARGER THAN 50 PEOPLE THE TREAD WITDH IS TO INCREASE TO 44” W.

FASTENERS:

All wedge anchors, bolts, nuts; washers, and screws shall be supplied with the system. No additional fasteners will be needed to complete the structure.

FINISH:
All structural beams, columns, landings, handrail and gates are powder coated our standard colors. Bar joists are primed gray and are not powder coated. Special colors and powder coating the bar joists can be coated upon request. All handrails shall be painted safety yellow.

Q. Feed Hopper (on mezzanine level of conveying equipment building)

- 4’ high 60 degree x 36’ long covered feed hopper supported at the upper building level, finished in accordance with O. 8. Above
- 2.5” pipe vent line to inlet of fabric filter
- Integral reverse flight screw conveyor in 1’ wide bottom of hopper for feed distribution
- 8” flanges for Feed and Conveying trains
- 8” manual slide gates for maintenance isolation
- 8” rotary air lock valves w/0.5 H.P. drive, drop chute to feeders

<u>Feed and Blower Trains (8 operating, 2 on-line spares) in Conveying Room</u>

R. Gravimetric Screw Feeders on Mezzanine Level (Quantity 8) – Techweigh or Equal

- Capable of feeding 25 – 250 (FF) and 50 – 500 (ESP) pounds per hour (max) of SBC/Trona with a density of 50 lb./ft^3
- 304 stainless steel trough
- 304 stainless steel discharge spout
- 2” Solid flight feed screw with material conditioning plows
- 0.5 HP, DC drive screw, 0.25 HP hopper agitator
- Variable speed VFD drive located in the system panel
- NEMA 4X local panel controller
- **Factory installed on Feeder/Hopper/Air lock Skid**

S. Vented Hopper with Cartridge Filter (Quantity 10)

- Horizon (or Approved Equal) Air Vent Hopper
- Pulse Cleaned Cartridge Filter
- 1.0 HP Vent Fan to Silo Skirt Interior
- Pre Wired to local disconnect
- **Factory Installed as part of feeder/rotary valve skids**

T. Rotary Air Locks to Feed Lines (Quantity 8)

- 8” diameter air lock
- 450 lb/hr design feed rate
- Cast iron body
- 8 vane rotor
- Fixed blades with beveled edges
- 0.5 HP, TEFC motor 230-460/ 3/60
- Chain drive and guard
- Air purge shaft seals
- Factory wired to local disconnect
- Integrated with Air Vent Hoppers

Conveyor Skids Shop Assembled

U. Inlet Air Dehumidifier (located at top of each skid), 8 total

- Dehumidifier Munters HC-300 (shop mounted on blower skid, exhaust duct to outside silo provided but installed by Erection Contractor. Dehumidifier description per below:

Technical data - System Features

Main selections	
Electrical power source	460/3/60
Dehumidifier model	HC-300
Reactivation heater type	Electric
Desiccant type	TiGel
Full load amps (FLA)	9.7 A
Part number	30569-04
Process Airstream	
Filter size	20-3/4" x 5-3/4" x 1/2"
Filter efficiency	Metal mesh
External static Pressure	1.75 in WC
React Airstream	
Filter size	7" x 6-1/2" x 1/2"
Filter efficiency	Metal mesh
External static pressure	1.25 in WC

- Inlet Duct – 4” to 6” duct for fresh air to building wall to inlet filter
- Outlet Duct – Regenerator side exhaust duct for moist gas to outside of building
- Dry Air Duct – 4” duct of dry air to blower inlet silencer

V. Blower Packages – Base of Skid Mounted (Quantity 8)

Universal Blower Pac package to provide 300 ICFM at 6 - 10 PSIG. Including:

- Westwood EMFP-3 FilterProGENTEX DRSI-3 Gr.I Silencer Internal Universal Flex Joint
- Gardner Denver 408 Heliflow Blower Internal Universal Flex Joint
- 25 HP ODP PE 1800 rpm 460/60/3 Motor V-Belt Drive
- Base & Guard
- ProGENTEX DRS-3 Gr.I SilencerKunkle 2-Inch 337 Relief ValveExternal Universal Flex Joint Flexi Hinge 3-Inch 502 Check Valve Keystone 3-Inch Butterfly Valve Winters PFQ902 Pressure Gauge
- UE J6 Pressure Switch

<u>Heat Exchanger and Vent Hopper Shipped Loose for Installation in Field</u>

W. Heat Exchangers w/rack mount (Quantity 8 exchangers)

- Xchanger, Inc. Rating for Model AA-400 ref #123439

		HOT SIDE	COLD SIDE
• PERFORMANCE		HOT SIDE	COLD SIDE
• Fluid Circulated		Air	Air
• Volumetric Flow Rate		300.0 Std. ft 3/min	1,313.1 Std. ft 3/min
• Total Fluid Entering		1,350.0 lb/hr	5,909.0 lb/hr
• Liquid			
• Vapor			
• Non-Condensibles		1,350.0 lb/hr	5,909.0 lb/hr
• Vaporized or (Cond.)			
• Temperature In		160.0 °F	85.0 °F
• Temperature Out		110.4 °F	114.5 °F
• Inlet Pressure	(Absolute)	20.372 lb/in 2	14.372 lb/in 2
• Velocity	(Standard)	1,437 ft/min	1,434 ft/min
• Pressure Loss		0.10 lb/in 2	0.05 lb/in 2
• Fouling Factor		0.0001 ft 2-°F-hr/BTU	0.0001 ft 2-°F-hr/BTU
• Total Heat Exchanged:	20,598 BTU/hr		
• CONSTRUCTION			
• Design Temperature		200 °F	Not Applicable
• Design Pressure	(Gauge)	15 lb/in 2	Not Applicable
• Test Pressure	(Gauge)	15 lb/in 2	Not Applicable
• Cyclic Pressure		No	Not Applicable
• Flow Direction		Right Hand Horizontal	Vertical Up/Pull

Through
- Plate-Fin Core : Aluminum Fan Hood : Galvanized Steel
- Fan Guard : Coated Carbon Steel Venturi Frame : Coated Carbon Steel
- Drawing Number : Weight : 165 lb
- CONNECTIONS
- Process Inlet : 3 inch pipe stub
- Process Outlet : 3 inch pipe stub
- MECHANICAL EQUIPMENT
- Fan Diameter : 12 inch Motor : 1.00 HP TEFC
- Fan Qty/Speed : 1 / 3480 RPM Motor Qty/Speed : 1 / 3480 RPM
- Fan Type : 4 Blade Mill Galv. St Motor Electrical: 208-230/460/3/60

X. Piping in Conveyor Room (8 lots)

- Blower Outlet Silencer to Heat Exchanger – 3" Fernco Vibration Coupling at Blower Silencer, 3" Sch 40 carbon steel straight run, 3" Flex Hose w/quick couplings to Heat Exchanger Intlet
- Heat Exchanger Outlet to Vent Hopper Discharge Line – 3" Marine Flex Hose w/quick couplings to inlet stub of Vent Hopper transition/pipe.
- Vent Hopper Discharge Pipe to Building Outlet Stubs – 3" Marine Flex Hose w/quick couplings to Building outlet 3" Sch 40 pipe stub w/quick coupling Female end
- Building Outlet Stubs (8) – One stub for each field injection point using 3" sch. 40 pipe w/outlet quick disconnect for connection to Owner's field run pipe to Injection Distributors

Note: The four lines going to the ESP injection distributors have one redundant Feeder/Conveyor System that can be activated and attached by moving the Vent hopper discharge hose to the appropriate building outlet stub when needed.

The four lines going to the Fabric Filter injection distributors also have one redundant Feeder/Conveyor System that can be activated and attached by moving the Vent hopper discharge hose to the appropriate building outlet stub when needed.

Y. Injection Manifolds/Lances (One/Fabric Filter)

Four (4) Amerair proprietary design injection nozzles per ESP or Fabric Filter located at ports designed by **Amerair, and supplied and installed by Owner's erection contractor**.

Nozzles feature:

- Integral dynamic mixing
- 316 SS construction 1-1/2" diameter lances
- 316 SS mating flange to port flanges
- 1' diameter x 1' cylinder height (conical bottom) four (4) port injection distributor mounted at duct w/supplied brackets
- 1-1/2" SS 316 ball valve at each distributer port for on line maintenance
- 1-1/2" braided hose connections from distributer ports to lance stubs with hardware
- **Full CFD study for optimized distribution using off set angles and lengths; One study for the ESP injection duct assuming duplicate geometry for the 4 and one study for the Fabric Filter injection duct assuming duplicate geometry for the 4.**

Z. **Consumables and Preliminary Load List**

Following Page

MOTOR/LOAD	QUANTITY	HP ea.	KW total Connected	Duty %	Total KW Consumed
PROCESS EQUIPMENT					
Bin Vent Blower DSI	1	3.0	2.24	3	0.067
Hopper Rotary Airlock	1	0.50	0.38	100	0.38
Transfer Screws	2	3.0	4.48	50	2.24
Mill Air Lock	2	1.0	1.5	50	0.75
Mill Motor	2	300	448.2	50	224.1
Mill Classifier	2	50	74.7	50	37.4
Separator FF I.D. Fan	1	300	224.1	100	224.1
Fabric Filter Transfer Screw	1	3	2.24	100	2.24
Hopper Feed Rotary Airlock	1	1	0.75	100	0.75
Hopper Distribution Screws	2	3	4.48	100	4.48
Feeder Rotary Airlocks	8	0.5	3	75	2.24
Gravimetric Feeders	8	0.5	3	75	2.24
Gravimetric Feeders	8	0.25	1.5	75	1.13
Vent Hopper Blower	8	0.5	3	75	2.24
Drop Thru Rotary	8	0.50	3	75	2.24
Desiccant Dehumidifiers	8		56	75	42
Conveying blower DSI	8	25	149.4	75	112
Conveying after cooler DSI	8	1.0	-6	75	4.5
Instrument/Control	All		15	100	15
NON PROCESS					
HVAC and Heaters	6		30	0	0
VENT Fan	2	1	1.5	0	0
Lighting	5	1.2	6	0	0

Note: Non process equipment not calculated in power consumption total

Expected SBC Consumption 2778 to 4167 ton/yr. at 50%-80% removal combined FF

Expected Compressed Air Consumption = 60 SCFM, dry -40 F, 90 PSIG

AA. **Field Service and Start Up Option Pricing**

Erection Advisor: Amerair will provide the services of an Erection Field Advisor to consult with the Owner's Erection Contractor on critical phases of the equipment installation. Amerair has allowed **15 man days (8 hrs. day)** of said services with **three separate trips** to site. Additional services if required will be provided at per diem rates.

Pre Commissioning Field Services: Amerair will provide the services of a qualified field Engineer for the purposes of equipment check out to ensure that proper installation of equipment and all electrical continuity has been achieved. This phase will also include all pre commissioning testing. Amerair has allowed **15 days at 8 hrs./day** and **one trip** for this purpose. Additional services if required will be provided at per diem rates.

Start Up Services: Amerair will provide the services of a Mechanical Field Engineer and a PLC Field Service Engineer each for a period of **7 x 8 hr. days** allowed in the base pricing. This personnel will provide services during the first week of operation and also provide on site training during that period. Additional services if required will be provided at per diem rates

Per Diem Rates:

Erection Advisor:	$ 1100/day
Pre Commissioning Field Services:	$ 1100/day
Start Up Mechanical:	$ 1100/day
Start Up Electrical/Control:	$ 1200/day

‘* Travel expenses are in addition to per diem rate and billed at cost.

SECTION 4 - PERFORMANCE, GUARANTEES, & WARRANTY

4.1 OPERATING CONDITIONS

The design/operating conditions are in accordance to the Specification and as reflected in the Design Conditions Section 1 of this proposal.

4.2 PERFORMANCE

Subject to the conditions and limitations contained herein and provided the baghouse is operated within the operating conditions as set forth in Section 4.1 above the performance shall be as stipulated below.

4.2.1 SOLID PARTICULATE MATTER (PM) EMISSIONS

Covered in Fabric Filter Proposal

4.2.2 SO_2 EMISSIONS

Final SO2 emissions will be 50% to 80% less than the combined inlet Values on Proposal Section 1 Inlet Values. Testing to be the average of three, 3 hour tests conducted according to EPA method 30B.

4.2.3 HCl EMISSIONS

N/A

4.2.4 OPACITY

N/A

Non-emissions related

4.2.5 SORBENT FEED RATE (TO FABRIC FILTER INLET)

The Sodium Bicarbonate feed rate will not exceed **2778 to 4167 tons/yr. for the combined 6 units** based on specified 15 micron D-90 milled Sodium Bicarbonate. Measurement of rate shall be by gravimetric feeder instrumentation. Turndown from guarantee feed rate is further guaranteed at a ratio of 10:1 again as measured by gravimetric feeder instrumentation. Verification shall be by timed collection of lime feed.

4.2.6 FLUE GAS PRESSURE DROP

Addition of sorbent injection lances will not result in an added pressure drop greater than 0.025" water column as measured by mutually agreed upon methods at operating conditions per Section 4.1 before and after addition of injection lances.

4.2.7 POWER CONSTUMPTION

The auxiliary power consumption including all process equipment but excluding all heating, lighting, ventilation, lifting and all convenience items with "0" demand factor per the load list Section 3 Article HH will not exceed an average of **760 KW.** Consumption is to be determined by mutually agreed MCC clamp with all non-process equipment not operating.

4.2.8 NOISE

Noise from individual devices shall not exceed **85 dBA** at a distance of 3 ft. and 5 Ft.. above grade. Where measurements exceed 85 dBA due to suspected resonances or other anomaly, shop measurements for the same equipment will prevail.

4.3 GUARANTEE PROVISIONS

The Guarantees set forth herein are subject to the following provisions:

1. The equipment shall be operated and maintained according to Seller's O&M Manual prior to testing.
2. Process operating conditions must remain as set forth in the Design Specifications
3 The customer shall cooperate with and assist Seller in making any corrections or adjustments which may be necessary in order to meet the warranty.
4. All replacement parts shall be of Seller's manufacture or supply.
5. Emission testing is to be performed by others per the above agreed upon method within 24 months after successful installation and witnessed at the option of Seller. Seller shall be given at least two (2) weeks notice prior to testing.
6. Within five (5) days before the outlet emission performance test date, the equipment shall be operated for a period of no less than seventy-two (72) continuous hours at the specified design operating conditions at constant temperature.

7. All auxiliary emission control equipment must be maintained in proper operating condition in accordance with the manufacturer's O&M manual.

4.4 EQUIPMENT REMEDY

If prior to the expiration of the Guarantee Period set forth herein, Seller received written notice from the Owner that the equipment fails to meet the above Performance Guarantee (as determined by results of the Field Performance Testing Methods stated herein), Seller agrees to provide all necessary material in accordance with the Ex-Works terms of the contract for modifications or corrections to the equipment in order to meet the Performance Guarantees.

THE PERFORMANCE GUARANTEES SET FORTH IN THIS SECTION ARE THE SOLE PERFORMANCE GUARANTEES MADE BY THE CONTRACTOR WITH RESPECT TO THE EQUIPMENT AND NO OTHER WARRANTIES OR GUARANTEES OF PERFORMANCE, WHETHER STATUTORY, WRITTEN, ORAL, EXPRESSED OR IMPLIED BY LAW SHALL APPLY. THE OWNER'S EXCLUSIVE REMEDY AND THE CONTRACTOR'S SOLE OBLIGATION FOR FAILURE TO MEET THE PERFORMANCE GUARANTEES SHALL BE THOSE STATED IN THIS SECTION.

4.5 WARRANTY

A. Seller warrants that the Equipment described herein when shipped is free from defects in materials and in Seller's workmanship and design. If any such defect exists or later appears, Seller shall undertake, at its sole expense, prompt remedial action as stated herein to correct the same, provided, however, that Seller shall have no obligation or liability under this Warranty unless it shall have received written notice specifying such defect no later than twelve (12) months from the completion of start-up or eighteen (18) months from the date of substantial shipment of the Equipment by the Seller, whichever occurs first.

B. Remedial action under this Warranty shall require only that Seller, at its option, repair or modify the part or replace the same Ex-Works shipping point.

C. On an equipment supply only contract, Owner shall be responsible for field labor and all in and out costs on warranty repairs or replacements.

D. This warranty is subject to the following conditions: (a) Seller's instructions as to handling, installation, operation and maintenance have been followed; (b) the

Equipment and associated equipment have been used under normal operating conditions; (c) the Equipment has been properly operated and maintained and has not been affected by misuse, neglect or accident; (d) Owner has not attempted or performed corrective work without Seller's prior written consent and (e) Contractor shall have received written notice of any defect no later than ten (10) days after Owner first has knowledge of same. The above Warranty does not cover, and Seller makes no warranty which extends to, damage to the Equipment due to deterioration or wear occasioned by abrasion, corrosion, or erosions.

E. THIS WARRANTY IS IN SUBSTITUTION FOR, AND IN LIEU OF, ANY AND ALL OTHER WARRANTIES, EXPRESS, IMPLIED OR STATUTORY, INCLUDING WARRANTIES OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE.

F. Remedial action in the manner and within the period of time specified above shall constitute fulfillment of all liabilities from Seller to Owner and Owner's sole remedy hereunder whether based on contract, warranty, negligence or otherwise.

Limitation of Liability

In no event shall the total liability of the Seller arising out of the performance or breach of this Purchase Order, whether based on contract, warranty, negligence, indemnity, strict liability or otherwise, exceed the Purchase Order price.

The Seller shall in no event be liable for any consequential, incidental, indirect, special, or punitive damages arising out of this Purchase Order or any breach thereof, or any defect in the Equipment purchased hereunder, including, but not limited to, lost profits or revenue, work stoppage, impairment of other goods, loss by reason of shutdown or non-operation or increased expenses of operation, whether or not such loss or damage is based on contract, warranty, negligence, indemnity, strict liability or otherwise.

Indemnity

Seller hereby releases and will indemnify, defend and hold harmless Owner from and against any and all claims, suits, demands, liability, losses, damages or expenses, including reasonable attorney's fees, of any kind or nature whatsoever, to the extent any such claims, suits, demands, liability, losses, damages or expenses, including reasonable attorney's fees are: (1) the direct result of a negligent act or omission of Seller, its subcontractors or other third parties under Seller's reasonable direction and control; and (2) are attributable to bodily injury, sickness, disease or death, or to injury to or destruction of tangible property. Seller shall not be required to indemnify Owner to the extent that any claim, suit, demand, liability, loss or damage arises out of or results from the acts or omission of Purchaser, or any third party under the reasonable direction and control of Owner.

SECTION 5 - COMMERCIAL INFORMATION

5.1 BUDGET PRICING

Amerair Industries will design, fabricate, and supply the Sodium Bicarbonate Injection System and all associated equipment that has been described herein – excluding listed options, FOB SHOP for the Price of:

**Two Million, Eight Hundred Thousand
U.S. Dollars and 00/100 cents. . . . . $ 2,800,000**

5.2 OPTIONS

Amerair will provide a field erection advisor per Section 3, Article QQ
for a price adder of : . . . . **$ 26,732**

Amerair will provide start up assistance per Section 3, Article QQ of this proposal
for a price adder of: . . . . **$ 39,685 ***

Note: Services quoted are in excess of those specified due to added requirements for specialized equipment such as mills and feeders.

5.2.1 VALIDITY AND ESCALATION

Pricing stated in Articles 5.1 and 5.2 are valid for 60 days from January 20, 2017 but subject to escalation in accordance with:

Due to current volatility in the steel market, material escalation (if any) will be based on AMM (American Metals Market) published price index for hot rolled carbon steel and on the North American Stainless published priced index stainless steel. Pricing included in this proposal is based on today's published index. Any increase in steel costs between date of proposal and material procurement above this benchmark will be to customer's account. (Example: If steel increases $.03/per pound, this would increase the cost of a 30,000 lb. tank as follows: 30,000 lbs. x 3¢ = $900). (Note: Steel is typically procured anywhere from 2 weeks after returned approval drawings to approx. 6 weeks prior to shipment).

5.3 PROPOSED TERMS OF PAYMENT (TO BE NEGOTIATED)

All payments shall be made by Purchaser to Amerair Industries, LLC, Post Office Box 2705, Woodstock, GA 30188 according to the following progress billing schedule:

- **10%** of the total contract price due upon written Purchase Order.
- **10%** of the total contract price due upon submittal of approval drawings including GA’s, structural loads, and P&ID’s.
- **30%** of the total contract price due upon receipt of major plate steel at plate fabricator’s shop.
- **45%** of the total contract price due upon delivery of baghouse modules and manifolds at site.
- **5%** retainage final payment due upon completion of startup, but not to exceed 60 days after delivery of baghouse modules.

- All payments are due net 30 days.
- Taxes and duties are not included.
- Pricing is valid for 45 days from date of proposal

Taxes, tariffs, and duties, if applicable, are not included. AMERAIR INDUSTRIES can supply additional field services upon request under the following conditions and rates:

1. All travel and living expenses to be invoiced at the incurred cost. Travel time portal to portal will be invoiced at normal rate.
2. a) For normal work hours between 8:00 a.m. and 5:00 p.m., Monday through Friday, the hourly rate is $ 125.00/hour or $ 1,000.00/8 hour day.
   b) For overtime hours, not including Sundays and holidays, the hourly rate is $187.50/hour or $ 1,500.00/8 hour day.
   c) For hours of work on Sundays and holidays the hourly rate is $250.00/hour or $2,000.00/8 hour day.

5.4 TERMS AND CONDITIONS

Amerair has reviewed the contract documents and has submitted “red line” changes within the document file.

5.5 PRELIMINARY SCHEDULE

To be Determined but delivery will be accomplished within the necessary time for project completion.

SECTION 6 - EXCEPTIONS & CLARIFICATIONS

Section Exception/Clarification

Supply, specifications, and scope are limited to those given in all Sections and Articles of this Proposal.

APPENDIX K

DUST CONTROL PLAN

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United States Army Garrison Alaska

Fort Wainwright
Dust Control Plan

September 2003

Fugitive Dust Control Plan

Fort Wainwright, Alaska

Prepared by
United States Army Center for Health Promotion and Preventive Medicine
Alaska Field Office
In Conjunction With
Oak Ridge Institute for Science and Education

September 2003

TABLE OF CONTENTS

SECTION 1 - INTRODUCTION

This Fugitive Dust Control Plan has been prepared for Fort Wainwright, Alaska to meet the requirements of Air Quality Control Permit (AQCP) # 236TVP01, Condition 52 (Appendix D). The plan is designed to control fugitive dust emissions for the sources identified.

Background information describing the installation is provided in Section 1. Section 2 identifies the fugitive dust sources on the installation. Section 3 outlines the best available control measures (BACM) that can be used to prevent particulate matter from being emitted into the ambient air and leaving the installation boundary. Section 4 details the monitoring, reporting, and record keeping requirements to address visible emissions, the deposition of particulate matter, and public complaints associated with the generation of fugitive dust from the installation's operations. A schedule for reporting deviations from the plan is also included in Section 4.

1.1 Topographical Description

The installation is located on the flood plain between the Chena and Tanana River in Fairbanks, Alaska. Fairbanks and Fort Wainwright are located within interior Alaska which is bounded by the Brooks Range to the north and the Alaska Range to the south. The installation covers approximately 943,000 acres including the Yukon Training Command Area. The installation is located 500 feet above sea level, 64° 49′ latitude and –147° 38′ longitude.

1.2 Climate

Interior Alaska experiences a strongly continental climate characterized by low annual precipitation, low humidity, low cloudiness, and large diurnal and annual temperature ranges. Air temperature extremes range from -50° to +35° C. The mean annual temperature of -3.3° C in Fairbanks facilitates permanently frozen soils (permafrost) on north-facing slopes and poorly drained lowlands. July is the warmest month with an average daily temperature of 16.4° C. January is the coldest with an average temperature of -24.9° C. The average number of days with freezing temperatures is 233 annually and freezing temperatures have been reported in every month except July.

The average annual precipitation in Fairbanks is 11 inches. Approximately 35 percent of the annual precipitation falls as snow from mid-October through April. Maximum snow depths, averaging 30 inches, are commonly reached in February and March. August is the wettest month with an average precipitation of two inches.

1.3 Land Use Description

The installation is subdivided into several land use categories. Within the cantonment area, there are approximately 550 buildings including housing, offices and mission support services. Other land uses on the installation include military training ranges and recreation. There are approximately 34 miles of paved roads and 183 miles of unpaved roads on the installation. The total area encompassed by roads exceeds 8.6 million square feet. There is one public elementary school on the installation with a student and staff population of over 650.

1.4 State Regulatory Requirements

The Alaska Department of Environmental Conservation (ADEC) regulates air quality under Title 18 of the Alaska Administrative Code (AAC) Chapter 50. Fugitive dust control requirements are defined in 18 AAC 50.045(d) and require an industrial activity or construction project to take reasonable precautions to prevent particulate matter from being emitted into the ambient air. The AQCP # 236TVP01, Condition 52, requires reasonable measures be instituted to control fugitive dust releases from industrial activities, construction projects, or the handling, transportation, and storage of bulk materials.

SECTION 2 - IDENTIFICATION OF FUGITIVE DUST EMISSION SOURCES

This section describes the affected sources present at Fort Wainwright regulated by Condition 52.1 (a) of AQCP # 236TVP01. The following sources are considered to be the major contributors to fugitive dust on Fort Wainwright.

- Demolition, Earthmoving, and Construction
- Landfill Operations
- Ash Disposal Operations
- Gravel Quarry Operations
- Uncovered Storage Piles
- Vehicular Traffic on Unpaved Roads and Unpaved Parking Areas
- Operation of Street Sweepers

A more detailed description of these emissions sources is provided in the following subsections. Seasonal activities such as street sweeping and gravel quarry operations only occur during the summer months and surveillance will be limited to the months in which the activities occur.

2.1 Demolition, Earthmoving, and Construction

During demolition, earthmoving, and construction projects, sources of fugitive dust emissions may include:

- The activity of earth moving during demolition, construction, or renovation itself
- Use of unpaved access roads by vehicles entering and exiting the site
- Track-out of soil onto paved roads from unpaved access roads
- Stockpiling of excavated soil or demolition material
- Transfer of material to haul trucks
- Transportation of material (gravel, soil, debris) to and from the site
- Increased vehicular traffic from privately owned vehicles to the construction site

2.2 Landfill Operations

The installation operates one 46 acre landfill that is located approximately one mile north of the cantonment area. The landfill is regulated under Solid Waste Disposal Permit # 0131-BA003. The landfill accepts construction debris, human waste, soils, ash, and asbestos. The landfill does not accept household generated waste. Asbestos waste is segregated in the southeast corner of the landfill and is clearly marked.

During landfill operations, sources of fugitive dust emissions include:

- Use of unpaved access roads by vehicles entering and exiting the site
- Transportation of waste and fill material to the site
- Stockpiling of waste and fill material
- Excavation and earth moving activities to prepare areas for fill
- Dumping and spreading of materials
- Track-out of soil onto paved roads from unpaved access roads

2.3 Ash Disposal Operations

The installation's Central Heating and Power Plant (CHPP), generates approximately 19,000 tons of coal ash per year. This ash is transported to the landfill for disposal. Approximately 6-8 truckloads of ash are removed from the CHPP each day.

The loading of the ash trucks occurs outside of the main CHPP building. Two chutes extend from the southwest corner of the CHPP into the truck loading area. The fixed chute carries wetted bottom ash from the ash collection unit to the truck bed. Once full, the load is leveled and a cover extended over the bed of the truck. The cover is tied down to minimize dust generation during transport. The telescoping chute is used to load fly ash. The telescoping chute consists of two concentric cylinders. The inner cylinder loads ash while the annulus draws a vacuum to capture displaced air and dust from the enclosed truck bed. Currently, fly ash is collected from the multiclone particulate control devices. In the future, a larger volume of fly ash will be collected from the baghouses. When weather permits, the ash hauling trucks are washed to minimize fugitive dust generation from the truck exterior.

During the process of ash disposal, sources of fugitive dust emissions may include:

- Loading of ash from the chute into trucks
- Use of unpaved access roads
- Transportation of ash to the landfill
- Dumping and spreading of ash at the landfill
- Fugitive emissions from the transportation truck's exterior

2.4 Gravel Quarry Operations

Gravel for the installation is obtained from a pit located north of Chippewa Avenue, near the Old Badger Road intersection. The gravel is bailed from the water filled pit and stockpiled for use in various projects. The water associated with the dredging activities minimizes dust production during gravel extraction. The size of the gravel extracted from the pit is suitable for most of the installation's needs, making crushing or sifting unnecessary. Since there is little to no processing required, the gravel can be used without the production of additional dust from a rock crusher.

During gravel quarrying operations, sources of fugitive dust emissions may include:

- Use of unpaved access roads by vehicles entering and exiting the site
- Stockpiling of gravel
- Transfer of gravel to haul trucks
- Transportation of gravel to construction sites

2.5 Uncovered Storage Piles

Fort Wainwright maintains uncovered storage piles of coal, gravel, and soil. A detailed description of each of these categories is provided below.

2.5.1 Coal Storage Piles

The CHPP maintains an on-site reserve of approximately 22,500 tons of coal. The coal reserve is located at the southern end of the CHPP on the eastern edge of the cooling ponds. This reserve is used when there is an interruption in coal delivery or the rail car unloading system requires maintenance. It is the policy of the CHPP to minimize coal dust generation through the use of the reserve pile only when necessary. Standard operating conditions at the plant allow daily coal deliveries by rail to supply the fuel needs of the plant.

2.5.2 Gravel Storage Piles

Large gravel storage piles are kept at the Old Badger Road gravel pit as reserves. Major construction projects may also have storage piles locally.

2.5.3 Soil Storage Piles

Contaminated soils bound for thermal remediation are stored south of the CHPP at the Chip Barn. This area may contain multiple piles of soil awaiting remediation. Separate piles are made for each remediation site and these piles vary in size according to the amount of soil remediation required at the individual construction site. The area south of the cooling ponds is also used as a soil storage area. Landscaping activities on the installation may require temporary soil storage piles as well. These soil piles are not stored in the same area as contaminated soils.

Fugitive dust emissions originating from storage piles and associated activities may include:

- Use of unpaved access roads
- Stockpiling of material
- Transfer of material to haul trucks
- Transport of material to other locations
- High wind events

2.6 Vehicular Traffic on Unpaved Roads and in Unpaved Parking Areas

The Fort Wainwright cantonment area contains approximately 30 miles of unpaved roads and 21 miles of unpaved parking areas that receive regular use. The contribution of these roads and parking areas to fugitive dust emissions is dependent on weather conditions and usage patterns. Appendix B contains tables that list the unpaved roads and unpaved parking areas. The tables also indicate the paving priority that is currently assigned to a road or parking area. The priority is based on estimated usage and the potential to affect surrounding areas. Appendix C contains a map showing the location of unpaved roads and unpaved parking areas.

2.7 Street Sweeper Operations

Fort Wainwright operates a TYMCO 600 and two FMC Model 984 street sweepers. In addition, Bobcats and lawn tractors are fitted with broom attachments for cleanup of narrow streets and sidewalks. The street sweepers have a built-in watering system to minimize fugitive dust entrainment during operation. To further suppress the generation of fugitive dust, a water truck is used to wet the area prior to use of a street sweeper or powered broom. Annual street sweeping operation occurs during the months of April through September.

Fugitive dust emissions originating from street sweeping activities may include:

- Operation of street sweepers without the dust suppression system active
- Insufficient watering of the area prior to street sweeping or powered broom activity

SECTION 3 – FUGITIVE DUST CONTROL AND MITIGATION MEASURES

This section introduces the fugitive dust control and mitigation measures that will be used to control dust emissions on the installation. This requirement is identified in Condition 52.1(b) of AQCP # 236TVP01. The control measures provided are derived from guidance generated by the South Coast Air Quality Management District (SCAQMD) of California and Maricopa County, Arizona. Both areas suffer from severe particulate matter problems and are leaders in the development of effective control strategies.

3.1 General Control Measures

General control measures include watering or revegetation of disturbed surface areas, chemical stabilization, reduction in vehicle trips and speeds, reduction of surface wind speed, covering, and paving. Use of a water truck is usually the most common means of dust control. It is inexpensive, but its effects are also short lived. The use of hygroscopic chemicals, such as; calcium chloride can be used to attract moisture from the air keeping unpaved surfaces damp and provide longer-term dust suppression. Unfortunately, these methods are more costly, may have adverse effects on plant and animal life, and may not be as effective in a dry climate like Fairbanks, Alaska. Reduction of wind speed through the use of windbreaks or enclosures is usually impractical due to cost and land availability. Paving of parking lots and heavily traveled roads is a permanent solution, but is also very expensive.

3.2 Specific Control Measures

The BACM for actions that have the potential to generate fugitive dust are listed below:

BACM for Demolition, Earthmoving, Excavation, Stockpiling and Transport

Control Measure	**Description**
Pre-grading planning	Grade each phase, timed to coincide with the construction phase, or grade entire project area, but apply chemical stabilizers or ground cover to graded areas where construction phase begins more than 60 days after grading phase begins.
Pre-grading watering	Apply water via trucks or hoses to depth of proposed cuts prior to construction and land clearing.
Post-grading watering	In active earthmoving areas, apply water at a sufficient frequency to prevent visible emission of greater than 20% opacity.
Chemical stabilizers	Hygroscopic chemicals that attract moisture to the soil surface. Effective in areas not subject to daily disturbances.
Wind fencing	Use 3 – 5 foot barriers with 50% or less porosity. Locate barriers adjacent to roadways or urban areas that can be affected by windblown material leaving the site.
Wind Awareness	Cease operations during high wind events if possible. If not possible, use watering to control emissions.
Cover haul vehicles	Entire surface area of hauled earth should be covered once vehicle is full or maintain at least 1 foot of load free board.

BACM for Unpaved Roads and Parking Areas

Control Measure	**Description**
Paving	Permanent solution but expensive. Requires street sweeping/cleaning if subjected to dust accumulation.
Chemical Stabilization	Vendors can supply information as to application methods and concentrations to meet established specifications.
Watering	Apply in sufficient quantity to keep surface moist. Application frequency will depend on soil type, weather conditions and vehicular use.
Reduced Speed Limits	10 mph maximum during construction activities. Use in conjunction with watering to prevent visible emissions.
Reduce Vehicular Trips	Access restriction or redirection of traffic to reduce vehicle trips.
Gravel	Gravel maintained to a depth of four inches can be effective in removal of soil from vehicle tires.

BACM for Storage Piles

Control Measure	**Description**
Wind sheltering	Enclose in silos, or install three sided barriers, with no more than 50% porosity, equal to height of material.
Watering	Apply water using spray bars, hoses and water trucks at a sufficient frequency to keep the surface moist.
Chemical stabilizers	Use on storage piles not subject to frequent disturbances.
Wind Awareness	Cease operations during high wind events if possible. If not possible, use watering. Load and unload on downwind side of pile.
Use of Covers	Use tarps, plastic, or other material that works as a temporary cover, and anchor the material to prevent wind from removing the cover.

SECTION 4 - MONITORING AND RECORDKEEPING

Surveillance of the fugitive dust sources identified in Section 4.1 will include visual surveys . If fugitive dust emissions are observed, the observer will suggest appropriate methods to control emissions and ensure their implementation. The observer will also survey the surrounding area to assess the impact of fugitive dust. An example of a fugitive dust survey form which may be used is included in Appendix A. The results of fugitive dust surveys will be kept on file as well as records of complaints, and corrective actions taken.

4.1 Monitoring

During fugitive dust surveys, the following sources will be observed:

- Construction, Demolition, and Earthmoving Projects
- Landfill Operations
- Ash Disposal
- Major Unpaved Roads
- Open Storage Piles
- Gravel Pit Operations (Seasonal)
- Street Sweeping Operations (Seasonal)

4.2 Record Keeping

Records will be maintained for fugitive dust surveys conducted, public complaints received, reported deviations, and records documenting corrective actions taken to address complaints and deviations.

4.3 Deviations

Deviations from the Fugitive Dust Control Plan will be reported to the Alaska Department of Environmental Conservation when a deviation is discovered.

APPENDIX A

FUGITIVE DUST CONTROL SURVEY FORM EXAMPLE

Appendix A: Fugitive Dust Survey Form

Fort Wainwright, Alaska

Activity Observed: Construction - Earthmoving - Landfill - Ash Disposal - Quarry - Storage Piles - Unpaved Areas - Street Sweeper

Observer:________________________ **Date:**__________

					Mitigation Measures														
Location	**Dust Source**	**Wind Speed and Direction**	**Time**	**Visible Emission**	Watering	Chem. Stabilization	Timing	Reduced Speed	Trip Reduction	Gravel	Covering	Load Free Board	Bedliners	Cleaning	Wind Fences				
				Y N															
				Y N															
				Y N															
				Y N															
				Y N															
				Y N															
				Y N															
				Y N															
				Y N															

Comments:

APPENDIX B

UNPAVED ROADS AND UNPAVED PARKING AREAS

Appendix B: Unpaved Roads And Parking Areas

Fort Wainwright, Alaska

Table 1: Unpaved Roads

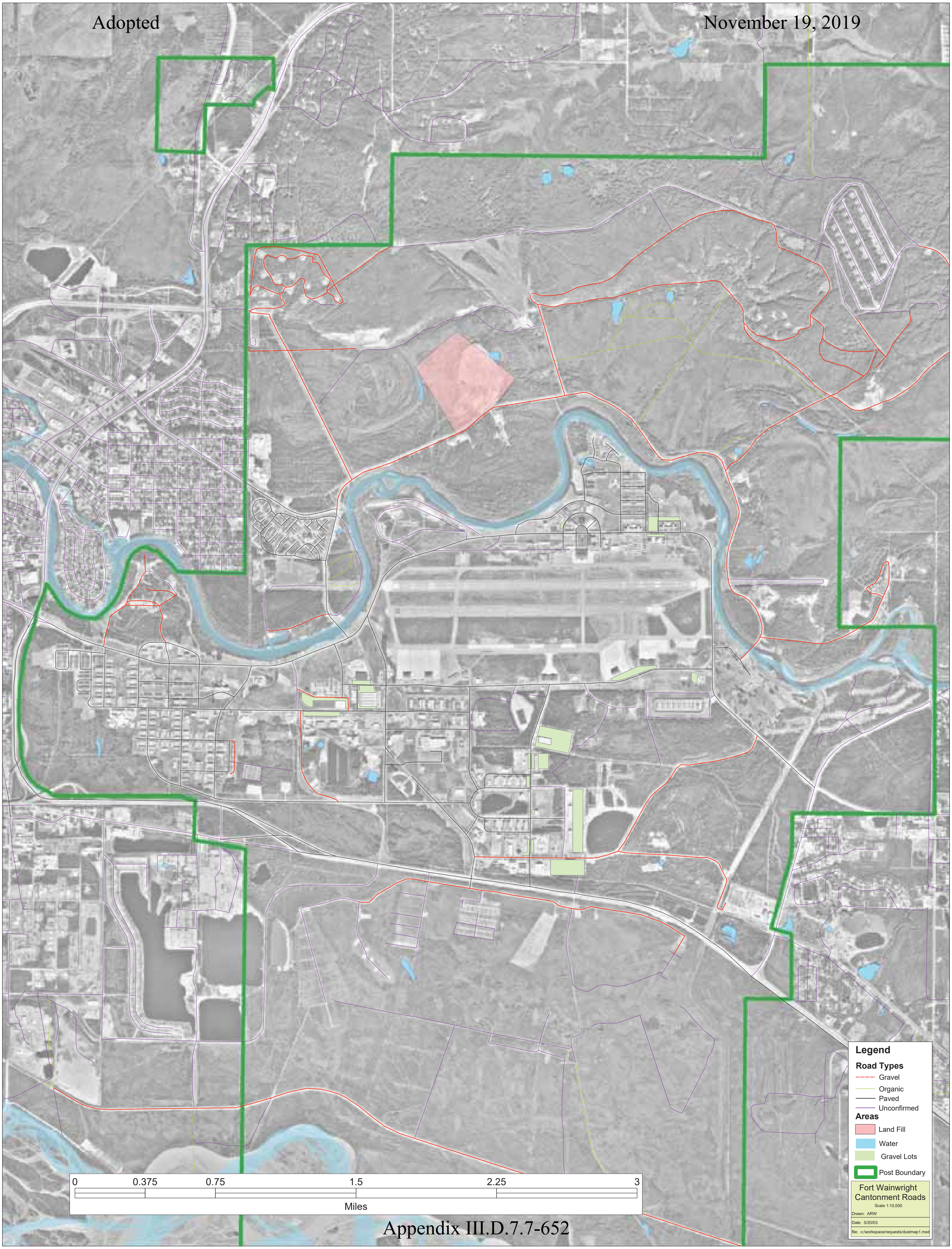
PRIORITY	NAME	LENGTH (FEET)	LENGTH (MILES)
1	River Rd	19,380	3.7
2	Range Control Dr	10,042	1.9
3	Glass Dr	1,459	0.3
4	Tamarack Dr	2,655	0.5
5	Applegate Dr	1,926	0.4
6	Chippewa Ave	8,194	1.6
7	Old Badger Rd	5,557	1.1
8	Ski Rd	2,629	0.5
9	Skeet Range Loop	2,238	0.4
10	DRMO Rd	1,679	0.3
11	West Rd	7,299	1.4
12	Lagoon Rd	2,201	0.4
13	DOL Rd	1,302	0.2
14	Cooling Plant Rd	1,721	0.3
15	Canol Service Rd	5,306	1.0
16	ASP Loop	5,182	1.0
17	Sage Hill Rd	3,878	0.7
18	Approach Hill	2,799	0.5
19	Golf Course Trail	2,490	0.5
20	Old Birch Hill Rd	6,981	1.3
21	Birch Hill Loop	13,441	2.5
22	Birch Hill Rd	15,516	2.9
23	Ammo Rd	34,228	6.5
24	Powerline Trail	1,038	0.2

TABLE 2: Unpaved Parking Areas

PRIORITY	DESCRIPTION
1	East of building 4050.
2	North, West, South sides of buildings 3018-3022.
3	South of building 3015.
4	North of building 3030.
5	North and West of building 1001.
6	North of BLM Headquarters
7	South of buildings 2085 and 2077 (Hangars 6-8)
8	North of buildings 3566 and 3567 and West of 3570.
9	West of building3023.
10	West of building 2062.
11	Southeast of building 1054.
12	East of buildings 3479 and South of 3477.
13	West of building 3485.
14	Surrounding building 3490.
15	West of building 3438.
16	East of building 3419.
17	West of building 3438.
18	East of building 3421.
19	Surrounding building 2295.
20	East of buildings 3492, 3394, and 3496.
21	North of building 3503.

APPENDIX C

MAP OF UNPAVED ROADS AND UNPAVED PARKING AREAS


Legend
Road Types
Gravel
Organic
Paved
Unconfirmed
Areas
Land Fill
Water
Gravel Lots
Post Boundary
Fort Wainwright
Cantonment Roads
Scale 1:10,000
Drawn: ARW
Date: 5/20/03
file: c:/workspace/requests/dustmap1.mxd
0
0.375
0.75
1.5
2.25
3
Miles

APPENDIX D

ALASKA AIR QUALITY CONTROL PERMIT #236TVP01 CONDITION 52

49.4 No person shall dispose of halon except by sending it for recycling to a recycler operating in accordance with NFPA 10 and NFPA 12A standards, or by arranging for its destruction using one of the following controlled processes:

a. Liquid injection incineration;

b. Reactor cracking;

c. Gaseous/fume oxidation;

d. Rotary kiln incineration;

e. Cement kiln;

f. Radio frequency plasma destruction; or

g. An EPA-approved destruction technology that achieves a destruction efficiency of 98 percent or greater.

49.5 No owner of halon-containing equipment shall allow halon release to occur as a result of failure to maintain such equipment.

50. Good Air Pollution Control Practice. The Permittee shall do the following for Source ID(s)1 through 25:

50.1 Perform regular maintenance considering the manufacturer's or the operator's maintenance procedures;

50.2 Keep records of any maintenance that would have a significant effect on emissions; the records may be kept in electronic format;

50.3 Keep a copy of either the manufacturer's or the operator's maintenance procedures.

[18 AAC 50.030 & 50.346(b)(2), 5/3/02 & 18 AAC 50.350(f)(2) & (3), 1/18/97]

51. Dilution. The Permittee shall not dilute emissions with air to comply with this permit.

[18 AAC 50.045(a), 1/18/97]

52. Bulk Materials Handling, Construction and Industrial Activities. The Permittee shall take reasonable precautions to prevent particulate matter (PM) from being emitted into the ambient air as a result of industrial activities, construction projects, or the handling, transportation, and storage of bulk materials.

[18 AAC 50.040(e), 7/2/00]
[18 AAC 50.045(d) & 50.350(d)(1), 1/18/97]

52.1 Within 120 days of the effective date of this permit, submit to the Department and comply with a dust control plan for the facility as follows and as indicated in Condition 52.3.:

[18 AAC 50.346(c), 5/3/02]

a. Identification of the sources affected by the plan;

b. The precautions that will be taken to prevent particulate matter from being emitted into the ambient air;

c. Monitoring and recordkeeping requirements that will ensure compliance with Condition 52, for each of the following:

(i) visible emissions,

(ii) deposition, and

(iii) public complaints; and

d. A schedule for reporting any deviations.

52.2 The Permittee shall keep records of

a. complaints received by the Permittee and complaints received by the Department and conveyed to the Permittee; and

b. any additional precautions that are taken

(i) to address complaints described in Condition 52.2 or to address the results of Department inspections that found potential problems; and

(ii) to prevent future dust problems.

[18 AAC 50.350(h), 5/3/02]
[18 AAC 50.045(d), 1/18/97]

52.3 If requested in writing by the Department, within the time specified, submit a revised plan that corrects any deficiencies as raised by the Department.

52.4 The Permittee shall keep records of

a. complaints received by the Permittee and complaints received by the Department and conveyed to the Permittee; and

b. any additional precautions that are taken

(i) to address complaints described in Condition 52.2 or to address the results of Department inspections that found potential problems; and

(ii) to prevent future dust problems.

[18 AAC 50.346(c), & 18 AAC 50.350(h), 5/3/02]

52.5 The Permittee shall report according to Condition 55.

[18 AAC 50.350(g) – (i), 1/18/97]

Amerair Industries llc
The Engineered Solution to Air Pollution

Post Office Box 2705 • Woodstock, GA 30188
Phone: 678-366-0388 • Fax: 678-807-2979 • www.amerair.net

June 5, 2017

Guernsey
5555 North Grand Boulevard
Oklahoma City, OK 73112-5507

Attention: Mr. Brian A. Marshall, PE

Reference: DSI Request for Budget Information
Fort Wainwright, Alaska
Amerair Budget Proposal 170602

Mr. Marshall;

Per your request for quote for the above referenced project, Amerair Industries is pleased to submit our budget proposal for your consideration. The proposal is based on requirements submitted by e-mail as reflected in Section 1 of the proposal.

We have provided pricing and description of the SBC/Trona Injection system that is specified to meet the acid gas removal requirements. Amerair personnel offer over 30 years of dry sorbent injection experience with; Trona, and Sodium Bicarbonate. We also are experienced in the design of SBC/Trona handling and conveying systems accounting for both moisture issues as well as temperature issues that can lead to reduced activity of the reagent.

While all of these measures have been specified, Amerair typically offers these features in our standard systems. Thus, we have provided an offer in compliance with the requirements with the value added from our experience in selection of the highest performing component vendors for this application.

We trust that our package meets with your approval. If you have any questions or require additional information or explanations, please do not hesitate to contact our offices.

Sincerely,

Amerair Industries, LLC

John T. Foster
Executive Vice President Sales/Technology
cc: M. Raftis , Amerair Industries LLC

* TABLE OF CONTENTS *

SECTION 1 - DESIGN CRITERIA

Specified Operating Conditions

1.	Application:	6 x Coal Fired Boilers
2.	Fuel	Coal
3.	SO2	294 lb./hr./boiler

Environmental Design Criteria

Jobsite Location	Fort Wainwright, Alaska
Grade elevation	later
Access Engineering Code:	Per OSHA
Wind Loads	90 mph (3 sec. gust @ 33 ft.)
Seismic Loads	D
Snow Load	60 psf
Dust Density	55 pcf (volumetric); 120 pcf (structural) basis
Live Loads:	120 psf (platforms); 120 psf (landings);

SECTION 2 - SCOPE OF WORK

A. Scope Furnished by Amerair

DSI System

- SBC/Trona Silo and Silo Auxiliary Equipment w/Reagent Transfer
- Air Separator Mills w/dedicated building
- Air Separator Fabric Filter, Ductwork, I.D. Fan, Transfer Screw
- Conveying Equipment Building w/transfer hopper, feed and all conveying equipment
- SBC/Trona distribution manifolds, lances
- **CFD study for final Lance design/positioning**

- All piping and couplings within and between buildings
- One (1) Lot Controls and Field instrumentation, and engineering
- One (1) Lot Electrical Equipment and devices, and engineering
- Operation and maintenance manuals electronic copies
- Field Services and per diem rates

B. Scope Furnished by Others

- Compressed Air 65-90 psig (clean and dry to -40 degrees F) supplied to battery limits
- All reagents
- Conveying piping from injection systems to injection distribution manifolds
- Duct Flanges and access at injection locations
- Compressed Air piping to supplied equipment in Silos
- Fabric Filters
- Ductwork, I.D. Fan
- DCS (logic by Amerair)
- Emission Monitoring Equipment
- Foundations and anchor bolts for supplied equipment
- Installation of injection ports and flanges per Amerair requirements and supply
- Supply of 480 V power, 120 V power and MCC
- All wiring outside of Skids Disconnects and Silo lighting and environmental facilities
- All Electrical Engineering outside of battery limits and beyond P&ID's
- Field performance and acceptance tests
- Environmental permitting
- All Taxes, including but not limited to State, Federal, franchise, and sales and use
- Any other services not specifically included in the proposal

SECTION 3 – SYSTEM DESCRIPTION

DSI SYSTEM

SBC/Trona Silo

A. Silo Construction (Side wall height extended by 6'-6" vs. dimensions below for 230 ton capacity)

- 1 – Shop welded carbon steel industrial storage tank
- 13.5' Nominal inside diameter
- 79.00' Nominal eave height
- 54.49' Approx. straight wall storage height

Tank will have:

- 60 Degree hopper slope terminating with a 8" diameter flanged outlet
- Full skirt support with hopper outlet elevated 13.15' from base of skirt support
- 10 Degree sloped deck
- Level full capacity of 8,357 cubic feet
- Estimated working capacity of 8,057 cubic feet based on 25 degree angle of repose
- Seismic zone per IBC 2009 – Site Class D, I = 1 (Ss=48.8%; S1=16.4%)
- 90 MPH wind conditions per IBC – Exp. C, I = 1
- Loads imposed by mass flow pattern
- Design pressure & vacuum is 14 oz. positive, 1 oz. negative
- Center fill/center discharge
- 20 PSF Deck live load
- Storage of free flowing sodium bicarbonate
- Product weight of 50 PCF volume, 70 PCF for design
- Ambient operating temperature

Interior coating:	Mill Finish	
Interior skirt coating:	Polyamide epoxy	2.0 mils min. DFT
Exterior coating:	Tri-Coat System	14.5 mils min. DFT
	Inorganic zinc (3 mils min. DFT)	
	Devran 223 Epoxy (5 mils min. DFT)	
	Devthane 349QC (6.5 mils min. DFT) – per color selection	

Note: All coatings are applied over an SP10 near-white surface profile.

- Interior weld profile: Smooth, not flush
- Cylinder: Full penetration double butt welds on all vertical and circumferential welds
- Skirt (if applicable): Full penetration double butt welds on all vertical and circumferential welds
- Hopper sheet seam welds: Full penetration double butt welds
- Hopper outlet cone (if applicable): lap joint, double fillet weld
- Deck to Cylinder: Double fillet weld
- Hopper to cylinder: PJP single bevel weld
- Accessories and nozzles: Double fillet weld

B. **Accessories**

- Touch-up coating for interior/exterior
- Anchor bolts & nuts
- 1 – 3' x 6'8" White HEAVY-DUTY industrial walk-in door in skirt at platform elev.
- 1 – 6' x 6'-8" White HEAVY-DUTY industrial walk-in double door assembly in skirt (above base girder – not flush)
- 1 - 20" Diameter center roof dome with cover plate
- 1 – 24" Diameter combination manway pressure/vacuum relief valve (2 oz. pressure, 0.5 oz. vacuum)
- 1 - 36" Sq. flange for bin vent filter – 1400# max. load (Wind bracing members are not included)
- 1 – Complete 4" Diameter Sch. 40 carbon steel fill line assembly, with brackets (HDG), two (2) std. sweep elbows, 4-Bolt couplers and quickie line adapter connection with dust cap (TC std. dimensions and construction) (ships loose)
- 1 – Truck fill bracket
- 3 – 1 1/2" Diameter 3000# NPT half coupling for level indication
- 1 – 4" Dia. stub nozzle for fill in center dome
- 1 – 6" Diameter Flange on deck for level indication – designed for 250# max. dead load
- 2 – 24" Sq. reinforced opening in skirt for equipment penetration
- 1 – Full Diameter smooth bar grating platform at 8' elevation in skirt – (ships loose)
- Deck perimeter guardrail – OSHA – HDG (TC std. construction)
- Bolted outside ladder from grade to eave– HDG – OSHA – complete with safety chain (TC std. construction) (ships loose)
- 1 ONLY – Bolted straight stairway, 30" blistered treads, interior and exterior rails, complete with (1) large step-off platforms from grade to door at 8' elevation - OSHA – HDG (TC std. construction) (Ships loose)

C. **Fill Line (Field Installed)**

- Silo fill line assembly
- 4” Schedule 40 carbon steel pipe
- One target box with clean-out port
- One 90° long radius elbow
- Compression type couplings
- One malleable iron truck fill adapter with dust cap
- One NEMA 4 limit switch

Shipped loose

D. **Truck Unloading Panel (Field Installed, Wired)**

- Truck unloading operator station
- NEMA 4X 304 stainless steel enclosure
- Indicating lights
- Selector switches
- Alarm siren
- Push button
- Terminal blocks

Shipped loose for field install by others

E. **Silo Level Indicators (Quantity of 3) (Field Installed, Wired)**

- Rotating paddle type
- Stainless steel paddle
- NEMA 4 polyester-coated aluminum housing and cover
- One single-pole, double-throw switch
- 120 volt, 1 phase, 60 hertz, low torque slow speed synchronous motor

Shipped loose

F. **Bin Vent (Field mounted, piped, wired to prevent damage in shipping)**

- Pulse jet type
- Carbon steel housing
- 311 square feet of pleated polyester w/PTFE filter cloth
- Solenoid valves
- Pressure differential indicator and switch

- Sequence timer
- High efficiency backward curved radial fan with 3 HP, 230/460/3/60 PREMIUM efficiency induction motor
  Shipped loose

G. **Bin Vent Air Line Assembly**

- One manually operated brass isolation ball valve
- One combination filter/regulator
- One pressure gauge
- Lot of ¾” galvanized steel pipe

H. Hopper Aeration (Solimar or Approved Equal w/local control)

- Total 16 units
- 240 gallon air receiver
- Required solenoid valves
- Pipe and pipe header
- **Field installed – Field wired to controller, by Erection Contractor**

I. Silo Discharge Knife Gate Valve

- 8” diameter
- Cast SS body
- SS 304 stainless steel gate
- SS 304 stainless steel metal seat
- Teflon packing
- Electrically actuated
- Emergency hand wheel
- **Field installed**

J. Rotary Air Lock Feeder
- 8” diameter
- 1,000 lb./hr. design feed rate
- Cast iron body
- 8 vane rotor
- Fixed blades with beveled edges
- 1 HP, TEFC motor 230-460/ 3/60
- Chain drive and guard

- **Field installed, Factory wired to disconnect**

K. Diverter Valve

- One inlet and two outlets
- Mild steel construction
- Polyurethane Rubber flap seal
- Double acting pneumatic air cylinder
- Single coil, spring return
- Two limit switches
- Vendor standard finish paint
- **Field installed and piped from Mezzanine receiver**

L. Cross Screw Conveyors to Mills (Quantity 2)

CONVEYOR COMPONENT	DESCRIPTION:
DESIGNATION	9" Diameter Screw Conveyor
CONVEYOR LENGTH	22'-1" OAL Approximate
TYPE MATERIAL HANDLED	Sodium Bicarbonate
MATERIAL DENSITY	50 PCF
CONVEYOR CAPACITY	5 TPH 200 CFH
SCREW POSITION	15 Degree Incline Approximate
SCREW RPM	40 RPM
SCREW DESCRIPTION	9S312, RH, Full Pitch, Type 1 Weld w/Bare Pipe Over Discharge
FLIGHTS	3/16" Plate Mild Steel
PIPE	2" SCH 40
TROUGH TYPE	10 Gauge Formed Flange U-Trough
TROUGH ENDS SEALS	Waste Pack Seal
TROUGH % FILL	30 %
HANGERS	(1) Style 226
HANGER BEARINGS	(1) Wood Style 226
SHAFT DIAMETER	1 1/2"
END BEARINGS	4-Bolt Flange Ball Bearing
INLET	(1) Inlet, Standard with Flange
DISCHARGE	(1) Discharge, Standard with Flange
COVERS	14 Guage Flanged, Gasketed & Bolted On 24" Centers
PAINT/CLEANING	Orthman Blue Urethane Exterior Surfaces
SPEED SENSOR	N/A
OTHER	
OTHER	
DRIVE COMPONENTS	**Class II Service Selection**
REDUCER	Dodge TA 1107H31 x 1 1/2" Screw Conveyor Drive
MOTOR	3 HP Tefc, WEG Electric W22 Series Inverter Duty
MOTOR MOUNT	Dodge TA 1107 MM
BELT GUARD	Dodge TA 1107 BG
BELT DRIVE	Included--(2) Groove Minimum

<u>Air Classifier Mill System</u>

M. Mill Building 18' x 18' x 20'

WALLS

STEEL FACINGS BOTH SIDES OF WALL (S/S): 72 LF @ 20' ft tall

The walls shall be 3" thick composite sandwich panels. The exterior and interior shall be 26 GA stucco-embossed steel, pre-painted white. The core shall be of 99#, 3/4" cell, 11% phenolic-resin impregnated structural Kraft honeycomb. Panel division/finish strips shall consist of color coordinated vinyl "H" connectors that shall not protrude more than 1/16" beyond the finished wall panel. The entire panel shall be laminated together using a solvent free two-part polyurethane adhesive and pressure. The panels shall have formed edge connectors that are capable of being friction locked without mechanical fasteners using a full-length joint without through metal connectors. The joint shall allow lateral expansion and contraction. This shall result in a structural panel that shall not require support columns every 4'.

GABLE CLASS A ROOF W/ 9” OVERHANG

POLYSTYRENE ROOF -3", 3-PLY: 1,019 square feet

The roof shall be 3" thick composite sandwich panels. Both sides shall be stucco-embossed aluminum pre-painted white. The core shall be of 1 lb. density polystyrene foam. The entire panel shall be laminated together using a solvent free two-part polyurethane adhesive and pressure. The panels shall have formed edge connectors that are capable of being friction locked without mechanical fasteners using a full-length joint without through metal connectors. The joint shall allow lateral expansion and contraction.

wall & roof core

Polystyrene:

The polystyrene core shall have the following mechanical properties;

Shear strength (flatwise)	18 -22 PSI
Shear Modulus (flatwise)	280 - 320 PSI

The water absorption rate shall be less than 4%

INSULATION

All wall and roof panels shall be insulated to a minimum R value of 11.

NO CEILING

DOORS

20 GAUGE insulated STEEL double doors WITH 1/2 GLASS: 1 Each

The door(s) shall be **72"w X 84"h X 1 3/4"** thick and shall be constructed of 20 gauges hot dipped galvanized steel, mill treated for proper paint adherence. The door shall have top and bottom channel of 16 gauge steel projection welded to door skins on no less than 2" centers. The top channel is to be flush while the bottom channel is to be inverted. The hinge preparations are to be 9-gauge steel reinforcement’s projection welded to the door skins in six places each. Hinge preparation is to be cut through the doors and provided with reversible filler plates to allow building site handling. Standard hinge preparation is to be 4-1/2" regular weight .134" hinge, conforming to ANSI A1567, three preparations. The doorframe shall be 16-gauge single "rabbit" commercial quality steel. The frame shall be pre-mortised for application of matching hinges and striker set of the door. The door shall be supplied with all necessary hardware as to meet local and state code requirements. The door shall be fabricated as to include 1//8" tempered safety glass in the upper half. The windows shall measure approximately 22"w X 36"h.

NO WINDOWS

ELECTRICAL

ELECTRICAL PACKAGE - CONCEALED: 1 EACH

The electrical package shall consist of 1/2" EMT cable concealed in the panel and attached to flush mounted 2x4 boxes at receptacle and switch locations. There shall be **(1**) wall switch, **(9)** duplex receptacles, **(0**) 3 way wall switch, **(0)** telephone/computer prep, **(5)** fluorescent fixtures (100 foot candles at desk height). This package shall meet NEC (current edition). Wiring is not included.

125 AMP SINGLE PHASE 14 SPACE MAIN LUG BREAKER BOX: 1 EACH

The electrical service shall include an indoor load center of sufficient amperage and circuit capacity as to handle all lighting loads, receptacles and HVAC systems. NOTE: The entire electrical system for the modular building shall be in accordance with the National Electrical Code and shall meet all N.E.C requirements

Climate Control

AIR CONDITIONING - COOLING & HEATING: 1 EACH

The air conditioner shall be 18,000 BTU's of cooling and 11,100 BTU's of heating. The unit shall be a through-the-wall type with panel preparation included. The unit shall be 230/208V, 60HZ, 20 AMP

NO FLOORS

N. Air Classifier Mills (Quantity 2)

General Process Specifications:

1.	Process Material:	Sodium BiCarbonate	
2.	Material Characteristics:	Feed Bulk Density: Inlet Feed Size:	TBD 50 – 100 microns
3.	Milled Product Size	D90 = 15 microns	
4.	Capacity:	> 5,000 lb/hr	

General Equipment Specifications

1.	Materials of Construction	Carbon steel		
2.	Paint System	Manufacturer's standard		
3.	System Design	Pressureless construction		
4.	Electrical Utility	Main:	480 V / 3 Phase / 60 Hz	
5.	Controls & Instruments (Located in process area)	Controls: Instrumentation:	110V/1PH/60Hz Analog: Digital:	 4-20ma DC 120 VAC
6.	Area Classification	Non-Hazardous		

Equipment Specifications

Item 1 – Mikro-ACM® Model 300 Air Classifying Mill:

Mikro-ACM® Model 300

- Material of Construction: Cast iron / carbon steel
- Gravity-drop feed assembly consisting of a fabricated inlet funnel with inclined feed chute bolted to mill inlet flange.
- Rotor assembly: eight (8) bar hammers with Tungsten Carbide tipping
- 24 Long canted blade classifier
- Ni-Hard MD liner
- Standard baffle / shroud assembly
- Grinding chamber with inspection door and limit switch
- Structural steel base with stand legs and integral main drive belt guard.
- Automatic lubrication system.
- Constant speed 300 HP main drive motor, multi V-belt arrangement, 1800 RPM, 460 V / 3 HP / 60 Hz TEFC
- Direct connected 50 HP, 460 Volt, 3 Phase, 60 Hz, Inverter Duty 4:1 TEFC classifier motor with coupling and guard.
- Speed Pick-up Assembly for classifier wheel.
- One coat of primer and one coat of finish enamel on mild steel surfaces– HMPS standard.

Item 2 – Rotary Airlock – Mikro-ACM 300 Feeder

- Type: Drop-thru type
- Size: 10" ID Square Inlet and Outlet Flanges
- Material of Construction: Carbon steel
- Rotor: 8-vane rotor
- Beveled edges on rotor vane tips
- Chain drive
- 1.0 HP, variable speed motor, 460/3/60
- Enclosed drive guard, base & mounting
- Two (2) flange gaskets

Common to the Two Mills

Item 3 - System Blower

- Rated for 20,000 ACFM, -65" WC, 125° F
- Based on estimated site elevation of 40 ft ASL
- Flanged Inlet & Outlet
- Coupling & Shaft Guards
- Housing Drain
- Discharge Silencer
- 300 HP Inverter Duty Motor (VFD by customer)

Item 4 - Control Panel & Instrumentation

- NEMA 4 enclosure
- Allen-Bradley Compact Logix PLC
- Pushbutton style panel, with lighted pushbuttons and lamps for system motors, etc.
- Auto Mode for sequential start/stop of all equipment.
- Maintenance Mode for individual motor start/stop (Note: there are no motor running permissive in this mode.)
- Motor starters and variable frequency drives not included – to be supplied by customer and installed in customer's Motor Control Center
- One (1) Thermal Mass Flow Meter – System Airflow
- Speed transmitter for classifier speed, with digital speed display on panel
- Differential Pressure Gauge - ACM 300 Mill
- Differential Pressure Switch – Product Collector Filters
- Level Probe – Product Collector

O. Air Separator Filter and Conveyor System Transfer [Common]

1. **Equipment Selection**

• Quantity of Baghouses	One (1)
• Baghouse Model	(1) WIP-26/25 210 D5 (15 x 14v)
• Number of compartments per baghouse	1
• Bags per baghouse	210
• Cloth area per bag, sqft (effective)	35.434
• Total cloth area, all compartments, sqft	7,441
• Gross filter ratio, single compartment (@20,000 ACFM)	2.54

2. **Construction**

• Main Housings and Clean-air Plenums	3/16" C.S.
• Tubesheets	3/16" C.S.
• Hoppers	3/16" C.S.

- Inlet & Outlet Manifolds 3/16” C.S.

3. Clean Air Plenum

- Type Walk-in Plenum
- Height 13’-6”
- Access Galvanized grating walkway along baghouse
- Access Caged Ladder w/rest platform

4. Hoppers

- Configuration Pyramid
- Slope angles°: valley / end / side 55 / 64.6 / 62.8
- Discharge 12” x 12 ft. flanged
- Discharge height (from grade) 20’-0”
- Hopper volume (effective) 281 cu. ft.
- Accessories (per hopper):
  - Access Door (24” x 24”) One (1)
  - Poke Holes (4” dia.) Two (2)
  - Strike Anvils Two (2)
  - Level switch One (1)
  - Hopper vibrators (electric) Two (2)
  - Screw Conveyor 9” x 26’(approx..) One (1)
  - Rotary Air Lock 8” One (1)

5. Filter Assemblies

- Bags
  - Quantity per baghouse 210
  - Diameter x length 5” dia. x 26’-3” long
  - Attachment Stainless steel snap ring
  - Material Polyester Felt
  - Weight (nominal) 16 ounce
  - Finish (Base) Singed

- Cages
  - Quantity per baghouse 210
  - Type Two-piece Cage
  - Wires 11 gauge, 20 vertical wires
  - Spacing 8” girth ring spacing
  - Material C.S.

6. Pulse Cleaning System

- Cleaning Manifold — 12” diameter
- Blowpipe — 3.5” dia. 1/8” wall tubing w/1-1/2” nozzles
- Diaphragm Valves — 3” diaphragm
- Header Valves — Isolation valve and drain valve

7. Access

Main platform (1)	Full Section 3’ wide Along Plenum Row
Grating	4" x 1-1/4" x 3/16"
Handrail	Two rail handrail, 1-1/4 " nominal pipe
Toeplates	4" x 1/4"
Caged Ladder (1)	From Grade to Walk In Plenum Platform

8. Surface Preparation and Painting

Exterior Fabricated Steel Surfaces

- Plate Steel (baghouse compartments, stubs)
  - Surface Preparation — SP-3
  - Paint — Macropoxy compatible
  - Finish Paint — SW Macropoxy 646 4-5 mils dft
- Cold steel (support stubs, access steel, etc)
  - Surface Preparation — SSPC-SP-3
  - Primer / Finish Paint — SW Macropoxy 646, 4-5 mils dft
- Vendor Supplied Equipment
  - Provided with Vendor’s standard paint system.

9. Controls and Instrumentation

Control System Hardware

- Pulse Cleaning Enclosures: — One (1) NEMA 4x enclosure per baghouse

Pulse Jet Cleaning Control System

- The cleaning system is fully automatic and will be initiated by overall baghouse differential pressure with a timed sequence override.
- Timer/sequencer cards provide the cleaning cycle control.

Field Instrumentation (per baghouse)

- One (1) Baghouse Differential Pressure Photohelic
- One (1) Baghouse Pulse Timer panel
- One (1) Pulse Header Pressure Gauge
- One (1) Baghouse Compartment Differential Pressure Gauge
- One (1) baghouse hopper level switch (capacitance type)

Electrical

- Screw conveyor motor 2.0 H.P. 460V/3Ph/60Hz
- Rotary Air Lock Motor 1.0 H.P. 460V/3Ph/60Hz

10. Ductwork

- Mill Pair to Fabric Filter Inlet – 24" diameter Y branch with 24" manual butterfly damper in each branch, straight riser section to fabric filter inlet, two elbows
- Fabric Filter Outlet to I.D. Fan – 32" diameter with one elbow and one transition to I.D. Fan inlet box, vibration joint.
- I.D. fan outlet stub w/silencer
- Finishing of all in accordance with 8. Above

P. Conveying Equipment Building

WALLS

STEEL FACINGS BOTH SIDES OF WALL (S/S): 128 LF @ 20' ft tall

The walls shall be 3" thick composite sandwich panels. The exterior and interior shall be 26 GA stucco-embossed steel, pre-painted white. The core shall be of 99#, 3/4" cell, 11% phenolic-resin impregnated structural Kraft honeycomb. Panel division/finish strips shall consist of color coordinated vinyl "H" connectors that shall not protrude more than 1/16" beyond the finished wall panel. The entire panel shall be laminated together using a solvent free two-part polyurethane adhesive and pressure. The panels shall have formed edge connectors that are capable of being friction locked without mechanical fasteners using a full-length joint without through metal connectors. The joint shall allow lateral expansion and contraction. This shall result in a structural panel that shall not require support columns every 4'.

GABLE CLASS A ROOF W/ 9" OVERHANG

POLYSTYRENE ROOF -3", 3-PLY: 1,019 square feet

The roof shall be 3" thick composite sandwich panels. Both sides shall be stucco-embossed aluminum pre-painted white. The core shall be of 1 lb. density polystyrene foam. The entire panel shall be laminated together using a solvent free two-part polyurethane adhesive and pressure. The panels shall have formed edge connectors that are capable of being friction locked without mechanical fasteners using a full-length joint without through metal connectors. The joint shall allow lateral expansion and contraction.

wall & roof core

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The water absorption rate shall be less than 4%

INSULATION

All wall and roof panels shall be insulated to a minimum R value of 11.

NO CEILING

DOORS

20 GAUGE insulated STEEL double doors WITH 1/2 GLASS: 2 Each

The door(s) shall be **72"w X 84"h X 1 3/4"** thick and shall be constructed of 20 gauges hot dipped galvanized steel, mill treated for proper paint adherence. The door shall have top and bottom channel of 16 gauge steel projection welded to door skins on no less than 2" centers. The top channel is to be flush while the bottom channel is to be inverted. The hinge preparations are to be 9-gauge steel reinforcement's projection welded to the door skins in six places each. Hinge preparation is to be cut through the doors and provided with reversible filler plates to allow building site handling. Standard hinge preparation is to be 4-1/2" regular weight .134" hinge, conforming to ANSI A1567, three preparations. The doorframe shall be 16-gauge single "rabbit" commercial quality steel. The frame shall be pre-mortised for application of matching hinges and striker set of the door. The door shall be supplied with all necessary hardware as to meet local and state code requirements. The door shall be fabricated as to include 1//8" tempered safety glass in the upper half. The windows shall measure approximately 22"w X 36"h.

NO WINDOWS

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ELECTRICAL PACKAGE - CONCEALED: 1 EACH

The electrical package shall consist of 1/2" EMT cable concealed in the panel and attached to flush mounted 2x4 boxes at receptacle and switch locations. There shall be **(0**) wall switch, **(13)** duplex receptacles, **(2**) 3 way wall switch, **(0)** telephone/computer prep, **(14)** fluorescent fixtures (100 foot candles at desk height). This package shall meet NEC (current edition). Wiring is not included.

125 AMP SINGLE PHASE 14 SPACE MAIN LUG BREAKER BOX: 1 EACH

The electrical service shall include an indoor load center of sufficient amperage and circuit capacity as to handle all lighting loads, receptacles and HVAC systems. NOTE: The entire electrical system for the modular building shall be in accordance with the National Electrical Code and shall meet all N.E.C requirements

Climate Control

AIR CONDITIONING - COOLING & HEATING: 2 EACH

The air conditioner shall be 18,000 BTU's of cooling and 11,100 BTU's of heating. The unit shall be a through-the-wall type with panel preparation included. The unit shall be 230/208V, 60HZ, 20 AMP

NO FLOORS

Internal Mezzanine Level for Storage Hopper and Feeders

MEZZANINE

MEZZANINE STRUCTURE AND LOAD RATING: 125 PSF – L / 360

The mezzanine floor support and loading shall consist of 5" x 5" x 3/16" square columns with 5/8" thick X 12" square plates as bases. Column loading represents the maximum weight placed on the existing floor if the mezzanine is loaded to its maximum capacity on each square foot. The end user should verify that their floor has adequate strength to support the column loading. The perimeter and intermediate support beams shall be structural beams. Joists shall consist of properly sized bar joists.

1" Bar grating Floor Decking: 880 square feet

Decking shall be composed of 1" thick 19w4 welded bar grating. The material shall be painted shop coat black. Bar grating shall be attached with saddle clamps and tek screws.

IBC STAIR SYSTEM: 1 EACH

Application – The stairs listed below meet the standards for FACTORY and STORAGE USE GROUPS with occupancies of 50 or less people.

Treads shall be 42" wide with closed risers. Tread rise shall be a maximum of 7" and tread run shall be a minimum of 11". Tread and closed riser material is to be steel diamond plate. Stair railing shall be constructed of 2" x 2" angle uprights and 1-1/2" horizontal tubes. Stair railings shall be 36" tall and shall be spaced so as to allow a sphere no larger than 21" diameter to pass through any opening.

Landings shall be sized appropriately so as to meet code requirements. The landing floor is to be constructed of steel diamond plate. Landing railing shall be constructed of 2" x 2" angle uprights and horizontal 1-1/2" tubes. Landing railings shall be 42" tall and shall be spaced so as to allow a sphere no larger than 21" diameter to pass through any opening. All landing railing shall include a 4" tall toe plate.

Application – The stairs listed below meet the standards for the BUSINESS USE GROUPS with occupancies of 50 or less people.

Treads shall be 36" wide with closed risers. Tread rise shall be a maximum of 7" and tread run shall be a minimum of 11". Tread and closed riser material is to be steel diamond plate. Stair railing shall be constructed of 1-1/2" tube. Stair railings shall include 36" tall handrails with an exterior guardrail whose overall height is 42". The handrails are to be constructed so as to allow a sphere no larger than 4" diameter to pass through any opening.

Landings shall be sized appropriately so as to meet code requirements. The landing floor is to be constructed of steel diamond plate. Landing railing shall be constructed of 1-1/2" tube. Landing railings shall be 42" tall and are to be constructed so as to allow a sphere no larger than 4" diameter to pass through any opening. All landing railing shall include a 4" tall toe plate.
FOR OCCUPANCIES LARGER THAN 50 PEOPLE THE TREAD WITDH IS TO INCREASE TO 44" W.

FASTENERS:

All wedge anchors, bolts, nuts; washers, and screws shall be supplied with the system. No additional fasteners will be needed to complete the structure.

FINISH:
All structural beams, columns, landings, handrail and gates are powder coated our standard colors. Bar joists are primed gray and are not powder coated. Special colors and powder coating the bar joists can be coated upon request. All handrails shall be painted safety yellow.

Q. Feed Hopper (on mezzanine level of conveying equipment building)

- 4’ high 60 degree x 36’ long covered feed hopper supported at the upper building level, finished in accordance with O. 8. Above
- 2.5” pipe vent line to inlet of fabric filter
- Integral reverse flight screw conveyor in 1’ wide bottom of hopper for feed distribution
- 8” flanges for Feed and Conveying trains
- 8” manual slide gates for maintenance isolation
- 8” rotary air lock valves w/0.5 H.P. drive, drop chute to feeders

Feed and Blower Trains (8 operating, 2 on-line spares) in Conveying Room

R. Gravimetric Screw Feeders on Mezzanine Level (Quantity 8) – Techweigh or Equal

- Capable of feeding 25 – 250 (FF) and 50 – 500 (ESP) pounds per hour (max) of SBC/Trona with a density of 50 lb./ft^3
- 304 stainless steel trough
- 304 stainless steel discharge spout
- 2” Solid flight feed screw with material conditioning plows
- 0.5 HP, DC drive screw, 0.25 HP hopper agitator
- Variable speed VFD drive located in the system panel
- NEMA 4X local panel controller
- **Factory installed on Feeder/Hopper/Air lock Skid**

S. Vented Hopper with Cartridge Filter (Quantity 10)

- Horizon (or Approved Equal) Air Vent Hopper
- Pulse Cleaned Cartridge Filter
- 1.0 HP Vent Fan to Silo Skirt Interior
- Pre Wired to local disconnect
- **Factory Installed as part of feeder/rotary valve skids**

T. Rotary Air Locks to Feed Lines (Quantity 8)

- 8" diameter air lock
- 450 lb/hr design feed rate
- Cast iron body
- 8 vane rotor
- Fixed blades with beveled edges
- 0.5 HP, TEFC motor 230-460/ 3/60
- Chain drive and guard
- Air purge shaft seals
- Factory wired to local disconnect
- Integrated with Air Vent Hoppers

Conveyor Skids Shop Assembled

U. Inlet Air Dehumidifier (located at top of each skid), 8 total

- Dehumidifier Munters HC-300 (shop mounted on blower skid, exhaust duct to outside silo provided but installed by Erection Contractor. Dehumidifier description per below:

Technical data - System Features

Main selections	
Electrical power source	460/3/60
Dehumidifier model	HC-300
Reactivation heater type	Electric
Desiccant type	TiGel
Full load amps (FLA)	9.7 A
Part number	30569-04
Process Airstream	
Filter size	20-3/4" x 5-3/4" x 1/2"
Filter efficiency	Metal mesh
External static Pressure	1.75 in WC
React Airstream	
Filter size	7" x 6-1/2" x 1/2"
Filter efficiency	Metal mesh
External static pressure	1.25 in WC

- Inlet Duct – 4" to 6" duct for fresh air to building wall to inlet filter
- Outlet Duct – Regenerator side exhaust duct for moist gas to outside of building
- Dry Air Duct – 4" duct of dry air to blower inlet silencer

V. Blower Packages – Base of Skid Mounted (Quantity 8)

Universal Blower Pac package to provide 300 ICFM at 6 - 10 PSIG. Including:

- Westwood EMFP-3 FilterProGENTEX DRSI-3 Gr.I Silencer Internal Universal Flex Joint
- Gardner Denver 408 Heliflow Blower Internal Universal Flex Joint
- 25 HP ODP PE 1800 rpm 460/60/3 Motor V-Belt Drive
- Base & Guard
- ProGENTEX DRS-3 Gr.I SilencerKunkle 2-Inch 337 Relief ValveExternal Universal Flex Joint Flexi Hinge 3-Inch 502 Check Valve Keystone 3-Inch Butterfly Valve Winters PFQ902 Pressure Gauge
- UE J6 Pressure Switch

Heat Exchanger and Vent Hopper Shipped Loose for Installation in Field

W. Heat Exchangers w/rack mount (Quantity 8 exchangers)

- Xchanger, Inc. Rating for Model AA-400 ref #123439

		HOT SIDE	COLD SIDE
• PERFORMANCE		HOT SIDE	COLD SIDE
• Fluid Circulated		Air	Air
• Volumetric Flow Rate		300.0 Std. ft 3/min	1,313.1 Std. ft 3/min
• Total Fluid Entering		1,350.0 lb/hr	5,909.0 lb/hr
• Liquid			
• Vapor			
• Non-Condensibles		1,350.0 lb/hr	5,909.0 lb/hr
• Vaporized or (Cond.)			
• Temperature In		160.0 °F	85.0 °F
• Temperature Out		110.4 °F	114.5 °F
• Inlet Pressure	(Absolute)	20.372 lb/in 2	14.372 lb/in 2
• Velocity	(Standard)	1,437 ft/min	1,434 ft/min
• Pressure Loss		0.10 lb/in 2	0.05 lb/in 2
• Fouling Factor		0.0001 ft 2-°F-hr/BTU	0.0001 ft 2-°F-hr/BTU
• Total Heat Exchanged:	20,598 BTU/hr		
• CONSTRUCTION			
• Design Temperature		200 °F	Not Applicable
• Design Pressure	(Gauge)	15 lb/in 2	Not Applicable
• Test Pressure	(Gauge)	15 lb/in 2	Not Applicable
• Cyclic Pressure		No	Not Applicable
• Flow Direction		Right Hand Horizontal	Vertical Up/Pull

Through
- Plate-Fin Core : Aluminum Fan Hood : Galvanized Steel
- Fan Guard : Coated Carbon Steel Venturi Frame : Coated Carbon Steel
- Drawing Number : Weight : 165 lb
- CONNECTIONS
- Process Inlet : 3 inch pipe stub
- Process Outlet : 3 inch pipe stub
- MECHANICAL EQUIPMENT
- Fan Diameter : 12 inch Motor : 1.00 HP TEFC
- Fan Qty/Speed : 1 / 3480 RPM Motor Qty/Speed : 1 / 3480 RPM
- Fan Type : 4 Blade Mill Galv. St Motor Electrical: 208-230/460/3/60

X. Piping in Conveyor Room (8 lots)

- Blower Outlet Silencer to Heat Exchanger – 3" Fernco Vibration Coupling at Blower Silencer, 3" Sch 40 carbon steel straight run, 3" Flex Hose w/quick couplings to Heat Exchanger Intlet
- Heat Exchanger Outlet to Vent Hopper Discharge Line – 3" Marine Flex Hose w/quick couplings to inlet stub of Vent Hopper transition/pipe.
- Vent Hopper Discharge Pipe to Building Outlet Stubs – 3" Marine Flex Hose w/quick couplings to Building outlet 3" Sch 40 pipe stub w/quick coupling Female end
- Building Outlet Stubs (8) – One stub for each field injection point using 3" sch. 40 pipe w/outlet quick disconnect for connection to Owner's field run pipe to Injection Distributors

Note: The four lines going to the ESP injection distributors have one redundant Feeder/Conveyor System that can be activated and attached by moving the Vent hopper discharge hose to the appropriate building outlet stub when needed.

The four lines going to the Fabric Filter injection distributors also have one redundant Feeder/Conveyor System that can be activated and attached by moving the Vent hopper discharge hose to the appropriate building outlet stub when needed.

Y. Injection Manifolds/Lances (One/Fabric Filter)

Four (4) Amerair proprietary design injection nozzles per ESP or Fabric Filter located at ports designed by **Amerair, and supplied and installed by Owner's erection contractor**.

Nozzles feature:

- Integral dynamic mixing
- 316 SS construction 1-1/2" diameter lances
- 316 SS mating flange to port flanges
- 1' diameter x 1' cylinder height (conical bottom) four (4) port injection distributor mounted at duct w/supplied brackets
- 1-1/2" SS 316 ball valve at each distributer port for on line maintenance
- 1-1/2" braided hose connections from distributer ports to lance stubs with hardware
- **Full CFD study for optimized distribution using off set angles and lengths; One study for the ESP injection duct assuming duplicate geometry for the 4 and one study for the Fabric Filter injection duct assuming duplicate geometry for the 4.**

Z. **Consumables and Preliminary Load List**

Following Page

MOTOR/LOAD	QUANTITY	HP ea.	KW total Connected	Duty %	Total KW Consumed
PROCESS EQUIPMENT					
Bin Vent Blower DSI	1	3.0	2.24	3	0.067
Hopper Rotary Airlock	1	0.50	0.38	100	0.38
Transfer Screws	2	3.0	4.48	50	2.24
Mill Air Lock	2	1.0	1.5	50	0.75
Mill Motor	2	300	448.2	50	224.1
Mill Classifier	2	50	74.7	50	37.4
Separator FF I.D. Fan	1	300	224.1	100	224.1
Fabric Filter Transfer Screw	1	3	2.24	100	2.24
Hopper Feed Rotary Airlock	1	1	0.75	100	0.75
Hopper Distribution Screws	2	3	4.48	100	4.48
Feeder Rotary Airlocks	8	0.5	3	75	2.24
Gravimetric Feeders	8	0.5	3	75	2.24
Gravimetric Feeders	8	0.25	1.5	75	1.13
Vent Hopper Blower	8	0.5	3	75	2.24
Drop Thru Rotary	8	0.50	3	75	2.24
Desiccant Dehumidifiers	8		56	75	42
Conveying blower DSI	8	25	149.4	75	112
Conveying after cooler DSI	8	1.0	-6	75	4.5
Instrument/Control	All		15	100	15
NON PROCESS					
HVAC and Heaters	6		30	0	0
VENT Fan	2	1	1.5	0	0
Lighting	5	1.2	6	0	0

Note: Non process equipment not calculated in power consumption total

Expected SBC Consumption 2778 to 4167 ton/yr. at 50%-80% removal combined FF

Expected Compressed Air Consumption = 60 SCFM, dry -40 F, 90 PSIG

AA. **Field Service and Start Up Option Pricing**

Erection Advisor: Amerair will provide the services of an Erection Field Advisor to consult with the Owner's Erection Contractor on critical phases of the equipment installation. Amerair has allowed **15 man days (8 hrs. day)** of said services with **three separate trips** to site. Additional services if required will be provided at per diem rates.

Pre Commissioning Field Services: Amerair will provide the services of a qualified field Engineer for the purposes of equipment check out to ensure that proper installation of equipment and all electrical continuity has been achieved. This phase will also include all pre commissioning testing. Amerair has allowed **15 days at 8 hrs./day** and **one trip** for this purpose. Additional services if required will be provided at per diem rates.

Start Up Services: Amerair will provide the services of a Mechanical Field Engineer and a PLC Field Service Engineer each for a period of **7 x 8 hr. days** allowed in the base pricing. This personnel will provide services during the first week of operation and also provide on site training during that period. Additional services if required will be provided at per diem rates

Per Diem Rates:

Erection Advisor:	$ 1100/day
Pre Commissioning Field Services:	$ 1100/day
Start Up Mechanical:	$ 1100/day
Start Up Electrical/Control:	$ 1200/day

‘* Travel expenses are in addition to per diem rate and billed at cost.

SECTION 4 - PERFORMANCE, GUARANTEES, & WARRANTY

4.1 OPERATING CONDITIONS

The design/operating conditions are in accordance to the Specification and as reflected in the Design Conditions Section 1 of this proposal.

4.2 PERFORMANCE

Subject to the conditions and limitations contained herein and provided the baghouse is operated within the operating conditions as set forth in Section 4.1 above the performance shall be as stipulated below.

4.2.1 SOLID PARTICULATE MATTER (PM) EMISSIONS

Covered in Fabric Filter Proposal

4.2.2 SO_2 EMISSIONS

Final SO2 emissions will be 50% to 80% less than the combined inlet Values on Proposal Section 1 Inlet Values. Testing to be the average of three, 3 hour tests conducted according to EPA method 30B.

4.2.3 HCl EMISSIONS

N/A

4.2.4 OPACITY

N/A

Non-emissions related

4.2.5 SORBENT FEED RATE (TO FABRIC FILTER INLET)

The Sodium Bicarbonate feed rate will not exceed **2778 to 4167 tons/yr. for the combined 6 units** based on specified 15 micron D-90 milled Sodium Bicarbonate. Measurement of rate shall be by gravimetric feeder instrumentation. Turndown from guarantee feed rate is further guaranteed at a ratio of 10:1 again as measured by gravimetric feeder instrumentation. Verification shall be by timed collection of lime feed.

4.2.6 FLUE GAS PRESSURE DROP

Addition of sorbent injection lances will not result in an added pressure drop greater than 0.025” water column as measured by mutually agreed upon methods at operating conditions per Section 4.1 before and after addition of injection lances.

4.2.7 POWER CONSTUMPTION

The auxiliary power consumption including all process equipment but excluding all heating, lighting, ventilation, lifting and all convenience items with “0” demand factor per the load list Section 3 Article HH will not exceed an average of **760 KW.** Consumption is to be determined by mutually agreed MCC clamp with all non-process equipment not operating.

4.2.8 NOISE

Noise from individual devices shall not exceed **85 dBA** at a distance of 3 ft. and 5 Ft.. above grade. Where measurements exceed 85 dBA due to suspected resonances or other anomaly, shop measurements for the same equipment will prevail.

4.3 GUARANTEE PROVISIONS

The Guarantees set forth herein are subject to the following provisions:

1. The equipment shall be operated and maintained according to Seller's O&M Manual prior to testing.
2. Process operating conditions must remain as set forth in the Design Specifications
3 The customer shall cooperate with and assist Seller in making any corrections or adjustments which may be necessary in order to meet the warranty.
4. All replacement parts shall be of Seller's manufacture or supply.
5. Emission testing is to be performed by others per the above agreed upon method within 24 months after successful installation and witnessed at the option of Seller. Seller shall be given at least two (2) weeks notice prior to testing.
6. Within five (5) days before the outlet emission performance test date, the equipment shall be operated for a period of no less than seventy-two (72) continuous hours at the specified design operating conditions at constant temperature.

7. All auxiliary emission control equipment must be maintained in proper operating condition in accordance with the manufacturer's O&M manual.

4.4 EQUIPMENT REMEDY

If prior to the expiration of the Guarantee Period set forth herein, Seller received written notice from the Owner that the equipment fails to meet the above Performance Guarantee (as determined by results of the Field Performance Testing Methods stated herein), Seller agrees to provide all necessary material in accordance with the Ex-Works terms of the contract for modifications or corrections to the equipment in order to meet the Performance Guarantees.

THE PERFORMANCE GUARANTEES SET FORTH IN THIS SECTION ARE THE SOLE PERFORMANCE GUARANTEES MADE BY THE CONTRACTOR WITH RESPECT TO THE EQUIPMENT AND NO OTHER WARRANTIES OR GUARANTEES OF PERFORMANCE, WHETHER STATUTORY, WRITTEN, ORAL, EXPRESSED OR IMPLIED BY LAW SHALL APPLY. THE OWNER'S EXCLUSIVE REMEDY AND THE CONTRACTOR'S SOLE OBLIGATION FOR FAILURE TO MEET THE PERFORMANCE GUARANTEES SHALL BE THOSE STATED IN THIS SECTION.

4.5 WARRANTY

A. Seller warrants that the Equipment described herein when shipped is free from defects in materials and in Seller's workmanship and design. If any such defect exists or later appears, Seller shall undertake, at its sole expense, prompt remedial action as stated herein to correct the same, provided, however, that Seller shall have no obligation or liability under this Warranty unless it shall have received written notice specifying such defect no later than twelve (12) months from the completion of start-up or eighteen (18) months from the date of substantial shipment of the Equipment by the Seller, whichever occurs first.

B. Remedial action under this Warranty shall require only that Seller, at its option, repair or modify the part or replace the same Ex-Works shipping point.

C. On an equipment supply only contract, Owner shall be responsible for field labor and all in and out costs on warranty repairs or replacements.

D. This warranty is subject to the following conditions: (a) Seller's instructions as to handling, installation, operation and maintenance have been followed; (b) the

Equipment and associated equipment have been used under normal operating conditions; (c) the Equipment has been properly operated and maintained and has not been affected by misuse, neglect or accident; (d) Owner has not attempted or performed corrective work without Seller's prior written consent and (e) Contractor shall have received written notice of any defect no later than ten (10) days after Owner first has knowledge of same. The above Warranty does not cover, and Seller makes no warranty which extends to, damage to the Equipment due to deterioration or wear occasioned by abrasion, corrosion, or erosions.

E. THIS WARRANTY IS IN SUBSTITUTION FOR, AND IN LIEU OF, ANY AND ALL OTHER WARRANTIES, EXPRESS, IMPLIED OR STATUTORY, INCLUDING WARRANTIES OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE.

F. Remedial action in the manner and within the period of time specified above shall constitute fulfillment of all liabilities from Seller to Owner and Owner's sole remedy hereunder whether based on contract, warranty, negligence or otherwise.

Limitation of Liability

In no event shall the total liability of the Seller arising out of the performance or breach of this Purchase Order, whether based on contract, warranty, negligence, indemnity, strict liability or otherwise, exceed the Purchase Order price.

The Seller shall in no event be liable for any consequential, incidental, indirect, special, or punitive damages arising out of this Purchase Order or any breach thereof, or any defect in the Equipment purchased hereunder, including, but not limited to, lost profits or revenue, work stoppage, impairment of other goods, loss by reason of shutdown or non-operation or increased expenses of operation, whether or not such loss or damage is based on contract, warranty, negligence, indemnity, strict liability or otherwise.

Indemnity

Seller hereby releases and will indemnify, defend and hold harmless Owner from and against any and all claims, suits, demands, liability, losses, damages or expenses, including reasonable attorney's fees, of any kind or nature whatsoever, to the extent any such claims, suits, demands, liability, losses, damages or expenses, including reasonable attorney's fees are: (1) the direct result of a negligent act or omission of Seller, its subcontractors or other third parties under Seller's reasonable direction and control; and (2) are attributable to bodily injury, sickness, disease or death, or to injury to or destruction of tangible property. Seller shall not be required to indemnify Owner to the extent that any claim, suit, demand, liability, loss or damage arises out of or results from the acts or omission of Purchaser, or any third party under the reasonable direction and control of Owner.

SECTION 5 - COMMERCIAL INFORMATION

5.1 BUDGET PRICING

Amerair Industries will design, fabricate, and supply the Sodium Bicarbonate Injection System and all associated equipment that has been described herein – excluding listed options, FOB SHOP for the Price of:

Two Million, Eight Hundred Thousand
U.S. Dollars and 00/100 cents. . . . . $ 2,800,000

5.2 OPTIONS

Amerair will provide a field erection advisor per Section 3, Article QQ
for a price adder of : . . . . **$ 26,732**

Amerair will provide start up assistance per Section 3, Article QQ of this proposal
for a price adder of: . . . . **$ 39,685 ***

Note: Services quoted are in excess of those specified due to added requirements for specialized equipment such as mills and feeders.

5.2.1 VALIDITY AND ESCALATION

Pricing stated in Articles 5.1 and 5.2 are valid for 60 days from January 20, 2017 but subject to escalation in accordance with:

Due to current volatility in the steel market, material escalation (if any) will be based on AMM (American Metals Market) published price index for hot rolled carbon steel and on the North American Stainless published priced index stainless steel. Pricing included in this proposal is based on today's published index. Any increase in steel costs between date of proposal and material procurement above this benchmark will be to customer's account. (Example: If steel increases $.03/per pound, this would increase the cost of a 30,000 lb. tank as follows: 30,000 lbs. x 3¢ = $900). (Note: Steel is typically procured anywhere from 2 weeks after returned approval drawings to approx. 6 weeks prior to shipment).

5.3 PROPOSED TERMS OF PAYMENT (TO BE NEGOTIATED)

All payments shall be made by Purchaser to Amerair Industries, LLC, Post Office Box 2705, Woodstock, GA 30188 according to the following progress billing schedule:

- **10%** of the total contract price due upon written Purchase Order.
- **10%** of the total contract price due upon submittal of approval drawings including GA's, structural loads, and P&ID's.
- **30%** of the total contract price due upon receipt of major plate steel at plate fabricator's shop.
- **45%** of the total contract price due upon delivery of baghouse modules and manifolds at site.
- **5%** retainage final payment due upon completion of startup, but not to exceed 60 days after delivery of baghouse modules.

- ➢ All payments are due net 30 days.
- ➢ Taxes and duties are not included.
- ➢ Pricing is valid for 45 days from date of proposal

Taxes, tariffs, and duties, if applicable, are not included. AMERAIR INDUSTRIES can supply additional field services upon request under the following conditions and rates:

1. All travel and living expenses to be invoiced at the incurred cost. Travel time portal to portal will be invoiced at normal rate.
2. a) For normal work hours between 8:00 a.m. and 5:00 p.m., Monday through Friday, the hourly rate is $ 125.00/hour or $ 1,000.00/8 hour day.
   b) For overtime hours, not including Sundays and holidays, the hourly rate is $187.50/hour or $ 1,500.00/8 hour day.
   c) For hours of work on Sundays and holidays the hourly rate is $250.00/hour or $2,000.00/8 hour day.

5.4 TERMS AND CONDITIONS

Amerair has reviewed the contract documents and has submitted "red line" changes within the document file.

5.5 PRELIMINARY SCHEDULE

To be Determined but delivery will be accomplished within the necessary time for project completion.

SECTION 6 - EXCEPTIONS & CLARIFICATIONS

Section	Exception/Clarification

Supply, specifications, and scope are limited to those given in all Sections and Articles of this Proposal.

Implementation of BACT as described and detailed in this Analysis will result in the following net reductions in potential emissions from the significant units at Doyon Utilities, LLC (DU) and U.S. Army Garrison Fort Wainwright (FWA), as outlined below:

Potential to Emit

Source	NO_x (tpy)		SO_2 (tpy)		$PM_{2.5}$ (tpy)	
	Baseline	**Proposed**	**Baseline**	**Proposed**	**Baseline**	**Proposed**
Doyon Utilities, LLC						
DU-1 through DU-6	1478	990	1,764	1050	131	69
Emergency Engines, Generators, and Pumps[1]	54	32	2.8	0.22	2.63	1.7
Coal Prep 7a-7c					0.34	0.05
Ash Handling 51a-51b	0	0.00	0.00	0.00	2.83	0.42
Coal Pile					3.22	3.22
Facility Total	1533	1022	1767	1050	140	71
Fort Wainwright Garrison						
Fuel Oil Boilers	2.5	2.5	7.3	7.5	0.1	0.1
Emergency Engines, Generators, and Pumps	25.4	25.4	4.9	4.9	1.2	1.2
Waste Oil Boiler	0.42	0.42	6.44	6.44	<0.01	<0.01
Facility Total	28.25	28.25	19	19	1.33	1.33
TOTAL	1561	1051	1786	1069	142	73
Reduction (tpy)	510		717		69	
% Reduction	33%		40%		49%	

tpy = tons per year

[1]Although included in this grouping, EU8 at DU is allowed to transition to a non-emergency engine once requirements under 40 Code of Federal Regulations (CFR) Part 63 Subpart ZZZZ are achieved. The engine's potential to emit (PTE) is still limited to 500 hours per year.

$PM_{2.5}$ in table above for the Fort Wainwright Garrison sources is equal to the potential particulate matter with a diameter less than or equal to 10 microns (PM_{10}) as the Fort did not provide $PM_{2.5}$ values separately.

9.0 CONCLUSION

Based on the BACT Analysis, the following BACT devices or operational limits should be considered as meeting the EPA methodology for choosing BACT.

Summary Table of BACT

Pollutant	Proposed BACT Emission Limitation	BACT Device(s) or Operational Limitation(s)
Coal Fired Boilers - 230 MMBTU/hr, DU-1 through DU-6 ***Coal combustion limited to 300,000 ton/year, 12 month rolling totals***		
• NO_x • SO_2 • $PM_{2.5}$	• 6.6 lb/ton coal combusted • 0.2% sulfur by weight in fuel, 12-month weighted average • 0.46 lb $PM_{2.5}$/ton coal combusted	• Good Combustion Practices • Good Combustion Practices • Full Stream Baghouse
Emergency Engines, Generators, and Fire Pumps		
• NO_x • SO_2 • $PM_{2.5}$	• Operations of certified engines and good combustion practices • Good combustion practices and combustion of ULSD • Good combustion practices and combustion of ULSD	
Fuel Oil Boilers		
• NO_x • SO_2 • $PM_{2.5}$	• Good combustion practices • Good combustion practices and combustion of ULSD • Good combustion practices	
Material Handling Sources (Coal Prep and Ash Handling)		
• $PM_{2.5}$ • $PM_{2.5}$	• Enclosed emission points and follow manufacturer recommendations for operations and maintenance	

By implementing the BACT devices and operational limits presented above, the Fort Wainwright Installation, a combination of EUs owned and operated by DU and FWA, should meet the following reductions presented below.

Proposed BACT Emission Reductions

Source	NO_x (tpy)		SO_2 (tpy)		$PM_{2.5}$ (tpy)	
	Baseline	**Selected**	**Baseline**	**Selected**	**Baseline**	**Selected**
Doyon Utilities, LLC						
DU-1 through DU-6	1,478	990	1,764	1,050	131	69
Emergency Engines, Generators, and Pumps	54	32	2.8	0.22	2.6	1.7
Material Handling Equipment	0	0.00	0.00	0.00	4	5
Facility Total	1,533	1,022	1,767	1,050	143	74
Fort Wainwright Garrison						
Fuel Oil Boilers	2.5	2.5	7.3	7.5	0.1	0.1
Emergency Engines, Generators, and Pumps	25.4	25.4	4.9	4.9	1.2	1.2
Waste Oil Boiler	0.42	0.42	6.44	6.44	<0.01	<0.01
Facility Total	28.19	28.19	9	19	1.33	1.33
TOTAL	1,561	1,051	1,786	1,069	142	73
Reduction (tpy)	510		717		69	
% Reduction	33%		40%		49%	

DEPARTMENT OF THE ARMY
INSTALLATION MANAGEMENT COMMAND
HEADQUARTERS, U.S. ARMY GARRISON, FORT WAINWRIGHT
1046 MARKS ROAD
FORT WAINWRIGHT, ALASKA 99703

JUL 10 2017

Directorate of Public Works

Division of Air Quality
Alaska Department of Environmental Conservation
410 Willoughby Avenue, Ste 303
PO Box 111800
Juneau, Alaska 99801

Dear Ms. Koch:

The enclosed report provides the Best Available Control Technology analysis requested by the Alaska Department of Environmental Conservation, Division of Air Quality in April 2015. Copies of the request are incorporated into the Appendix A of the enclosed report.

The emission units addressed by the analysis encompass air quality operating permits #AQ0236TVP03 (Fort Wainwright) and #AQ112TVP02 (Doyon Utilities). As noted in the statement of basis of each permit, the two permits constitute a single major stationary source.

Questions or concerns regarding this notification may be directed to Eric Dick, Directorate of Public Works, Environmental Division, Air Quality Program Manager at (907) 361-3006 or eric.m.dick2.civ@mail.mil.

Sincerely,

Sean C. Williams
Colonel, US Army
Commanding

Enclosure

THE STATE of ALASKA
GOVERNOR BILL WALKER

Department of Environmental Conservation

DIVISION OF AIR QUALITY
Director's Office

410 Willoughby Avenue, Suite 303
PO Box 111800
Juneau, Alaska 99811-1800
Main: 907-465-5105
Toll Free: 866-241-2805
Fax: 907-465-5129
www.dec.alaska.gov

CERTIFIED MAIL: 7016 3010 0000 0426 8398
Return Receipt Requested

October 20, 2017

Rich Morris
Directorate of Public Works-Environmental Division
U.S. Army Fort Wainwright
Attn. Richard Morris-Building 3023
1046 Marks Rd
Fort Wainwright, AK 99703

Subject: Request for additional information for the Best Available Control Technology Technical Memorandum for Fort Wainwright by December 22, 2017

Dear Mr. Morris:

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

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

[1] Federal Register, Vol. 82, No. 89, Wednesday May 10, 2017 (https://dec.alaska.gov/air/anpms/comm/docs/2017-09391-CFR.pdf)
[2] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf, Clean Air Act 189 (b)(1)(B) and 189 (e) and CFR 51.1010(4)(i) require the implementation of BACT for point sources and precursors emissions and BACM for area sources.
[3] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf, Clean Air Act 189 (b)(1)(B) and 189 (e) require the implementation of BACT for point sources and precursors emissions and BACM for area sources

Clean Air

to Mr. Eric Dick at Fort Wainwright on May 11, 2017 notifying him of the reclassification to Serious and included a request for the BACT analysis to be completed by August 8, 2017. The BACT analysis from Fort Wainwright, which included emission units found in Operating Permits AQ1121TVP02 Revision 2 and AQ0236TVP03 Revision 2, was submitted by email to the Department on July 13, 2017.

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

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

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

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

Sincerely,

Denise Koch

Denise Koch, Director
Division of Air Quality

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[4] https://www.gpo.gov/fdsys/pkg/USCODE-2013-title42/html/USCODE-2013-title42-chap85-subchapI-partD-subpart4-sec7513a

[5] 40. CFR 51.1010(4)

Enclosures:

October 20, 2017	Request for Additional Information for Fort Wainwright BACT Analysis;
May 11, 2017	Serious SIP BACT due date email
April 24, 2015	Voluntary BACT Analysis for Fort Wainwright (Privatized Emission Units) to Eric Dick, Environmental Manager US Army Fort Wainwright
April 24, 2015	Voluntary BACT Analysis for Fort Wainwright (Privatized Emission Units) to Kathleen Hook, Environmental Program Manager, Doyon Utilities, LLC

cc: Larry Hartig, ADEC/ Commissioner's Office
Alice Edwards, ADEC/ Commissioner's Office
Cindy Heil, ADEC/Air Quality
Deanna Huff, ADEC/ Air Quality
Jim Plosay, ADEC/ Air Quality
Aaron Simpson, ADEC/Air Quality
Eric Dick/U.S. Army (Fort Wainwright)
Tim Hamlin, EPA Region 10
Zach Hedgpeth, EPA Region 10

ADEC Request for Additional Information
Fort Wainwright – Doyon Utilities
BACT Analysis Review
HydroGeoLogic, Inc. Report, June 2017

October 20, 2017

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

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

Draft Comments

1. Equipment Life – Page 4-2 of the analysis states "The BACT analysis for all control technologies assumes a 10-year useful life." ADEC identified that the EPA Air Pollution Control Cost Manual[1] (cost manual) uses a hypothetical example that assumes the control equipment has a useful life of ten years. However the cost analysis must use a reasonable estimate of the actual life of the control equipment for each control technology. As indicated in the proposed rule for Texas and Oklahoma Federal Implementation Plan for Regional Haze and Interstate Transport of Pollution Affecting Visibility – EPA-R06-OAR-2014-0754; Federal Register, Vol. 79, No. 241, 74818 [2] EPA indicated that:

    > "In determining the cost of scrubbers in our prior Oklahoma FIP, we used a lifetime of 30 years. In so doing, we noted that scrubber vendors indicate that the lifetime of a scrubber is equal to the lifetime of the boiler, which might easily be over 60 years. We also noted that many scrubbers that were installed between 1975 and 1986 are still in operation today (e.g., Coyote Station, H.L. Spurlock Unit 2, East Bend Unit 2, Laramie River Unit 3, Cholla 5, Basin Electric, Mitchell Unit 33, and all of the units in Table 30 that currently have scrubbers). Further, we noted that standard cost estimating handbooks and published papers report 30 years as a typical life for a scrubber and that many utilities routinely specify 30+ year lifetimes in requests for proposal and to evaluate proposals."

    In order to use an equipment life that is shorter than 30 years evidence must be provided to support the claim that "DU [Central Heat and Power Plant] is nearing the end of the useful design life cycle." This evidence could include information regarding the actual age of currently

[1] U.S. EPA OAQPS Air Pollution Control Cost Manual, 6th Edition [EPA/452/B-02-001]
[2] https://www.regulations.gov/document?D=EPA-R06-OAR-2014-0754-0001

operating control equipment, or design documents for associated process equipment such as boilers.

2. DSI Cost Analysis – The cost manual does not currently include a chapter covering dry sorbent injection (DSI). However, as part of their Regional Haze FIP for Texas, EPA Region 6 developed cost estimates for DSI as applied to a large number of coal fired utility boilers. See the Technical Support Documents for the Cost of Controls Calculations for the Texas Regional Haze Federal Implementation Plan (Cost TSD) for additional information. The Cost TSD and associated spreadsheets are located at: https://www.regulations.gov/document?D=EPA-R06-OAR-2014-0754-0008. Please update the cost analysis for DSI and provide technical justifications for all assumptions used in the analysis submitted as part of the BACT analysis (i.e., direct and indirect contingency costs, startup costs, initial performance test costs, electricity rate, and reagent costs). Additionally, see Comments 7, 11, and 12 for additional information related to retrofit costs, baseline emissions, and factor of safety.

3. SNCR Cost Analysis – The EPA has recently updated the cost manual chapter pertaining to SNCR, and developed a cost spreadsheet to be used for evaluation of this technology for cost effectiveness. The cost analysis submitted as part of this BACT analysis[3] uses the EPA cost spreadsheet. Please update the cost analysis using the unrestricted potential to emit for each of the emissions units or propose operational limits (i.e., 300,000 tons of coal per year). Additionally, see Comments 7, 11, and 12 for additional information related to retrofit costs, baseline emissions, and factor of safety.

4. SCR Cost Analysis – The EPA has recently updated the cost manual chapter pertaining to SCR, and developed a cost spreadsheet to be used for evaluation of this technology for cost effectiveness. The cost analysis submitted as part of this BACT analysis[4] uses the EPA cost spreadsheet. Please update the cost analysis using the unrestricted potential to emit for each of the emissions units or propose operational limits. Additionally, see Comments 7, 11, and 12 for additional information related to retrofit costs, baseline emissions, and factor of safety.

5. BACT limits – BACT limits by definition, are numerical emission limits. However regulation allows a design, equipment, or work/operational practices if technological or economic limitations make a measurement methodology infeasible. Provide numerical emission limits (and averaging periods) for each proposed BACT selection, or justify why a measurement methodology is technically infeasible and provide the proposed design equipment, or work/operational practices for pollutant for each emission unit included in the analysis. Startup, Shutdown, and Malfunction (SSM) must be addressed in the BACT analysis. Measures to minimize the occurrence of these periods, or to minimize emissions during these periods are control options. Combinations of steady-state control options and SSM control options can be combined to create distinct control strategies. In no event shall application of BACT result in emissions of any pollutant which would exceed the emissions allowed by an applicable standard under 40 C.F.R. parts 60 (NSPS) and 61 (NESHAP).

6. Good Combustion Practices –For each emission unit type (coal boilers, distillate boilers, engines, and material handling) for which good combustion practices was proposed as BACT, describe what constitutes good combustion practices. Include any work or operational practices that will be implemented and describe how continuous compliance with good combustion practices will be achieved.

[3] "sncr_cost_manual_spreadsheet_2016_vf Ft Wainwright.xlsm"
[4] "scr_cost_manual_spreadsheet_2016_vf Ft Wainwright.xlsm"

7. Retrofit Costs – EPA's Control Cost Manual indicates that study-level cost estimates (± 30 percent) should not include a retrofit factor greater than 30 percent, so detailed cost estimates (± 5 percent) is required for higher factors. High retrofit cost factors (50 percent or more) may be justified in unusual circumstances (e.g., long and unique ductwork and piping, site preparation, tight fits, helicopter or crane installation, additional engineering, and asbestos abatement). Provide detailed cost analyses and justification for difficult retrofit (1.6 – 1.9 times the capital costs) considerations used in the BACT analysis.
8. Provide an economic analysis for low-NOx burners (LNBs) and flue gas recirculation (FGR) for one of the diesel-fired boilers, not proposed as limited operation (FWA EUs 8 – 10). Identify all small boilers with emission unit identification numbers. Provide in the analysis: the control efficiency associated with LNBs and FGR, Captured Emissions (tons per year), Emissions Reduction (tons per year), Capital Costs (2017 dollars), Operating Costs (dollars per year), Annualized Costs (dollars per year), and Cost Effectiveness (dollars per ton) using EPA's cost manual.
9. Identify the control efficiencies proposed for limited operation of the small diesel-fired boilers (FWA EUs 8 – 10). If limited operation is not selected for the 24 other small boilers (list EU ID numbers), identify the energy, environmental, economic impacts and other costs used to remove limited operation from the analysis. Include numerical NOx emission limits, work, or operational practices that will be implemented for the small boilers and describe how continuous compliance with the BACT limits will be achieved.
10. Identify control efficiencies for limited operation and installation of turbochargers and aftercoolers for diesel-fired engines to be used to rank the technically feasible control technologies. If the proposed control efficiencies of limited operation or installation of turbochargers and aftercoolers is greater than that of SCR, rank the control technologies to remove SCR from the top-down BACT analysis. If SCR is ranked as a higher control efficiency for reduction of NOx, provide justification as to why SCR can be removed from the analysis. If the engines only operate infrequently, as indicated in the analysis, provide a justification for why limited operation cannot be proposed as an enforceable limit, or provide an economic analysis that indicates that the cost effectiveness of installing SCR or turbochargers and aftercoolers would have an adverse economic impact. Identify how many hours the units would have to operate for SCR to become economically feasible for these units.
11. Include the baseline emissions for all emission units included in the analysis. Typically, the baseline emission rate represents a realistic scenario of upper bound uncontrolled emissions for the emissions unit (unrestricted potential to emit not actual emissions). NSPS and NESHAP requirements are not considered in calculating the baseline emissions. The baseline is usually the legal limit that would exist, but for the BACT determination. Baseline takes into account the effect of equipment that is part of the design of the unit (e.g., water injection and LNBs) because they are considered integral components to the unit's design. If the uncontrolled emission rate is 'soft,' run the cost effectiveness calculations using two or three different baselines.
12. If warranted, include a factor of safety when setting BACT emission limitations. The safety factor is a legitimate method of deriving a specific emission limitation that may not be exceeded. These limits do not have to reflect the highest possible control efficiencies, but rather, should allow the Permittee to achieve compliance with the numerical emission limit on a consistent basis.

13. Please propose numerical emission limits for the diesel-fired engines DU EUs 8 through 28, 30, 32 through 36, 29a, and 31a and FWA EUs 11, 12, 13, and 26 – 39. Provide the source of the emission factor (e.g., vendor data, AP-42 emission factor, EPA Tier Certified Engine, or NSPS Subpart IIII). Please identify what constitutes "good housekeeping practices" for DU EU 15 and describe how continuous compliance with these practices is BACT for the unit.
14. Include scrubbers and limited operation in the review of PM-2.5 control technologies for diesel-fired boilers. Rank the control technologies by efficiency (specify % control). Select the best performing control technology as BACT or provide specific energy, environmental, and economic impacts and other costs justification for why each better performing control technology was not selected instead of good combustion practices. Provide a numerical PM-2.5 emission limit for the diesel-fired boilers or identify the work or operational practices that will be utilized to ensure compliance with proposed limits.
15. Include positive crankcase ventilation (closed crank ventilation system) and limited operation in the review of PM-2.5 control technologies for engines. Rank the control technologies (include low ash fuel) by efficiency (specify % control). Select the best performing control technology as BACT or provide specific energy, environmental, and economic impacts and other costs justification for why each better performing control technology was not selected instead of combustion of ULSD (low ash fuel). Revise the economic analysis for PM-2.5 emission controls for engines to reflect a calculation based on the units' potential to emit, not 500 hours per year (i.e., 8,760 hours per year or enforceable permit limits). Provide numerical PM-2.5 emission limits for the engines or identify the work or operational practices that will be utilized as BACT for the diesel-fired engines.
16. Provide an analysis of why enclosures are not technically feasible for the coal pile storage. Covering a stockpile is a proven control method used in pulverized mineral processing operations. Additionally, provide an analysis of why wetting agents and watering for dust suppression is not considered technically feasible during the summer months (i.e., when the ambient temperature is above freezing). Provide a numerical PM-2.5 emission limit for the Emergency Coal Storage Pile and Operations or identify the work or operational practices that will be utilized as BACT for the material handling operations.

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May 23, 2018

Mr. Aaron Simpson
Alaska Department of Environmental Conservation
Division of Air Quality
P.O Box 111800
Juneau AK 99811-1800

Re: Comments Addressing the Preliminary Best Available Control Technology Determination for Fort Wainwright US Army Garrison and Doyon Utilities

Dear Mr. Simpson:

Doyon Utilities, LLC (DU) is providing the enclosed comments addressing the preliminary Best Available Control Technology (BACT) assessment that the Alaska Department of Environmental Conservation (ADEC) has prepared for the Fort Wainwright US Army Garrison and Doyon Utilities. DU has limited this review and comment effort to those emissions units that are operated by DU and that are included in Title V Permit AQ1121TVP02, Revision 2. DU has not provided comments addressing emissions units that are operated by the US Army Garrison.

DU appreciates this opportunity to provide comments addressing the preliminary BACT documents. DU understands that the preliminary BACT documents are a work in progress. DU also understands that ADEC hopes to receive additional information from the public as a result of the release of the preliminary draft BACT documents and that ADEC expects to make changes to the documents based upon this input.

The attached comments identify a number of concerns of varying degree of seriousness. The items discussed in the comments that are of most concern to DU are:

- The preliminary BACT analysis for sulfur dioxide (SO_2) emissions from the Central Heat and Power Plant (CHPP) boilers (Emissions Units (EUs) 1 through 6) identifies dry sorbent injection (DSI) as the preferred SO_2 emission control technology. The analysis that supports this determination is based on unsupported assumptions, use of a cost model that may not be appropriate for these boilers, and inconsistent SO_2 emission calculations. The analysis is also lacking site-specific engineering data. As a result, the analysis appears not to be defensible.
- The preliminary BACT analysis for SO_2 emissions from the CHPP boilers assumes a more stringent coal combustion limit and coal sulfur content than currently required, but does

not assess these options through the five-step BACT process or determine whether these assumptions are even valid.

- The preliminary $PM_{2.5}$ BACT analysis and draft BACT determinations for the material handling emissions units (EUs 7a, 7b, 7c, 51a, 51b, and 52) are confusing and unclear.
- The required methods to demonstrate compliance with the preliminary BACT limits are in many cases unclear or unspecified.
- Many of the preliminary $PM_{2.5}$ BACT emission limits are provided without supporting rationale, may not be appropriate as $PM_{2.5}$ emission limits, and/or may not be achievable.

Please contact Kathleen Hook at 907-455-1540 or khook@doyonutilities.com if you have any questions or would like to further discuss any specific comments.

Best Regards,

Shayne Coiley
Senior Vice President
Doyon Utilities, LLC

cc: Jim Plosay, ADEC
Kathleen Hook, DU
Courtney Kimball, SLR

Enclosure: Comments Addressing the Preliminary Best Available Control Technology Determination for Fort Wainwright US Army Garrison and Doyon Utilities Dated March 22, 2018

CO 18-061

Comments Addressing the Preliminary Best Available Control Technology Determination for Fort Wainwright US Army Garrison and Doyon Utilities Dated March 22, 2018

General Comments

1. Inadequate technical information is provided in the Preliminary Best Available Control Technology Determination (Preliminary Determination). This lack of information generally includes, but is not limited to, the following areas.
   - Little or no engineering data or rationale is provided to support the Alaska Department of Environmental Conservation (ADEC) preliminary determinations addressing whether an emission control technology is or is not technically feasible.
   - Little or no engineering data, cost data, or rationale is provided to support the preliminary determinations addressing whether an emission control technology is or is not Best Available Control Technology (BACT).
   - The methodology used to determine emissions reductions is typically not quantified.

   This lack of data and rationale is inconsistent with past ADEC insistence that the stationary sources provide a substantial level of detail and specific engineering data to support the BACT analyses that the stationary sources submitted to ADEC.

2. The Preliminary Determination tables that provide a comparison of emissions unit capacities and BACT emission limits for affected stationary sources (University of Alaska Fairbanks, Fort Wainwright, Golden Valley Electric Association (GVEA) North Pole Plant, and GVEA Zehnder Plant) generally have inconsistent units of measurement within each table. As a result, these tables have limited usefulness without further analysis being prepared.

3. In many cases, the Preliminary Determination does not identify the methods that must be used to verify compliance with the preliminary BACT limits. The methods to be used for verifying compliance should be identified so that the Permittees can determine whether the methods that ADEC intends to require are appropriate and whether the methods will be overly cumbersome and/or expensive.

Section 3. BACT Determination for Nitrogen Oxides (NO_X)

In Section 3 of the Preliminary Determination, ADEC states that "the NO_X controls proposed in this section are not planned to be implemented." Instead, ADEC is planning to submit a final precursor demonstration to the U.S. Environmental Protection Agency (EPA) "as justification not to require NO_X controls." As a result, Doyon Utilities (DU) has not reviewed this section of the Preliminary Determination and is not providing comments because:

- ADEC does not plan to implement the proposed NO_X BACT determinations, and
- Focusing on those sections of the Preliminary Determination that ADEC intends to implement is a better use of the short amount of time that was made available for this review.

DU will review any future NO_X BACT proposals and will provide comments if EPA does not approve the ADEC final precursor demonstration and the implementation of NO_X BACT emissions controls becomes mandatory.

Section 4. BACT Determination for Fine Fraction Respirable Particulate Matter ($PM_{2.5}$)

The ADEC preliminary $PM_{2.5}$ BACT analysis includes errors, assumptions, and inconsistencies that are of varying degree of concern. Each instance of concern is discussed below in no particular order of seriousness.

4. Section 4: The term "full steam baghouse" appears several times in the Preliminary Determination. The correct term is "full stream baghouse."

5. Section 4.1 (Industrial Coal-fired Boilers), Steps 4(b) and 5(b): The Preliminary Determination establishes a $PM_{2.5}$ emission limit of 0.05 grains per dry standard cubic foot (gr/dscf) for the coal-fired boilers, Emissions Units (EUs) 1 through 6. No basis for the selection of this $PM_{2.5}$ emission rate is provided, but the selected emission rate value is consistent with the particulate matter (PM) emission rate for industrial processes and fuel burning equipment established in 18 Alaska Administrative Code (AAC) 50.055(b)(1). This PM emission limit is commonly called the SIP PM emission limit. The appropriateness of using the SIP PM emission limit to establish a $PM_{2.5}$ emission limit is unclear because:
   - PM includes all filterable particulate matter regardless of size while $PM_{2.5}$ includes only filterable particulate matter with an nominal aerodynamic diameter of 2.5 microns, and
   - $PM_{2.5}$ includes all condensable matter while PM does not include any condensable matter.

   In many, but not all cases, actual PM emissions from a fuel-fired emissions unit are greater than the actual $PM_{2.5}$ emissions from that same emissions unit. If the assumption is being made that $PM_{2.5}$ emissions from EUs 1 through 6 are less than or equal to PM emissions, this assumption should be supported with existing source test results to confirm that compliance with the preliminary limit can be met. If this assumption is not being made, ADEC should explain more fully the rationale for selecting a $PM_{2.5}$ emission rate of 0.05 gr/dscf as the $PM_{2.5}$ BACT emission limit for EUs 1 through 6.

6. Section 4.1 (Industrial Coal-fired Boilers), Table 4-2: This table provides the total plant capacity for the listed stationary sources instead of individual boiler capacity. The preliminary $PM_{2.5}$ BACT emission limits are not presented in consistent units of measurement or are not provided in the table. As a result, the table is not useful for the intended comparative purpose.

7. Section 4.3 (Large Diesel-fired Engines), Step 1(f): This section cites "RBLC NO_X determinations." The correct reference is "RBLC information for $PM_{2.5}$ determinations."

8. Section 4.3 (Large Diesel-fired Engines), Steps 1 through 5: The ADEC rationale for the preliminary BACT determination of combusting ultra-low sulfur diesel (ULSD) is inconsistent for the following reasons.

- In Step 1(d), the use of low sulfur fuel is listed as an available and feasible emission control technology.
- Step 2 eliminates low sulfur fuel as technically infeasible which is inconsistent with the statement in Step 1 and incorrect. The use of low sulfur fuel is technically feasible, but the contribution of this technology toward reducing $PM_{2.5}$ emissions cannot be quantified.
- Step 3 does not address the use of ULSD.
- Step 5 requires the use of ULSD, with no supporting rationale or cost analysis. This determination is also inconsistent with the incorrect Step 2 conclusion that low sulfur fuel is not technically feasible.

Please make the appropriate corrections to Section 4.3. DU understands that the requirement to combust ULSD will likely remain unchanged for the large diesel-fired engines. Specifically, the preliminary sulfur dioxide (SO_2) BACT decision also requires the use of ULSD, so correcting this inconsistency in Section 4.3 will not eliminate the requirement to combust ULSD in the large diesel-fired engines. The combustion of ULSD is required in the large diesel-fired engines that are subject to 40 Code of Federal Regulations (CFR) 60 Subpart IIII.

9. Section 4.3 (Large Diesel-fired Engines), Step 4 and 5: A cost analysis is not provided to support the preliminary $PM_{2.5}$ BACT determinations identified in Step 5. Because each BACT determination must be based on technical and economic feasibility, the rationale for these preliminary determinations is incomplete, making the validity of the preliminary determinations questionable. Please provide the required economic feasibility analysis.

10. Section 4.3 (Large Diesel-fired Engines), Step 5(b): The Preliminary Determination is unclear with respect to whether the 500 hours per year operating limit in non-emergency situations is applicable to EUs 8, 10, 11, 13, and 15 individually or cumulatively. If the operating limit is cumulative, the limit is inconsistent with Title V Permit AQ1121TVP02 which allows EU 8 to be converted to a non-emergency engine with a limit of 500 hours per year. If the limit applies to each individual engine, the requirement is inconsistent with applicable requirements under 40 CFR 63 Subpart ZZZZ (or Subpart IIII, if applicable), which allows 100 hours per year of non-emergency operation but does not restrict those non-emergency operations to maintenance checks and readiness testing.

11. Section 4.3 (Large Diesel-fired Engines), Table 4-6: This table cites manufacturer information for establishing the preliminary $PM_{2.5}$ BACT limit of 0.09 grams per horsepower-hour (g/hp-hr) for EU 15. The source of this manufacturer information is not provided in the Preliminary Determination and cannot otherwise be obtained to confirm this $PM_{2.5}$ emission rate is correct. An emission rate of 0.09 g/hp-hr is equivalent to 0.0002 pounds per horsepower-hour (lb/hp-hr). Potential emissions of $PM_{2.5}$ for EU 15 are currently calculated using an emission factor of 0.0007 lb/hp-hr per AP-42, Table 3.4-1. As a result, the preliminary BACT $PM_{2.5}$ limit of 0.09 g/hp-hr may not be appropriate or achievable for EU 15. Please provide the manufacturer information stating that a $PM_{2.5}$ emission rate of 0.09 g/hp-hr has been established for EU 15.

12. Section 4.4 (Small Emergency Engines), Step 5(a): The requirement to limit non-emergency operation of each of EUs 9, 12, 14, 16 through 28, 29a, 30, 31a, and 32 through 36 to 500 hours per year is

inconsistent with applicable requirements under 40 CFR 63 Subpart ZZZZ (or Subpart IIII, if applicable), which allows 100 hours per year of non-emergency operation but does not restrict those non-emergency operations to maintenance checks and readiness testing.

13. Section 4.4 (Small Diesel-fired Engines), Steps 1 through 5: The ADEC rationale for the preliminary BACT determination of combusting ultra-low sulfur diesel (ULSD) is inconsistent for the following reasons.
    - In Step 1(d), the use of low sulfur fuel is listed as an available and technically feasible emission control technology.
    - Step 2 eliminates low sulfur fuel as technically infeasible which is inconsistent with the statement in Step 1 and incorrect. The use of low sulfur fuel is technically feasible, but the contribution of this technology toward reducing $PM_{2.5}$ emissions cannot be quantified.
    - Step 3 does not address the use of ULSD.
    - Step 5 requires the use of ULSD, with no supporting rationale or cost analysis. This determination is also inconsistent with the incorrect Step 2 conclusion that low sulfur fuel is not technically feasible.

    Please make the appropriate corrections to Section 4.4. DU understands that the requirement to combust ULSD will likely remain unchanged for the small diesel-fired engines. Specifically, the preliminary sulfur dioxide (SO_2) BACT decision also requires the use of ULSD, so correcting this inconsistency in Section 4.4 will not eliminate the requirement to combust ULSD in the small diesel-fired engines.

14. Section 4.4 (Small Diesel-fired Engines), Steps 4 and 5: A cost analysis is not provided to support the preliminary $PM_{2.5}$ BACT determinations identified in Step 5. Because each BACT determination must be based on technical and economic feasibility, the rationale for these preliminary determinations is incomplete, making the validity of the preliminary determinations questionable. Please provide the required economic feasibility.

15. Section 4.4 (Small Diesel-fired Engines), Table 4-9: The proposed preliminary $PM_{2.5}$ BACT limit of 7.21 E-04 pounds per horsepower-hour (lb/hp-hr) is the PM_{10} emission factor for gasoline-fired engines from Table 3.3-1 of AP-42. Using this emission factor is not appropriate for diesel-fired engines or for $PM_{2.5}$.

16. Section 4.5 (Material Handling): This section addresses the material handling emissions units (EUs 7a through 7c, 51a, 51b, and 52) but does not make a distinction between the material handling emissions units that can be equipped with fabric filter controls (EUs 7a through 7c, 51a, and 51b) and the emissions unit that cannot be equipped with a baghouse (EU 52, the emergency coal storage pile) Because a coal storage pile is a very different type of emissions unit, the section is not clear with respect to the types of emission control technologies that might be used for each listed emissions unit. As a result, EU 52 should be addressed separately for clarity.

    As an example of this confusion, Step 1(g) indicates that wind screens are not considered technically feasible for material handling units, but Step 2 states that all identified control technologies are technically feasible. Wind screens may be an available and/or technically feasible control technology for a coal storage pile, but not necessarily for a dust collector. Conversely, fabric filters are identified as available and technically feasible in Step 1(a), but fabric filters are not an available control technology for coal storage piles.

17. Section 4.5 (Material Handling), Table 4-12: The proposed preliminary $PM_{2.5}$ BACT for EU 7c, the North Coal Handling Dust Collector, includes a 200 hours per year (hr/yr) operating limit. This emissions unit is a backup coal handling system that is used if the primary system coal handling system is not available. The Preliminary Determination does not explain the basis for this BACT operating limit. Pleased fully explain the rationale for imposing a BACT operating limit of 200 hr/yr on EU 7c.

18. Section 4.5 (Material Handling), Steps 4(e) and 5(c): The preliminary proposed $PM_{2.5}$ BACT emission limit of 0.48 tons per year (tpy) for EU 52 is 34 percent of the existing $PM_{2.5}$ potential to emit of 1.42 tpy. The Preliminary Determination does not provide the basis for the 0.48 tpy $PM_{2.5}$ BACT emission limit or explain the emission limit calculation methodology. Please fully explain the basis and rationale for imposing a $PM_{2.5}$ BACT emission limit of 0.48 tpy on EU 52.

19. Section 4.5 (Material Handling), Table 4-12: This table includes columns labeled "Current Controls" and "Current Emission Factors." The table does not provide preliminary proposed $PM_{2.5}$ BACT emission limits, which is inconsistent with the Table 4-12 title of "PM-2.5 BACT Control Technologies Proposed for Material Handling."

Section 5. BACT Determination for SO_2

The Preliminary Determination SO_2 BACT analysis includes errors, assumptions, and inconsistencies that are of varying degree of concern. These concerns are discussed below in no particular order of seriousness.

20. Section 5.1 (Industrial Coal-fired Boilers): In Table 5.3, the Preliminary Determination specifies SO_2 cost effectiveness for wet scrubbing and spray dry absorbers to be $10,788 per ton SO_2 removed and $11,136 per ton SO_2 removed, respectively. Although not explicitly stated, the Preliminary Determination implies that these two technologies are not economically feasible and so are not SO_2 BACT. While the economically feasibility analyses for these two control technologies likely underestimate actual costs, DU agrees that wet scrubbing and spray dry absorbers are not SO_2 BACT. As a result, comments addressing wet scrubbing or spray dry absorbers are not presented in this document.

    The preliminary proposed SO_2 BACT is dry sorbent injection (DSI) which the Preliminary Determination states has a cost effectiveness of $6,435 per ton SO_2 removed. This cost effectiveness determination is questionable and likely too low for the reasons provided below. Note that developing an accurate cost effectiveness for DSI would require a bottom-up cost estimate based on actual plant conditions.

- Cost Model Validity: The cost effectiveness spreadsheet provided by ADEC as a part of the preliminary SO_2 BACT determination was originally developed by Sargent & Lundy (S&L) in 2010. The spreadsheet includes a link to the S&L white paper that provides a basis for the calculations that are in Row 25 of the spreadsheet. The S&L white paper states that the model is intended to calculate estimated Total Project Cost (total capital cost of installation), as well as direct and indirect annual operating costs. These calculations are largely based on the estimated usage of sorbent (in this case Trona) on a tons per hour (tph) basis and the gross generating capacity of the plant. The white paper omits information that is necessary to ensure that the spreadsheet is properly applied to a specific situation, including:
  - Types of plants to which the model is applicable (utility power generation, combined heat and power (CHP), cogeneration, other);
  - Applicable number of boilers (single unit or multi-boiler installation);
  - Applicable size range;
  - Equipment included in the Total Purchased Cost (TPC) calculation;
  - On-site bulk storage capacity;
  - A basis for selecting a "Retrofit factor" other than "1.0"; and
  - Data and other information used to develop and support the equations used in the spreadsheet.

  Based on review of the cost effectiveness model and the supporting documentation, determining the validity of the results of the analysis is not possible. The concerns are rooted in three assumptions made by ADEC in preparing the cost model
  - ADEC assumed that the model is valid for a plant the size of Fort Wainwright.
    - The calculation for "Base Module" cost (Row 30 of the spreadsheet) is based on an equation that uses the predicted sorbent demand. The S&L white paper states that the equation was developed based on "Cost data for several DSI systems." No references or supporting information relating to these projects were provided. While the validity range for the equation was not identified, one piece of information that gives some indication of the applicable range. The equation has a discontinuity at 25 tph of sorbent flow. Given that the predicted total sorbent flow for all six coal-fired boilers at Fort Wainwright is 1.5 tph (based on the estimate in the Preliminary Determination), the Fort Wainwright boilers would be at the very bottom of the range of potential plant sizes. Without additional data to justify the cost calculation at very low sorbent injection rates, determining if the results of the equation are accurate is very difficult.
  - The Preliminary Determination assumes that multiple boilers can accurately be modeled as a lumped heat input in a single spreadsheet.
    - The S&L white paper does not identify the type or configuration of the plant on which the calculation was based. Data input fields included in the spreadsheet (unit size, gross heat rate) indicate that the analysis was developed based on a single power generation unit (single boiler, single steam turbine, no CHP or cogeneration).
    - Based on the inputs to the spreadsheet provided by ADEC, EUs 1 thorough 6 are being treated as a single, lumped heat input value. This approach is an oversimplification and will not accurately account for the equipment and utilities that will be necessary to independently operate six boilers. The actual installation will require six separate trains of sorbent processing and transport equipment. Each train contains a day bin, mills,

feeders, blowers, coolers, hoppers, piping, instrumentation, controls, electrical wiring and other supporting equipment. This need for separate systems complicates the design, increases overall footprint, and reduces the economy of scale that might be realized with a single larger unit. In theory, ADEC could possibly use the Retrofit Factor to account for this additional complexity, but without a method for determining the correct Retrofit Factor value, selecting any value other than "1.0" would be pure conjecture.

    - The sorbent feed rate currently calculated for EUs 1 through 6 is very small. Should the model be revised to calculate the cost effectiveness on a per unit basis, the feed rate would be roughly one sixth of the current value. This change would further amplify concerns about the accuracy of the TPC calculation.

  - ADEC assumed that the model is valid for a heat and power plant.
    - As discussed above, no information is available addressing the type of plant on which the S&L spreadsheet is based. The assumption is that the plant is a single power generation unit. A CHP plant differs significantly from a "traditional" power plant in that the steam produced in a CHP plant is not exclusively used to generate electricity. In an effort to make the spreadsheet work for this application, ADEC used "dummy" data in the "Unit Size (Gross)" and "Gross Heat Rate" fields so that the calculated "Heat Input" field showed the maximum heat input value for EUs 1 through 6 (1,380 million British thermal units per hour (MMBtu/hr)). This approach has unintended consequences relating to the accuracy of the direct annual costs. The fixed and variable operating and maintenance (O&M) costs are evaluated on a per kilowatt and a per megawatt basis respectively. Utilizing a "dummy" gross generation number to calculate annual costs may not produce an accurate result. Based on review, no method exists to accurately model the direct annual costs for an installation such as the Fort Wainwright EUs 1 through 6 by using the S&L spreadsheet.
    - The average maximum hourly heat input identified in Row 15 of the spreadsheet is incorrect. The value shown reflects the maximum hourly heat input for each of the boiler. The value does not account for the permitted annual coal consumption limit. If the coal consumption limit is considered, the maximum hourly heat input is reduced to 583 MMBtu/hr averaged over a year. A reduction in hourly heat input will have an impact on the overall cost effectiveness calculation, but given the concerns with the calculation itself, identifying the specific impacts is difficult.

- SO_2 Emission Rates: The preliminary BACT determination states that the SO_2 emission rate used in the spreadsheet to calculate the total annualized operating costs was based on 0.2 weight percent (wt. pct.) sulfur coal and AP-42 emission factors. This approach resulted in an emission rate of 0.46 pounds of SO_2 per MMBtu (lb SO_2/MMBtu) heat input. This value is significantly different than the effective emission rate for the plant based on the PTE established in Title V Permit AQ1121TVP02, Revision 2. The effective emission rate is calculated as follows:

  Permitted PTE: 1,764 tons of SO_2
  Permitted coal consumption limit: 336,000 tpy
  Assumed coal energy content: 7,600 British thermal units per pound (Btu/lb)

1,764 tons SO_2/yr * 1 year/336,000 tons coal * 1 lb coal/7,600 Btu * 10^6 Btu/MMBtu * 1 ton coal/2,000 lb coal * 2,000 lb SO_2/ton
= 0.691 lb SO_2/MMBtu

The difference between the ADEC-assumed emission rate and the effective emission rate leads to a significant error in the SO_2 cost effectiveness calculation. The ADEC spreadsheet divides the total annualized cost (determined by using the 0.46 lb/MMBtu SO_2 rate) by the SO_2 PTE (with an effective rate of 0.691 lb/MMBtu). The use of two different emission rates in this calculation results in an invalid comparison of two values that should not be compared to each other. For the result of the equation to be valid, the total annualized cost must be calculated using an SO_2 emission rate equal to the SO_2 PTE.

- Conclusion: Based on the review of the preliminary SO_2 BACT determination and the associated cost effectiveness calculation, no indication could be found that the Preliminary Determination calculation accurately reflects the actual operating conditions for EUs 1 through 6. As a result, no basis exists for determining if the installation of a DSI system is or is not economically feasible. Despite the inability to determine the accuracy of the calculations in the Preliminary Determination, those calculations likely underestimate the DSI cost effectiveness because the Preliminary Determination underestimates SO_2 emissions on a lb/MMBtu basis.

  If a more accurate cost effectiveness is to be determined, the cost effectiveness should be recalculated using a bottom-up cost estimating approach based on actual plant conditions. These conditions would include SO_2 emission rates based on current PTE, permit constraints (where applicable and enforceable), available space, ambient conditions, and local factors such as construction logistics, labor wage rates, and local sorbent costs.

21. Section 5.1 (Industrial Coal-fired Boilers), Step 5: The proposed coal combustion limit of 300,000 tpy and the assumption that the coal sulfur content is no greater than 0.2 weight percent are not evaluated through the five-step BACT process, or even identified as available control technologies in Step 1.
    - The current coal combustion limit for the six boilers is 336,000 tpy, per Condition 12.1 of AQ1121TVP02, Revision 2.
    - The current coal sulfur content is not limited beyond the State SIP SO_2 standard and the requirement to determine what the SO_2 emission concentrations would be prior to combusting coal with a sulfur content of greater than 0.4 weight percent. (Refer to Conditions 11 and 11.1 of AQ1121TVP02, Revision 2.)
    - If either of these requirements is to be imposed as a limit without a BACT analysis justifying the limit, the limit(s) should be used to calculate a revised baseline emission rate. The BACT analysis should then calculate any further emission reductions based on that revised baseline emission rate.

    DU does not agree that either the coal consumption limit of 300,000 tpy or the coal sulfur content assumption of less than or equal to 0.2 weight percent is appropriate. More investigation is needed to determine whether these assumptions are valid and feasible. At the least, the 0.2 weight percent coal sulfur limit should be assessed through the BACT analysis process. DU is not aware that Usibelli Coal Mine, the sole supplier of coal in Alaska, has even been contacted to advise whether the mine is capable of providing coal meeting that specification on a long-term basis. Step 1(d) of the Preliminary Determination acknowledges that the current contract guarantee is less than 0.4 weight percent sulfur, and that the coal typically ranges from 0.08 to 0.28 weight percent sulfur.

22. Section 5.4 (Small Emergency Engines), Step 5(a): The requirement to limit non-emergency operation of small emergency engines is inconsistent with applicable requirements under 40 CFR 63 Subpart ZZZZ (or Subpart IIII, if applicable), which allows 100 hours per year of non-emergency operation but does not restrict those non-emergency operations to maintenance checks and readiness testing.

23. Section 5.4 (Small Emergency Engines), Step 5(b): The determination that good combustion practices is BACT should be eliminated or a rationale should be provided for selecting good combustion practices in addition to the combustion of ULSD and limited operations. Per Table 5-10 of the Preliminary Determination, good combustion practices were not determined to be SO_2 BACT for small diesel-fired engines at other stationary sources. While DU follows good combustion practices as a standard practice, Step 3(c) indicates that good combustion practices are the least effective SO_2 emission control technology.

Attachment: EPA comments on ADEC Preliminary Draft Serious SIP Development materials for the Fairbanks serious $PM_{2.5}$ nonattainment area

General

The attached comments are intended to provide guidance on the preliminary drafts of SIP documents in development by ADEC. We expect that there will be further opportunities to review the more complete versions of the drafts and intend to provide more detailed comments at that point

1. Statutory Requirements - This preliminary draft does not address all statutory requirements laid out in Title I, Part D of the Clean Air Act or 40 C.F.R. Part 51, Subpart Z. The submitted Serious Area SIP will need to address all statutory and regulatory requirements as identified in Title I, Part D of the Clean Air Act, 40 C.F.R. Part 51, Subpart Z, the August 24, 2016 $PM_{2.5}$ SIP Requirements Rules (81 FR 58010, also referred to at the $PM_{2.5}$ Implementation Rule), and any associated guidance.

   In the preliminary drafts, notable missing elements included: Reasonable Further Progress, Quantitative Milestones, and Conformity. This is not an exhaustive list of required elements.

   The NNSR program is a required element for the serious area SIP. We understand ADEC recently adopted rule changes to address the nonattainment new source review element of the Serious SIP, and that ADEC plans to submit them to the EPA separately in October 2018. Thank you for your work on this important plan element.

2. Extension Request - This preliminary draft does not address the decision to request an attainment date extension and the associated impracticability demonstration. On September 15, 2017, ADEC sent a letter notifying the EPA that it intends to apply for an extension of the attainment date for the Fairbanks $PM_{2.5}$ Serious nonattainment area. The Serious Area SIP submitted to EPA will need to include both an extension request and an impracticability demonstration that meet the requirements of Clean Air Act section 188(e). In order to process an extension request, the EPA requests timely submittal of your Serious Area SIP to allow for sufficient time to review and take action prior to the current December 2019 attainment date, so as to allow, if approvable, the extension of the attainment date as requested/appropriate. For additional guidance, please refer to 81 FR 58096.

3. Split Request - We support the ADEC and the FNSB's decision to suspend their request to the EPA to split the nonattainment area. We support the effort to site a monitor in the Fairbanks area that is more representative of neighborhood conditions and thus more protective of community health. This would provide additional information on progress towards achieving clean air throughout the nonattainment area.

4. BACM (and BACT), and MSM - Best Available Control Measures (including Best Available Control Technologies) and Most Stringent Measures are evaluative processes inclusive of steps to identify, adopt, and implement control measures. Their definitions are found in 51.1000, 51.1010(a).

All source categories, point sources – area sources – on-road sources – non-road sources, need to be evaluated for BACM/BACT and MSM. De minimis or minimal contribution are not an allowable rationale for not evaluating or selecting a control measure or technology.

The process for identifying and adopting MSM is separate from, yet builds upon, the process of selecting BACM. Given that Alaska is intent on applying for an extension to the attainment date, Alaska must identify BACM and MSM for all source categories. These processes are described in 51.1010(a) and 51.1010(b) and in the $PM_{2.5}$ Implementation Rule preamble at 81 FR 58080 and 58096. We further discuss this process in the "BACM (and BACT), MSM" section that starts on page 3 below.

5. Resources and Implementation - The serious area $PM_{2.5}$ attainment plan will be best able to achieves its objectives when all components of the SIP, both the ADEC statewide and FNSB local measures, are sufficiently funded and fully implemented.

6. Use of Consultants- For the purpose of clarity, it will be important to identify that while contractors are providing support to ADEC, all analyses are the responsibility of the State.

Emissions Inventory

1. Extension Request Emission Inventories - Emissions inventories associated with the attainment date extension request will need to be developed and submitted. Table 1 of the Emissions Inventory document is one example where the submittal will need to include the additional emissions inventories, including RFP inventories, extension year inventories for planning and modeling, and attainment year planning and modeling inventories, associated with the attainment date extension request.

2. Modeling Requirements - Related to emissions inventory requirements, the serious area SIP will need to model and inventory 2023 and 2024, at minimum. We recommend starting at 2024 and modeling earlier and earlier until there is a year where attainment is not possible. That would satisfy the requirement that attainment be reached as soon as practicable.

3. Condensable Emissions - All emissions inventories and any associated planning, such as Reasonable Further Progress schedules, need to include condensable emissions as a separate column or line item, where available. Where condensable emissions are not available separately, provide condensable emissions as included (and noted as such) in the total number. The following are examples of where this would need to be incorporated in to the Emissions Inventory document:
   a. Page 20, paragraph 5 (or 2nd from the bottom).
   b. Page 34, Table 8. Include templates.

<u>Precursor Demonstration</u>

1. <u>Ammonia Precursor Demonstration</u> - The draft Concepts and Approaches document, Table 4 on page 9, states that a precursor demonstration was completed for ammonia and that the result was "Not significant for either point sources or comprehensively." The Precursor Demonstration chapter does not include an analysis for ammonia. Please include the precursor demonstration for ammonia in the Serious Plan or amend this table.

2. <u>Sulfur Dioxide Precursor Description</u> - The draft Concepts and Approaches document, Table 4 on page 9, states that sulfur dioxide was found to be significant. All precursors are presumptively considered significant by default and the precursor demonstration can only show that controls on a precursor are not required for attainment. Suggested language is, "No precursor demonstration possible."

<u>BACM (and BACT), MSM</u>

Overall

The EPA appreciates ADECs efforts to identify and evaluate BACM for eventual incorporation into the Serious Area SIP. The documents clearly display significant effort on the part of the state and are a good first step in the SIP development process. In particular, we are supportive of ADECs efforts to evaluate BACT for the major stationary sources in the nonattainment area, as control of these sources is required by the CAA and $PM_{2.5}$ SIP Requirements Rule.

1. <u>BACM/BACT and MSM: Separate Analyses</u> - The "Possible Concepts and Potential Approaches" document appears to conflate the terms BACM/BACT and MSM, as well as, the analyses for determining BACM/BACT and MSM. BACM and MSM have separate definitions in 40 CFR 51.1000. By extension, the processes for selecting BACM and MSM are laid out separately in the $PM_{2.5}$ SIP Requirements Rule (compare 40 CFR 51.1010(a) for BACM and 40 CFR 51.1010(b) for MSM). Accordingly, the serious area SIP submission will need to have both a BACM/BACT analysis and an MSM analysis. We believe that there is flexibility in how these analyses can be presented, so long as the submission clearly satisfies the requirements of both evaluations, methodologies, and findings.

2. <u>Selection of Measures and Technologies</u> - The CAA and the $PM_{2.5}$ SIP Requirements Rule requires that ***<u>all</u>*** available control measures and technologies that meet the BACM (including BACT) and MSM criteria need to be implemented. All source categories need to be evaluated including: point sources (including non-major sources), area sources, on-road sources, and non-road sources.

3. <u>Technological Feasibility</u> - All available control measures and technologies include those that have been implemented in nonattainment areas or attainment areas, or those potential measures and technologies that are available or new but not yet implemented. Similarly, Alaska may not automatically eliminate a particular control measure because other sources or nonattainment areas have not implemented the measure. The regulations do not have a quantitative limit on number of controls that should be implemented.

For technological feasibility, a state may consider factors including local circumstances, the condition and extent of needed infrastructure, or population size or workforce type and habits, which may prohibit certain potential control measures from being implementable. However, in the instance where a given control measure has been applied in another NAAQS nonattainment area, the state will need to provide a detailed justification for rejecting any potential BACM or MSM measure as technologically infeasible (81 FR 58085).

A Borough referendum prohibiting regulation of home heating would not be an acceptable consideration to render potential measures technologically infeasible. The State would be responsible for implementing the regulations in the case that the Borough was not able. We believe that the most efficient path to clean air in the Borough is through a local, community effort.

4. Economic Feasibility - The BACM (including BACT) and MSM analyses need to identify the basis for determining economic feasibility for both the BACM and MSM analyses. In general, the $PM_{2.5}$ SIP Requirements Rule requires the state apply more stringent criteria for determining the feasibility of potential MSM than that used to determine the feasibility of BACM and BACT, including consideration of higher cost/ton values as cost effective.

5. Timing - The evaluations will need to identify the time for selection, adoption, and implementation for all measures. BACT must be selected, adopted, and implemented no later than 4 years after reclassification (June 2021). MSM must be selected, adopted, and implemented no later than 1 year prior to the potentially extended attainment date (December 2023 at latest). The RFP section of the serious area plan will need to identify the BACM and MSM control measures, their time of implementation, and the time(s) of expected emissions reductions. Timing delays in selection, adoption, implementation are not considered for BACM and MSM.

   As mentioned in the comment above in the “General” comment section, there are three criteria distinguishing between BACM and MSM, not one.

BACM - General

1. BACM definition, evaluations - The definition of BACM at 40 CFR 51.1000 describes BACM as any measure “that generally can achieve greater permanent and enforceable emissions reductions in direct $PM_{2.5}$ and/or $PM_{2.5}$ plan precursors from sources in the area than can be achieved through the implementation of RACM on the same sources.” We believe that potential measures that are no more stringent than existing measures already implemented in FNSB, those that do not provide additional direct $PM_{2.5}$ and/or $PM_{2.5}$ precursors emissions reductions, do not meet the definition of BACM. These would need to be evaluated in the BACM and MSM analysis.

   For measures that are currently being implemented in Fairbanks that provide equivalent or more stringent control, we recommend identifying the ADEC or Borough implemented measure as part of the BACM control strategy. These implemented measures should be listed in their BACM findings at the end of the document. This comment applies to all of the measures that were screened out from consideration due to not being more stringent than the already implemented measure.

The analyses for a number of measures (e.g., Measure 30, Distribution of Curtailment Program information at time of woodstove sale) conclude that the emission reductions would be insignificant and difficult to quantify and, therefore, the measure is not technologically feasible. These measures may be technologically feasible. However, if existing measures constitute a higher level of control or if implementation of the measures is economically infeasible those would be valid conclusions if properly documented. De minimis or minimal contribution is not a valid rationale for not considering or selecting a control measure or technology.

The conclusion "not eligible for consideration as BACM" is not valid as all assessments for BACM and MSM are part of the evaluation. More appropriate conclusions could include that existing measures qualify as BACM or MSM, or are more stringent. Additional conclusions could include that evaluated measures were not technologically feasible, economically feasible, or could not practically be adopted and implemented prior to the required timeframe for BACM or MSM.

2. BACM and MSM, Ammonia - In the Approaches and Concepts document, Table 5 references that there are no applicable control measures or technologies for the $PM_{2.5}$ precursor ammonia. No information to substantiate this claim are found in the preliminary draft documents. Unless NH_3 is demonstrated to be insignificant for this area, the serious area plan will need to include an evaluation of NH_3 and potential controls for all source categories including points sources.

3. Backsliding Potential - When benchmarking the BACM and MSM analyses for stringency, ensure that the evaluation is based on the measures approved into the current Moderate SIP. This will relate primarily to the current ADEC/FNSB curtailment program but also other related rules. Many wood smoke control measures are interrelated, and changes to those measures may affect determinations on stringency of directly related and indirectly related measures. Examples of this can be found in multiple measures including, but not limited to Measures 5, 7, and 16.

4. Transportation Control Measures - The Approaches and Concepts document, on Page 13, states that the MOVES2014 model does not estimate a PM benefit as a result of an I/M program, and therefore the I/M is not technologically feasible. This is not a valid conclusion given that the Fairbanks area operated an I/M program to reduce carbon monoxide and the Utah Cache Valley nonattainment areas has an I/M program for VOC control. This measure will need to be evaluated. Referring to the 110(l) analysis for the Fairbanks CO I/M program may provide insight into how to quantify the emissions associated with an I/M program.

With regard to control measures related to on-road sources, we have received inquiries from the community regarding idling vehicles and further evaluation emission benefits would be responsive to citizen concern and may provide additional air quality benefit.

BACM - Specific Measures

- Measure 16, page 34-35. Date certain Removal of Uncertified Devices. The "date certain" removal of uncertified woodstoves in Tacoma, Washington appears more stringent than the current Moderate SIP approved Fairbanks ordinance in terms of the regulation and in practice. While the current ordinance appears to provide similar protection during stage 1 alerts, this is dependent on 100% compliance and the curtailment program remaining in its current form. Removal of uncertified stoves guarantees reductions in emissions in the airshed during both the curtailment periods and throughout the heating season. The information provided does not support the conclusion that the Fairbanks controls provides equivalent or more stringent control. Date certain removal of uncertified wood stoves needs to be considered for the area.

  Measures R4, R9, and R12, page 64, 68 and 71. These measures do not reference the Puget Sound Clean Air Agency (Section 13.07) requirement for removal of all uncertified stoves by September 30, 2015. This is equivalent to having all solid fuel burning appliances be certified and would be more stringent than the current SIP approved rules in Fairbanks. We believe that these measures need to be evaluated in the BACM and MSM analyses.

  Measure R4 and R9, page 64 and 68. All Wood Stoves Must be Certified. These measure should be evaluated.

- Measure 19-20 and 25, page 36-38 and 39. Renewal and Inspection Requirements. ADEC has not adequately demonstrated their conclusion that Fairbanks has a more stringent measure than Missoula and San Joaquin. We believe that the renewal requirements and inspection/maintenance requirements associated with the Missoula alert permits and San Joaquin registrations allows the local air agency an opportunity to verify on a regular basis that the device operates properly over times. Wood burning appliances require regular maintenance in order to achieve the certified emissions ratings. The FNSB Stage 1 waivers do not have an expiration and do not have an inspection and maintenance component making it less stringent.

- Measure 31, page 43. While the Borough has SIP approved dry wood requirements that prohibit the burning of wet wood and moisture disclosure requirements by sellers, we believe that a measure limiting the sale of wet wood during the winter months should be further analyzed for BACM (and MSM) consideration.

- Measures 33, 35, 36, 37, 43. Multiple Measures identify that recreational fires have been exempted from existing regulations. Small unregulated recreational fires, bonfires, fire pits, and warming fires have the potential to contribute emissions during a curtailment period. The FNSB and ADEC regulations should be re-evaluated for removing this exclusion.

- Measure 49, page 58. Ban on Coal Burning. We believe the regulations in Telluride are more stringent than in Fairbanks. Telluride prohibits coal burning all year whereas in Fairbanks an existing coal stove can burn when there is no curtailment which could contribute additional emissions to the airshed, especially during poor conditions when a curtailment may not have been called. We do not agree with the conclusion that the PM_{10} controls are ineligible for consideration for control of $PM_{2.5}$.

- Measure R20, page 76. Transportation Control Measures related to Vehicle Idling. We have received multiple inquiries regarding community interest in controlling emissions from idling vehicles. These types of control measures should be further evaluated in the BACM and MSM analyses.

- Measure 1, page 79-81. Surcharge on Solid Fuel Burning Appliances. For purposes of implementing an effective program to reduce $PM_{2.5}$ in the Borough we believe that a surcharge may be a helpful way to supplement limited funds. Implementation efforts within the nonattainment area could benefit from $24,000 of additional funding whether used for a code enforcer or other support of the wood smoke programs.

- Additional controls that should be further evaluated for BACM and MSM include:
  - Measure R1, page 63: Natural gas fired kiln or regional kiln.
  - Measure R12, page 71: Replace uncertified stoves in rental units.
  - Measure R17, page 75: Ban use of wood stoves
  - Measure R6, page 65: Remove Hydronic Heaters at Time of Home Sale & Date certain removal of Hydronic heaters. We suggest evaluating these measures at the state and local level.
  - Weatherization / heat retention programs should be evaluated. These should be evaluated for existing homes through energy audits and increasing insulation and energy efficiency. For new construction, building codes (Fairbanks Energy Code) should be evaluated with reference to the IECC Compliance Guide for Homes in Alaska http://insulationinstitute.org/wp-content/uploads/2015/12/AK_2009.pdf, and the DOE R-value recommendations, http://www.fairbanksalaska.us/wp-content/uploads/2011/07/ENERGY-CODE.pdf. (Note: More recent information may be available.)
  - Fuel oil boiler upgrades / operation & maintenance programs should be evaluated.

BACM - Ultra-Low Sulfur Fuel

1. Incomplete Analysis - The report findings provide analysis of the demand curve over a relatively short (12 month) time frame. This analysis appears to be based on a partial equilibrium model. This is a misleading time frame given the volatility of demand side fuel oil pricing. Also, in order to determine the equilibrium price, the analysis must also analyze

the supply curve. The report does not include information about the future supply side costs but needs to in order to make conclusions about the cost to the community of ultra-low sulfur heating oil.

2. Analysis of Increased Supply, Consumption - The report does not address future change in the market nor potential economies of scale to be achieved by an increase in ultra-low sulfur fuel consumption. Page 3 of the report identifies that, "the additional premium to purchase ULS over HS, decreased significantly since 2008-2010. It is likely that, this can be attributed to increased ULS capacity." We believe that the report should further explore the supply side costs.

3. Supply Cost Analysis - A supply side cost analysis is necessary to better understand the cost to the supplier to produce and provide ULS heating fuel. The BACM analysis must start with a transparent and detailed economic analysis of exclusively supplying ultra-low sulfur heating oil to the nonattainment area.

4. BACM Assessment - The current analysis does not provide information needed to assess BACM economic feasibility. The report should analyze the total cost to industry of delivering ultra-low sulfur heating oil to the entire community in terms of standard BACM metrics, $/ton.

BACT

General Comments

At this time, EPA is providing general comments based on review of the draft BACT analyses prepared by ADEC as well as addressing certain issues discussed in earlier BACT comments provided by EPA. Detailed comments regarding each individual analysis are not being provided at this time. While EPA appreciates the time and effort invested by ADEC staff in preparing the draft BACT analyses, the basic cost and technical feasibility information needed to form the basis for retrofit BACT analyses at the specific facilities has not been prepared. In other words, analyses which are adequate to guide decision making regarding control technology decisions for these rather complex retrofit projects cannot be prepared without site specific evaluation of capital control equipment purchase and installation costs, and site specific evaluation of retrofit considerations. EPA will conduct a thorough review of any future BACT or MSM analyses which are prepared based on adequate site specific information, and will provide detailed comments relative to each emission unit and pollutant at that time.

1. Level of Analysis – The analyses are presented as "preliminary BACT/MSM analyses" on the website, but the documents themselves are titled only as BACT analyses and the conclusions only reflect BACT. Additionally, the determinations may not be stringent enough to be considered BACT given that better performing SO_2 control technologies have not been adequately analyzed. These analyses cannot be considered to provide sufficient basis to support a selection of MSM.
2. Site-Specific Quotes Needed – The cost analyses, particularly for SO_2 control technologies, must be based on emission unit-specific quotes for capital equipment purchase and

installation costs at each facility. These are retrofit projects which must be considered individually in order to obtain reliable study/budget level (+/- 30%) cost estimates which are appropriate to use as the basis for decision making in determining BACT and potentially MSM. EPA believes that control decisions of this magnitude justify the relatively small expense of obtaining site-specific quotes.

3. SO_2 Control Technologies – The analyses must include evaluation of circulating dry scrubber (CDS) SO_2 control technology. This demonstrated technology can achieve SO_2 removal rates comparable to wet flue gas desulfurization (FGD) at lower capital and annual costs, and is more amenable to smaller units and retrofits. Modular units are available.
4. Control Equipment Lifetime – The analyses must use reasonable values for control equipment lifetime, according to the EPA control cost manual (EPA CCM). EPA believes that the following equipment lifetimes reflect reasonable assumptions for purposes of the cost analysis for each technology as stated in the EPA control cost manual and other EPA technical support documents. Use of shorter lifetimes for purposes of the cost analysis must include evidence to support the proposed shortened lifetime. One example where EPA agrees a shortened lifetime is appropriate would be where the subject emission unit has a federally enforceable shutdown date. Certain analyses submitted in the past have claimed shortened equipment lifetimes based on the harshness of the climate in Fairbanks. In order to use an equipment life that is shortened based on the harsh climate, evidence must be provided to support the claim. This evidence could include information regarding the actual age of currently operating control equipment, or design documents for associated process equipment such as boilers. Lacking adequate justification, all cost analyses must use the following values for control equipment lifetime:
   a. SCR, Wet FGD, DSI, CDS, SDA – 30 years
   b. SNCR – 20 years
5. Availability of Control Technologies – Technologically feasible control technologies may only be eliminated based on lack of availability if the analysis includes documented information from multiple control equipment vendors (who provide the technology in question) which confirms the technology cannot be available within the appropriate implementation timeline for the emission unit in question.
6. Assumptions and Supporting Documents – All documents cited in the analyses which form the basis for costs used and assumptions made in the analyses must be provided. Assumptions made in the analyses must be reasonable and appropriate for the control technologies included in the cost analysis.
7. Interest Rate – All cost analyses must use the current bank prime interest rate according to the revised EPA CCM. As of May 10, 2018, this rate is 4.75%. See https://www.federalreserve.gov/releases/h15/ (go to bank prime rate in the table).
8. Space Constraints – In order to establish a control technology as not technologically feasible due to space constraints or other retrofit considerations, detailed site specific information must be submitted in order to establish the basis for such a determination, including detailed drawings, site plans and other information to substantiate the claim.
9. Retrofit Factors – All factors that the facility believes complicate the retrofit installation of each technology should be described in detail, and detailed substantiating information must be submitted to allow reasonable determination of an appropriate retrofit factor or whether installation of a specific control technology is technologically infeasible. EPA Region 10

believes that installation factors which would complicate the retrofit installation of the control technology should be evaluated by a qualified control equipment vendor and be reflected in a site-specific capital equipment purchase and installation quote. Lacking site-specific cost information, all factors that the facility believes complicate the retrofit installation of each technology should be described in detail, and detailed substantiating information must be submitted to allow reasonable determination of an appropriate retrofit factor. One example of the many retrofit considerations that must be evaluated is the footprint required for each control technology. A vendor providing a wet scrubber will be able to estimate the physical space required for the technology, and evaluate the existing process equipment configuration and available space at each subject facility. The determination of whether a specific control technology is feasible and what the costs will be may be different at each facility based on this and other factors. Site-specific evaluation of these factors must be conducted in order to provide a reasonable basis for decision making.

10. Control Efficiency – Cost effectiveness calculations for each control technology must be based on a reasonable and demonstrated high end control efficiency achievable by the technology in question at other emission units, or as stated in writing by a control equipment vendor. If a lower pollutant removal efficiency is used as the basis for the analysis, detailed technical justification must be provided. For example, the ability of SCR to achieve over 90% NO_X reduction is well established, yet the ADEC draft analyses assume only 80% control. Use of this lower control efficiency requires robust technical justification.
11. Condensable Particulate Matter – Although the existing control technology on the coal fired boilers may be evaluated as to whether it meets the requirement for BACT for particulate matter, baghouses primarily reduce emissions of filterable particulate matter rather than condensable PM. Given that all condensable PM emitted by the coal fired boilers would be classified as $PM_{2.5}$, the BACT analyses must include consideration of control options for these emissions. Where control technologies evaluated for control of other pollutants may provide a collateral benefit in reducing emissions of $PM_{2.5}$, this should be evaluated as well.
12. Guidance Reference – The steps followed to perform the BACT analysis mentioned in section 2 are from draft NSR/PSD guidance. The correct reference should be 81 FR 58080, 8/24/2016. As a result of this, some of the steps outlined in the BACT analysis need to be updated.
13. Community Burden Estimate – The concepts and approaches document labels capital purchase and installation costs for air pollution control technology at the major source facilities as "community burden" (see Tables 7 and 8, pages 10-11). EPA believes it is important to properly label the cost numbers being used as capital purchase and installation costs, since presenting them as community burden appears to attribute the entire initial capital investment for the various control technologies to the community in a single year, and also ignores annual operation and maintenance costs. As described in the EPA CCM, the cost methodology used by EPA for determining the cost effectiveness of air pollution control technology amortizes the initial capital investment over the expected life of the control device, and includes expected annual operating and maintenance expenses. EPA believes presentation of this annualized cost over the life of the control technology more accurately represents the actual cost incurred and is consistent with how cost effectiveness is estimated in the context of a BACT analysis.
14. Conversion to Natural Gas – For any emission units capable of converting to natural gas combustion (with the requisite changes to the burners, etc), the MSM analysis in particular

should thoroughly evaluate the feasibility of this option. For example, GVEA has stated the combustion turbines at its North Pole Expansion Power Plant have the ability to burn natural gas, and the IGU has indicated the intent to expand the supply of natural gas to Fairbanks and North Pole.

APPENDIX:

Additional Comments and Suggestions

Possible Concepts and Potential Approaches

Throughout all SIP documents references to design values should include a footnote to the source of the information (e.g., "downloaded from AQS on XX/XX/XXX" or "downloaded from [state system] on XX/XX/XXXX") and how exceptional events were treated.

We suggest referencing the August 24, 2016 81 FR 58010 Fine Particulate Matter NAAQS: State Implementation Plan Requirements rule with one consistent term. We suggest the 2016 $PM_{2.5}$ Implementation Rule.

Page 4, Figure 1. The comparative degree days and heating related information is better suited for the sections evaluating BACM and economic feasibility. If intending on using this information to differentiate Fairbanks from other cold climates and/or nonattainment areas, depicting comparative home heating costs would be more supportive.

Page 4, Table 1. The design values in the table and in the discussion need to be updated for 2015-2017.

Page 6-7: The "Totals" row in Table 3 (non-attainment areas emissions by source sector) does not appear to be the sum of the individual source sector emissions.

Page 7: The statement about FNSB experiencing high heating energy demand per square foot needs to be referenced.

Page 7: The discussion of Eielson AFB growth needs a reference to the final EIS.

Page 9: Table 4's title should be changed to "Preliminary Precursor Demonstration Summary"

Page 9: Table 4 includes a column "Modeling Assessment". Not all precursors were assessed with modeling, and modeling is just one tool for the precursor demonstration. A suggestion for the column title is "Result of Precursor Demonstration."

Page 9: Table 5's title should be changed to "Preliminary BACT Summary." Table 5 also needs to update the title to reference "Precursor Demonstration" as the term "Precursor Significance Evaluation" is the incorrect terminology for this analysis.

Page 10: ADEC's proposal to only require one control measure per major stationary source to meet BACT and MSM for SO_2, is not consistent with the Act or rule. As discussed above, BACM and MSM have separate definitions in 40 CFR 51.1000. By extension, the processes for selecting BACM and MSM are laid out separately in the PM2.5 SIP Requirements Rule (compare 40 CFR 51.1010(a) for BACM and 40 CFR 51.1010(b) for MSM).

Page 10: Table 6 should identify the specific dry sorbent injection selected as BACT.

Page 11: Suggest changing “less sources” to “fewer sources.”

Page 13: The statement about an I/M program providing PM benefit needs to be clarified. Is this referring just to NOx and VOC precursor contribution to PM2.5, or also direct PM2.5 benefits?

Page 14: The statement “ADEC interprets the main difference between BACT/BACM and MSM as the time it takes to implement a control” is inaccurate. As discussed above, although the rule sets our different schedules for implementation of MSM and BACM, this is not the only major difference between those concepts. Notably, the rule contemplates a higher stringency for MSM as well as a higher cost/ton threshold for determining economic feasibility of the measure.

Technical Analysis Protocol

Page 2: The design values at the top of the page need to be updated to 2015-2017.

Page 2: Recommend removing the sentence “This site will be included in the Serious SIP’s attainment plan…” as the North Pole Elementary will be involved in the redesignation to attainment in the sense that all past and current monitoring data will be a part of an unmonitored area analysis to show that the entire area has attained the standard in addition to the regulatory monitor locations.

Page 2: Remove the discussion of the nonattainment area split.

Page 2: Paragraph 2, sentence 3 should refer to the unmonitored area analysis.

Page 2: The timeline described at the bottom of the page needs to be modified to reflect a current schedule. No projected year modeling was included in the preliminary draft documents. Control scenario modeling will likely not be completed in Q2 2018.

Page 3: We suggest a sentence overview of the unmonitored area analysis in Section 3.1.

Page 3: Section 3.2 needs to refer to the SPM data and how that will be used in the Serious Plan unmonitored area analysis. This section should discuss current DEC efforts to site a new monitor in Fairbanks.

Page 3: Section 3.4 needs to describe the CMAQ domain in addition to the WRF domain. A figure (map) would help.

Page 4: Section 3.5 needs a more developed discussion of the WRF assessment, including describing the criteria that were used to assess the state-of-the-art, what the current version is, and what version was used.

Page 4: Section 3.6 needs to reference all emission inventories in development, including potential attainment date extension years and RFP years.

Page 4: In Section 4.1, the statement about the Moderate SIP covering the relevant monitors for the Serious SIP is inaccurate. The statement needs to qualify whether it is referring to regulatory monitors or non-regulatory monitors. In addition, the North Pole Fire Station, NCore, and North Pole Elementary monitors were not included in the Moderate SIP.

Page 5: Table 4.1-1's title suggests that all SPM sites are listed, but only sites with regulatory monitors are listed. Please list all the SPM sites used in the unmonitored area analysis in a separate table and modify this title of Table 4.1-1 to reflect that it lists sites that are regulatory.

Page 5: North Pole Elementary was a regulatory site for a part of the baseline period and was NAAQS comparable. Table 4.1-1 needs to be updated.

Page 8: Table 4.2-1 should be updated to include 2011-2017 98th percentiles. Table 4.2-2 should be updated to include 3-year design values for 2013-2017. For clarity, we recommend the 3-year design values include the full period in order to better distinguish from Table 4.2-1. For instance, "2013" would be "2011-2013".

Page 8: The statement starting, "a clear indication…" needs to be amended or removed. It is inaccurate. The prevalence of organic carbon does not indicate the dominance of wood burning, much less a clear indication. Many sources in Fairbanks emit organic carbon.

Page 8: The statement starting "The concentration share…" need to be amended or removed. Suggest removing "drastically". There is no scientific definition of a drastic change in percentages of $PM_{2.5}$ species, nor does the different 56% to 80% appear "drastic."

Page 9: The detailed description of the Simpson and Nattinger analysis does not reflect that SANDWICH process and it is preliminary data. It should be included within the body of the Serious Plan appendix on monitoring, but is out of place in a summary TAP.

Page 9: there are two different tables with the same table number (Table 4.3-1).

Page 10: Please clarify Table 4.4-1. This appears to be the design value calculation for the 5-year baseline design value, 2011-2015. If correct, then please label the 3-year design values according to the three years (e.g., "2011-2013"), clarify the table heading as being the "Five Year Baseline Design Value, 2011-2015 (µg/m3)", and clarify that the last column is the 5 Year Baseline Design Value associated with the table heading.

Page 11: At the end of section 5, please refer to the emission inventory chapter's meteorological discussion of the episodes.

Page 11: Section 6 needs to justify the extent, resolution, and vertical layer structure of the CMAQ domain (and the WRF domain) or refer to where that is included in the Moderate Plan.

Page 13: We suggest changing "PMNAA" to "NAA" to be consistent with the EI chapter.

Page 15, Section 8.1: There needs to be mention of how the F-35 deployment will be considered, with a reference to the final EIS.

Page 15-19: section 8.2-8.6 use the future tense for tasks that have been completed and are inconsistent with the schedule at the beginning of the TAP. Please adjust based on current status.

Page 20, section 9.2 states that "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." This sentence should be revised to reflect that the technological feasibility assessment occurs after identification of all potential control measures for each source and source category.

Page 20, section 9.3 the second sentence should read: "BACM measures found to be economically infeasible for BACM *must* be analyzed for MSM."

Page 21: Section 10.1 needs to be updated to reflect the current CMAQ version (5.2.1) and a discussion of why that model has not been used.

Page 21: Suggest sentence starting "There will be a gap…" be changed to "There is a gap in terms of assessing the performance at the North Pole Fire Station monitor for the Serious Plan because the State Office Building in Fairbanks was the only regulatory monitor at the time of the 2008 base case modeling episodes."

Page 23: Please explain the solid and dashed lines in the soccer plot.

Page 23: Please be sure to include a full discussion of North Pole performance in this section. Even though we lack measurements, we can discuss the ratio of the modeling results at NPFS versus SOB versus that ratio from more recent monitoring data (2011-2015 baseline design value period).

Page 23: Please clarify what is meant by "Moderate Area SIP requirements."

Page 24: The discussion of the 2013 base year discusses representative meteorological conditions without describing what the representative meteorological conditions are for high $PM_{2.5}$. Please reference the discussion of representative meteorological conditions that will be found elsewhere in the SIP.

Page 24: The discussion of the modeling years needs to be consistent and reflect the extension request past 2019. The attainment year cannot be earlier than 2019. Each extension year must be individually requested. For modeling efficiency, we recommend starting with 2024. If that year attains, then 2023 and so on until we have one year that attains and the year before that does not. This should give us the information about what is the earliest year for attainment.

Page 25: We suggest changing "modeling design value" to "design value for modeling"

Page 26: Please clarify the "SMAT" label in the tables. They may be the SANDWICH concentrations and the "5-yr DV" rows are the SMAT concentrations. Please clarify the units in the rows.

Emission Inventory

Clarification – In the EI document we would like to understand the functional difference between the base year, and baseline year

Please identify the methodology for generating ammonia and condensable PM emissions numbers.

Page 1: Please be consistent in "emission inventory" versus "emissions inventory".

Page 1: "CAA" to "Clean Air Act" for clarity

Page 3: It would be helpful to refer to 172(c)(3) in Section 1.2, bullet 1 as the planning and reporting requirements.

Page 5: Please include extension years and RFP years in Table 1's calendar years similar to what was done for Table 2. There should be one RFP projected inventory and QM beyond the extended attainment date. It would be helpful to include basic information about extension years and RFP years to better foreshadow Table 2.

Page 7: Please clarify the "winter season" inventory as the "seasonal" inventory that represents the daily average emissions across the baseline episodes.

Page 7, paragraph 1. Please include reference documentation for the following statement, "results in extremely high heating energy demand per square foot experienced in no other location in the lower-48."

Page 9: Please change "Violations" to "Exceedances." Exceedance is the term for concentrations over the standard. Violations is the term for dv over the standard.

Page 9: Add "No exceedances were recorded outside the months tabulated in Table 3 that were not otherwise flagged by Alaska DEC as Exceptional Events.", to the end of the last paragraph on the page.

Page 13: Please clarify the provenance of the BAM data (e.g., "downloaded from [state database or AQS] on XX/XX/XXXX). In particular, it is important to note if the data has been calibrated to the regulatory measurement (aka, corrected BAM).

Page 17-18. Sentence Unclear "For example, a planning inventory based on average daily emissions across the entire six-month nonattainment season will likely reflect a relatively lower fraction of wood use-based space heating emissions than one based on the modeling episode day average since wood use for space heating Fairbanks tends to occur as a secondary heating source on top of a "base" demand typically met by cleaner home heating oil when ambient temperatures get colder."

Page 19: Remove "Where appropriate,". All source sectors should be re-inventoried for 2013, even if the emissions for the sector ends up being the same as in 2008.

Page 19: Change “projected forward” to “re-inventoried”, or similar wording. Reserve “project” for when the emission inventory is estimating emissions in a future year.

Page 20: Please refer to EPA’s memo on the use of MOVES2014a for the plug in adjustment. As a reminder, this information is sufficient only for development of the emissions inventory, not for SIP credit.

Page 20: Please submit the technical appendix referenced on page 20. When that is submitted, we expect to provide additional comment. To allow for review, we request expedited submission.

Page 21: At bottom of page, “project” should be “re-inventoried” or something that refers to an inventory produced after the fact.

Page 22, paragraph 1, Space heating area sources. Please further explain how the combined survey data best represents 2013 emissions.

Page 23: Add information about how NH_3 was inventoried for this category.

Page 23, 2nd paragraph from bottom. Facilities need to provide direct PM and all precursors, whether directly submitted or calculated from emissions factors.

Page 23, last paragraph.

- Potential typo – we believe that 2018 should be 2013.
- Question – Does scaling emissions cause any point source to exceed its PTE?

Page 25, bullet 3, Laboratory – Measured Emissions Factors for Fairbanks Heating Devices. The statement “first and most comprehensive systematic” would be more credible if simplified.

Page 27: Clarify how data from the 2014 NEI was modified to reflect emissions in 2013. Were they assumed to be the same between the two years? Or adjusted based on population change, or some other information?

Page 33: Please include information on how the Speciate database was used to develop the modeling inventory (and perhaps elsewhere for the planning inventory, if appropriate).

Precursor Demonstration

Throughout the Serious Area SIP we recommend using the terminology, Precursor Demonstration, to be consistent with the $PM_{2.5}$ Implementation Rule.

General: The overview of the nitrate chemistry is complicated. We suggest you combine the two discussions into one and organize it with the following logic:

1. Describe the two chemical environments: (1) daytime and (2) nighttime.
2. Describe the information that supports that daytime chemistry is not relevant here.
3. Describe the information that supports that nighttime chemistry is limited by excess NO.

4. Describe what happens if the entire emission inventory was increasing by a factor of 3.6 to get appropriate concentrations in the North Pole area. How does ammonium nitrate change?
5. Describe how increasing the emission inventory and then reducing all source sectors by 75% results in less of a reduction in $P_{M2.5}$ than reducing all source sectors by 75% in the original emission inventory.
6. NOTE: We are willing to provide a rough draft of this organization, if provided the original word document.

Title page: remove “com”

Page 2: Recommend using Section 188-190 instead of 7513-7513b.

Page 2: Recommend moving the last three sentences of the first paragraph to the end of the second paragraph.

Page 2: Please add “threshold” after 1.3 in the third paragraph.

Page 2: Please explain concentration-based and sensitivity-based before using the terms.

Page 2: Please add a footnote whether the numbers in the Executive Summary are SANDWICHed or not.

Page 3: Please change “has decided” to “decided.”

Page 3: Make sure the concentrations listed for ammonia include ammonium sulfate and ammonium nitrate.

Page 5-7: The figure captions say that concentrations are presented but the images themselves have percentages. Please use concentrations for this analysis.

Page 9: The first paragraph says that the point sources are not responsible for the majority of sulfate at the monitors. Please substantiate that claim, or modify it.

Page 13: Please explain the relevance of referring to the VOC emissions of home heating in this summary of VOCs.

Page 14: Recommend adding “… and adjusted to reflect speciated concentrations for a total PM2.5 equal to the five year 2011-2015 design value” to the sentence that starts “The speciated PM2.5 data [were] analyzed.

Page 14: Please include the results of the concentration based analysis, perhaps as a table.

Page 14: Clarify that the concentration used for NH_3 is the ammonium sulfate and ammonium nitrate. See the draft EPA Precursor Demonstration Guidance.

Page 17: Recommend removing “slightly” and removing the sentence referring to rounding to the nearest tenth of a microgram.

Page 17-18: To help understand what is going on with the bounding run versus the normal run, it would be helpful to have the RRFs for the Modeled 75% scenario.

BACM

Page 9 and throughout: For clarity, please refer to the implementation rule as "$PM_{2.5}$" not "PM".

Page 14, Table 3. It would be helpful to include filter speciation data.

Page 16, Table 4: Please identify the RACM measures that were technologically and economically feasible but could not be implemented in the RACM timeline or note there were none.

Page 20 and 25, Table 6 and 7: For the final Table identifying the control measures evaluated, it would be helpful to identify the following: measure, cost/ton, BACM determination, MSM determination, and any additional comments.

Page 24: 12 measures were eliminated because they were determined to offer marginal or unquantifiable benefit. However, a measure may offer marginal benefit but may also cost very little. If there is another explanation for why these measures were not considered that follows the BACM steps, please include that in the Serious Area Plan.

Page 28: Stage 1 alerts are referred to multiple times including in Measure 2 on page 28 and Measure 33, pg 47 and pg 48. Please clarify in these analyses whether the measure applies during all stages of alerts and the associated level of control with each stage.

Page 33: Measure 13 identified that no SIPs existed or EPA guidance/requirements for the measure and incorrectly used that rationale as the conclusion for not considering the measure.

Page 34: The discussion of Measure 15 does not clearly state how Alaska and the Borough ensure that devices are taken out at the point of sale. It also does not clearly state the process for ensuring a NOASH application doesn't involve a stove that should have been taken out at the point of sale. It also states that stoves between 2.5 g/hr and 7.5 g/hr can get a NOASH, whereas page 37 implies that a stove must be <2.5 g/hr to be eligible for a NOASH.

Page 47: Measure 33 in Klamath County and Feather River is more stringent than what exists in Fairbanks now. Fairbanks allows open burning without a permit when there is no stage restriction. Alaska DEC prohibits open burning between November 1 and March 31, but the air quality plan makes it clear that the state relies on the Borough to carry out the air quality program in Fairbanks. The fact that the local borough does not require a permit for open burning outside of curtailments makes this measure less stringent in Fairbanks than in other locations. In addition, Fairbanks does not curtail warming fires during a Stage 1.

Page 48: Measure 34 is less stringent in Fairbanks than in Klamath County. Uncertainty in weather forecasting means that Stage 1 alerts are not called correctly all the time, and not everyone is aware of when an alert is in effect. It is much simpler and less prone to error to prohibit burn barrels and outdoor burning devices entirely.

Page 57: Measure 46 review curtailment exemptions. The current Fairbanks curtailment exemption "These restrictions shall not apply during a power failure." should be reviewed to clarified that it only applies to homes reliant on electricity for heating. As currently written, it appears overly broad.

Page 68: Measure R7, Ban Use of Hydronic Heaters, incorrectly identifies that no other SIPs implemented the measure as rational for not evaluating.

Page 72: Measure R15 is technologically feasible.

Page 78: It may help to make a section break or Section 2 label for "Analysis of Marginal / Unquantifiable Benefit BACM Measures

Page 81-83: The discussion of Measure 6 may need additional documentation. Anecdotal evidence is that damping is common in Fairbanks and is potentially a bigger source of pollution than not having a damper at very cold conditions. If installation by a certified technician addresses this issue, that should be documented.

Page 84: The quote, "did not know if the rule had worked well" needs a reference. It is also not clear of how relevant that is. It could be implemented well in Fairbanks and the fact that it may not have worked well in another location does not make it technologically infeasible for this location.

Page 85-86: While qualitative assessments are helpful to provide context, a quantitative assessment will be necessary to evaluate the measures as BACM and MSM.

Page 88: There are references to Fairbanks in the conclusion for Measure 17, but the analysis refers to AAC code.

Page 89: There appears to be missing text in the Background section related to Method 9.

Page 91: Measure 23 could consider the solution that the decals could be reflective and would be seen by vehicle headlights. Measure 23 could also consider that the decals are used by neighbors to determine who is or is not in compliance. This may be helpful as citizen compliance assistance efforts could supplement the Borough enforcement program.

Page 98-100: Measure 40 needs to include a discussion of all the areas listed on page 22. In addition, if a date certain measure or if Measure 29 were instituted, Measure 40 would essentially be achieved.

Page 114: Measure R5 describes a similar rule in Utah but lists "none" under implementing jurisdictions. Please make consistent.

ULS Heating Oil

Page vii and Page 16: Please check your information on the percentage of households who have a central oil fired furnace. Please consult ADEC's contractor for the emissions inventory and home heating surveys about (1) the percentage of homes that heat only with an oil furnace, and (2) home with a central oil burner and a wood stove. We have seen different numbers than presented here.

Page 13: Please check the labels for Fairbanks HS #2 and Fairbanks HS #1. They may be switched.

Page 14: The statement that there is "a clear explanation" may not be correct, or at minimum is an overstatement. The difference in price between HS#1 and ULSD has varied over time, and the report did not include an explanation for the variations.

Page 14: The third paragraph assumes that the capital costs of shipping ULS would be more than exists today. However, all heating oil is shipped, regardless of sulfur content, and there is no justification for the report for why shipping ULS would be higher than for HS. Additionally, it is possible that the shipping cost per unit could go down marginally if only one product is being supplied to Fairbanks and/or if the quantity supplied increases.

Page 21: The text and Table 7 present inconsistent information. For instance, the text says that the discounted net-present value of scenario 2 is $10,232 while the table says it is $5,768.56.

THE STATE of ALASKA

GOVERNOR BILL WALKER

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September 13, 2018

Rich Morris
Directorate of Public Works-Environmental Division
U.S. Army Fort Wainwright
Attn. Richard Morris-Building 3023
1046 Marks Rd
Fort Wainwright, AK 99703

Subject: Request for additional information for the Best Available Control Technology Technical Memorandum for Fort Wainwright by November 1, 2018

Dear Mr. Morris:

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

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

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

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

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

Clean Air

to Mr. Eric Dick at Fort Wainwright on May 11, 2017 notifying him of the non-attainment area reclassification to Serious and included a request for the BACT analysis to be completed by August 8, 2017. The BACT analysis from Fort Wainwright, which included emission units found in Operating Permits AQ1121TVP02 Revision 2 and AQ0236TVP03 Revision 2, was submitted by email to the Department on July 13, 2017.

On March 22, 2018, ADEC released a preliminary draft of the BACT determination for Fort Wainwright for public discussion on its website at: http://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-serious-sip-development. As indicated in the release, this document is a work in progress. ADEC received additional information from Doyon Utilities and EPA on the preliminary draft BACT determination and expects to make changes to the determination based upon this input. Therefore, ADEC is requesting additional information from Fort Wainwright to assist it in making a legally and practicably enforceable BACT determination for the source.

Specifically, ADEC requests that Fort Wainwright review the cost effectiveness spreadsheet provided as a part of the preliminary SO_2 BACT determination which was originally developed by Sargent & Lundy (S&L) in 2010. The spreadsheet includes a link to the S&L white paper that provides a basis for the cost effectiveness calculations and indicates that the model is intended to calculate estimated total project cost (total capital cost of installation), as well as direct and indirect annual operating costs. These calculations are largely based on the estimated usage of sorbent and the gross generating capacity of the plant. Please use this spreadsheet to calculate the cost effectiveness of SO_2 removal in dollars per ton and identify all assumptions and technical justifications used in the analysis.

If ADEC does not receive a response to this information request by November 1, 2018, ADEC will make a preliminary BACT determination based upon the information originally provided. However, ADEC does not have the in depth knowledge of your facility's infrastructure and without additional information, may select a more stringent BACT for your facility in order to be approvable by EPA. It is ADEC's intent to release the preliminary BACT determinations for public review along with any precursor demonstrations and BACM analyses before the required public comment process for the Serious SIP. In order to provide this additional comment opportunity, ADEC must adhere to a strict schedule. Your assistance in providing the necessary information in a timely manner is greatly appreciated.

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

As indicated in a meeting on September 21, 2017 between ADEC Air Quality staff and the stationary sources affected by the BACT requirements, ADEC will also be using the information submitted or developed to support the BACT determinations for Most Stringent Measure (MSM)

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[4] https://www.gpo.gov/fdsys/pkg/USCODE-2013-title42/html/USCODE-2013-title42-chap85-subchapI-partD-subpart4-sec7513a

[5] 40. CFR 51.1010(4)

consideration. MSMs will be a required element of the state implementation plan if the State applies for an extension of the attainment date from EPA. Therefore, the information you submit will be used for both analyses.

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

Sincerely,

BY DB

Denise Koch, Director
Division of Air Quality

Enclosures:

September 10, 2018	ADEC Request for Additional Information for Fort Wainwright BACT Analysis
May 23, 2018	Doyon Utilities Comments Addressing the Preliminary Best Available Control Technology Determination for Fort Wainwright US Army Garrison and Doyon Utilities
May 21, 2018	EPA Comments on ADEC Preliminary Draft Serious SIP Development Materials for the Fairbanks Serious PM-2.5 nonattainment Area
October 20, 2017	Request for Additional Information for Fort Wainwright BACT Analysis;
May 11, 2017	Serious SIP BACT due date email
April 24, 2015	Voluntary BACT Analysis for Fort Wainwright (Privatized Emission Units) to Eric Dick, Environmental Manager US Army Fort Wainwright
April 24, 2015	Voluntary BACT Analysis for Fort Wainwright (Privatized Emission Units) to Kathleen Hook, Environmental Program Manager, Doyon Utilities, LLC

cc: Larry Hartig, ADEC/Commissioner's Office
Alice Edwards, ADEC/Commissioner's Office
Cindy Heil, ADEC/Air Quality
Deanna Huff, ADEC/Air Quality
Jim Plosay, ADEC/Air Quality
Aaron Simpson, ADEC/Air Quality
Eric Dick, U.S. Army (Fort Wainwright)
Tim Hamlin, EPA Region 10
Zach Hedgpeth, EPA Region 10
Dan Brown, EPA Region 10

ADEC Request for Additional Information
Fort Wainwright – Doyon Utilities
BACT Analysis Review
HydroGeoLogic, Inc. Report, June 2017

September 10, 2018

Please address the following comments by providing the additional information identified by November 1, 2018. Following the receipt of the information the Alaska Department of Environmental Conservation (ADEC) intends to make its preliminary Best Available Control Technology (BACT) determination and release that determination for public comment. In order to provide this additional comment opportunity, ADEC must adhere to a strict schedule. Your assistance in providing the necessary information in a timely manner is greatly appreciated. Additional requests for information may result from comments received during the public comment period or based upon the new information provided in response to this information request.

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

Draft Comments

1. Equipment Life – Page 4-2 of the analysis states "The BACT analysis for all control technologies assumes a 10-year useful life." ADEC identified that the EPA Air Pollution Control Cost Manual[1] (cost manual) uses a hypothetical example that assumes the control equipment has a useful life of ten years. However the cost analysis must use a reasonable estimate of the actual life of the control equipment for each control technology. As indicated in the proposed rule for Texas and Oklahoma Federal Implementation Plan for Regional Haze and Interstate Transport of Pollution Affecting Visibility – EPA-R06-OAR-2014-0754; Federal Register, Vol. 79, No. 241, 74818 [2] EPA indicated that:

   > "In determining the cost of scrubbers in our prior Oklahoma FIP, we used a lifetime of 30 years. In so doing, we noted that scrubber vendors indicate that the lifetime of a scrubber is equal to the lifetime of the boiler, which might easily be over 60 years. We also noted that many scrubbers that were installed between 1975 and 1986 are still in operation today (e.g., Coyote Station, H.L. Spurlock Unit 2, East Bend Unit 2, Laramie River Unit 3, Cholla 5, Basin Electric, Mitchell Unit 33, and all of the units in Table 30 that currently have scrubbers). Further, we noted that standard cost estimating handbooks and published papers report 30 years as a typical life for a scrubber and that many utilities routinely specify 30+ year lifetimes in requests for proposal and to evaluate proposals."

   In order to use an equipment life that is shorter than 30 years evidence must be provided to support the claim that "DU [Central Heat and Power Plant] is nearing the end of the useful design life cycle." This evidence could include information regarding the actual age of currently

[1] U.S. EPA OAQPS Air Pollution Control Cost Manual, 6th Edition [EPA/452/B-02-001]
[2] https://www.regulations.gov/document?D=EPA-R06-OAR-2014-0754-0001

operating control equipment, or design documents for associated process equipment such as boilers.

2. SNCR Cost Analysis – The EPA has recently updated the cost manual chapter pertaining to SNCR, and developed a cost spreadsheet to be used for evaluation of this technology for cost effectiveness. The cost analysis submitted as part of this BACT analysis[3] uses the EPA cost spreadsheet. Please update the cost analysis using the unrestricted potential to emit for each of the emissions units or propose operational limits (i.e., 300,000 tons of coal per year), and provide technical justifications for all assumptions used in the analysis submitted as part of the BACT analysis (i.e., direct and indirect contingency costs, startup costs, initial performance test costs, electricity rate, and reagent costs). Additionally, see Comments 7, 10, and 11 for additional information related to retrofit costs, baseline emissions, and factor of safety.

3. SCR Cost Analysis – The EPA has recently updated the cost manual chapter pertaining to SCR, and developed a cost spreadsheet to be used for evaluation of this technology for cost effectiveness. The cost analysis submitted as part of this BACT analysis[4] uses the EPA cost spreadsheet. Please update the cost analysis using the unrestricted potential to emit for each of the emissions units or propose operational limits, and provide technical justifications for all assumptions used in the analysis submitted as part of the BACT analysis (i.e., direct and indirect contingency costs, startup costs, initial performance test costs, electricity rate, and reagent costs). Additionally, see Comments 7, 10, and 11 for additional information related to retrofit costs, baseline emissions, and factor of safety.

4. BACT limits – BACT limits by definition, are numerical emission limits. However regulation allows a design, equipment, or work/operational practices if technological or economic limitations make a measurement methodology infeasible. Provide numerical emission limits (and averaging periods) for each proposed BACT selection, or justify why a measurement methodology is technically infeasible and provide the proposed design equipment, or work/operational practices for each pollutant and emission unit included in the analysis. Startup, Shutdown, and Malfunction (SSM) must be addressed in the BACT analysis. Measures to minimize the occurrence of these periods, or to minimize emissions during these periods are control options. Combinations of steady-state control options and SSM control options can be combined to create distinct control strategies. In no event shall application of BACT result in emissions of any pollutant which would exceed the emissions allowed by an applicable standard under 40 C.F.R. parts 60 (NSPS) and 61 (NESHAP).

   In comments from Doyon Utilities on May 23, 2018, they correctly identify that PM emissions from fuel-fired EUs are greater than actual PM-2.5 emissions from the same EU. They also requested clarification for the rationale for selecting a PM-2.5 emission rate of 0.05 grain/dscf. This value was provided in the June 2017 BACT Technical Memorandum from the U.S. Army Corp of Engineers. Therefore, please provide a basis for the 0.05 grain/dscf numerical BACT emissions limit for PM-2.5 emissions from the industrial coal fired boilers.

5. Good Combustion Practices – For each emission unit type (coal boilers, distillate boilers, engines, and material handling) for which good combustion practices was proposed as BACT, describe what constitutes good combustion practices. Include any work or operational practices that will be implemented and describe how continuous compliance with good combustion practices will be achieved.

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[3] "sncr_cost_manual_spreadsheet_2016_vf Ft Wainwright.xlsm"

[4] "scr_cost_manual_spreadsheet_2016_vf Ft Wainwright.xlsm"

6. Site-Specific Quotes Needed – The cost analyses must be based on emission unit-specific quotes for capital equipment purchase and installation costs at Fort Wainwright. This retrofit project must be considered in order to obtain reliable study/budget level (+/- 30%) cost estimates which are appropriate to use as the basis for decision making in determining BACT.

7. Retrofit Costs – EPA's Control Cost Manual indicates that study-level cost estimates (± 30 percent) should not include a retrofit factor greater than 30 percent, so detailed cost estimates (± 5 percent) are required for higher factors. High retrofit cost factors (50 percent or more) may be justified in unusual circumstances (e.g., long and unique ductwork and piping, site preparation, tight fits, helicopter or crane installation, additional engineering, and asbestos abatement). Provide detailed cost analyses and technical justification for difficult retrofit (1.6 – 1.9 times the capital costs) considerations used in the BACT analysis.

8. Condensable Particulate Matter – Although the existing control technology on the coal fired boilers may be evaluated as to whether it meets the requirement for BACT for particulate matter, baghouses primarily reduce emissions of filterable particulate matter rather than condensable PM. Given that all condensable PM emitted by the coal fired boilers would be classified as PM-2.5, the BACT analyses must include consideration of control options for these emissions. Where control technologies evaluated for control of other pollutants may provide a collateral benefit in reducing emissions of PM-2.5, this should be evaluated as well.

9. Interest Rate – All cost analyses must use the current bank prime interest rate. This can be found online at https://www.federalreserve.gov/releases/h15/ (go to bank prime rate in the table). Please revise the cost analyses as appropriate.

10. Baseline Emissions - Include the baseline emissions for each emission unit included in the analysis. Typically, the baseline emission rate represents a realistic scenario of upper bound uncontrolled emissions for the emissions unit (unrestricted potential to emit not actual emissions). NSPS and NESHAP requirements are not considered in calculating the baseline emissions. The baseline is usually the legal limit that would exist, but for the BACT determination. Baseline takes into account the effect of equipment that is part of the design of the unit (e.g., water injection and LNBs) because they are considered integral components to the unit's design. If the uncontrolled emission rate is 'soft,' run the cost effectiveness calculations using two or three different baselines.

11. Factor of Safety - If warranted, include a factor of safety when setting BACT emission limitations. The safety factor is a legitimate method of deriving a specific emission limitation that may not be exceeded. These limits do not have to reflect the highest possible control efficiencies, but rather, should allow the Permittee to achieve compliance with the numerical emission limit on a consistent basis.

12. Provide an economic analysis for low-NOx burners (LNBs) and flue gas recirculation (FGR) for one of the diesel-fired boilers, not proposed as limited operation (FWA EUs 8 – 10). Identify all small boilers with emission unit identification numbers. Provide technical justification for all assumptions used in the analysis submitted as part of the BACT analysis (i.e., direct and indirect contingency costs, startup costs, initial performance test costs, electricity rate, and reagent costs). Provide in the analysis: the control efficiency associated with LNBs and FGR, captured emissions (tons per year), emissions reduction (tons per year), capital costs (2017 dollars), operating costs (dollars per year), annualized costs (dollars per year), and cost effectiveness (dollars per ton) using EPA's cost manual.

13. Identify the control efficiencies proposed for limited operation of the small diesel-fired boilers (FWA EUs 8 – 10). If limited operation is not selected for the 24 other small boilers (list EU

numbers), identify the energy, environmental, economic impacts and other costs used to remove limited operation from the analysis. Include numerical NOx emission limits, work, or operational practices that will be implemented for the small boilers and describe how continuous compliance with the BACT limits will be achieved.

14. Identify control efficiencies for limited operation and installation of turbochargers and aftercoolers for diesel-fired engines to be used to rank the technically feasible control technologies. If the proposed control efficiencies of limited operation or installation of turbochargers and aftercoolers is greater than that of SCR, rank the control technologies to remove SCR from the top-down BACT analysis. If SCR is ranked as a higher control efficiency for reduction of NOx, provide justification as to why SCR can be removed from the analysis. If the engines only operate infrequently, as indicated in the analysis, provide a justification for why limited operation cannot be proposed as an enforceable limit, or provide an economic analysis that indicates that the cost effectiveness of installing SCR or turbochargers and aftercoolers would have an adverse economic impact. Please provide technical justifications for all assumptions used in the analysis submitted as part of the BACT analysis (i.e., direct and indirect contingency costs, startup costs, initial performance test costs, electricity rate, and reagent costs). Identify how many hours the units would have to operate for SCR to become economically feasible for these units.

15. Please propose numerical emission limits for the diesel-fired engines DU EUs 8 through 28, 30, 32 through 36, 29a, and 31a and FWA EUs 11, 12, 13, and 26 – 39. Provide the source of the emission factor (e.g., vendor data, AP-42 emission factor, EPA Tier Certified Engine, or NSPS Subpart IIII). Please identify what constitutes "good housekeeping practices" for DU EU 15 and describe how continuous compliance with these practices is BACT for the unit.

16. Include scrubbers and limited operation in the review of PM-2.5 control technologies for diesel-fired boilers. Rank the control technologies by efficiency (specify % control). Select the best performing control technology as BACT or provide specific energy, environmental, and economic impacts and other costs justification for why each better performing control technology was not selected instead of good combustion practices. Please provide technical justifications for all assumptions used in the analysis submitted as part of the BACT analysis (i.e., direct and indirect contingency costs, startup costs, initial performance test costs, electricity rate, and reagent costs). Provide a numerical PM-2.5 emission limit for the diesel-fired boilers or identify the work or operational practices that will be utilized to ensure compliance with proposed limits.

17. Include positive crankcase ventilation (closed crank ventilation system) and limited operation in the review of PM-2.5 control technologies for engines. Rank the control technologies (include low ash fuel) by efficiency (specify % control). Select the best performing control technology as BACT or provide specific energy, environmental, and economic impacts and other costs justification for why each better performing control technology was not selected instead of combustion of ULSD (low ash fuel). Revise the economic analysis for PM-2.5 emission controls for engines to reflect a calculation based on the units' potential to emit, not 500 hours per year (i.e., 8,760 hours per year or enforceable permit limits). Provide numerical PM-2.5 emission limits for the engines or identify the work or operational practices that will be utilized as BACT for the diesel-fired engines. Provide technical justifications for all assumptions used in the analysis submitted as part of the BACT analysis (i.e., direct and indirect contingency costs, startup costs, initial performance test costs, electricity rate, and reagent costs).

18. Provide an analysis of why enclosures are not technically feasible for the coal pile storage. Covering a stockpile is a proven control method used in pulverized mineral processing

operations. Additionally, provide an analysis of why wetting agents and watering for dust suppression are not considered technically feasible during the summer months (i.e., when the ambient temperature is above freezing). Provide a numerical PM-2.5 emission limit for the Emergency Coal Storage Pile and Operations or identify the work or operational practices that will be utilized as BACT for the material handling operations.

19. Department research has indicated that a switch to low ash and low sulfur fuels in large and small diesel engines can reduce emissions of particulate matter. Please provide an analysis of the expected control efficiency reduction over the federal emissions standards (baseline) expected to be achieved by switching to a low ash or low sulfur fuel.

20. Please provide manufacturer information for DU EU 9 identifying the PM-2.5 emission factor that will be used in setting the numerical BACT limits for that unit.

21. Provide an economic analysis for circulating dry scrubber (CDS) SO_2 technology for the coal fired boilers (EUs 1-6). Provide in the analysis: the control efficiency associated with CDS, captured emissions (tons per year), emissions reduction (tons per year), capital costs (2017 dollars), operating costs (dollars per year), annualized costs (dollars per year), and cost effectiveness (dollars per ton) using EPA's cost manual. Please provide technical justifications for all assumptions used in the analysis submitted as part of the BACT analysis (i.e., direct and indirect contingency costs, startup costs, initial performance test costs, electricity rate, and reagent costs).

22. Review the cost effectiveness spreadsheet provided as a part of the preliminary SO_2 BACT determination which was originally developed by Sargent & Lundy (S&L) in 2010. The spreadsheet includes a link to the S&L white paper that provides a basis for the cost effectiveness calculations and indicates that the model is intended to calculate estimated total project cost (total capital cost of installation), as well as direct and indirect annual operating costs. These calculations are largely based on the estimated usage of sorbent and the gross generating capacity of the plant. Please use this spreadsheet to calculate the cost effectiveness of SO_2 removal in dollars per ton and identify all assumptions and technical justifications used in the analysis. In this analysis use a bottom-up cost estimating approach based on actual plant conditions. These conditions would include SO_2 emission rates based on current PTE, permit constraints (where applicable and enforceable), available space, ambient conditions, and local factors such as construction logistics, labor wage rates, and local sorbent costs.

THE STATE of ALASKA
GOVERNOR BILL WALKER

Department of Environmental Conservation

DIVISION OF AIR QUALITY
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October 20, 2017

Rich Morris
Directorate of Public Works-Environmental Division
U.S. Army Fort Wainwright
Attn. Richard Morris-Building 3023
1046 Marks Rd
Fort Wainwright, AK 99703

Subject: Request for additional information for the Best Available Control Technology Technical Memorandum for Fort Wainwright by December 22, 2017

Dear Mr. Morris:

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

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

[1] Federal Register, Vol. 82, No. 89, Wednesday May 10, 2017 (https://dec.alaska.gov/air/anpms/comm/docs/2017-09391-CFR.pdf)
[2] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf, Clean Air Act 189 (b)(1)(B) and 189 (e) and CFR 51.1010(4)(i) require the implementation of BACT for point sources and precursors emissions and BACM for area sources.
[3] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf, Clean Air Act 189 (b)(1)(B) and 189 (e) require the implementation of BACT for point sources and precursors emissions and BACM for area sources

Clean Air

to Mr. Eric Dick at Fort Wainwright on May 11, 2017 notifying him of the reclassification to Serious and included a request for the BACT analysis to be completed by August 8, 2017. The BACT analysis from Fort Wainwright, which included emission units found in Operating Permits AQ1121TVP02 Revision 2 and AQ0236TVP03 Revision 2, was submitted by email to the Department on July 13, 2017.

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

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

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

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

Sincerely,

Denise Koch

Denise Koch, Director
Division of Air Quality

[4] https://www.gpo.gov/fdsys/pkg/USCODE-2013-title42/html/USCODE-2013-title42-chap85-subchapI-partD-subpart4-sec7513a

[5] 40. CFR 51.1010(4)

Enclosures:

October 20, 2017	Request for Additional Information for Fort Wainwright BACT Analysis;
May 11, 2017	Serious SIP BACT due date email
April 24, 2015	Voluntary BACT Analysis for Fort Wainwright (Privatized Emission Units) to Eric Dick, Environmental Manager US Army Fort Wainwright
April 24, 2015	Voluntary BACT Analysis for Fort Wainwright (Privatized Emission Units) to Kathleen Hook, Environmental Program Manager, Doyon Utilities, LLC

cc: Larry Hartig, ADEC/ Commissioner's Office
Alice Edwards, ADEC/ Commissioner's Office
Cindy Heil, ADEC/Air Quality
Deanna Huff, ADEC/ Air Quality
Jim Plosay, ADEC/ Air Quality
Aaron Simpson, ADEC/Air Quality
Eric Dick/U.S. Army (Fort Wainwright)
Tim Hamlin, EPA Region 10
Zach Hedgpeth, EPA Region 10

ADEC Request for Additional Information
Fort Wainwright – Doyon Utilities
BACT Analysis Review
HydroGeoLogic, Inc. Report, June 2017

October 20, 2017

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

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

Draft Comments

1. Equipment Life – Page 4-2 of the analysis states "The BACT analysis for all control technologies assumes a 10-year useful life." ADEC identified that the EPA Air Pollution Control Cost Manual[1] (cost manual) uses a hypothetical example that assumes the control equipment has a useful life of ten years. However the cost analysis must use a reasonable estimate of the actual life of the control equipment for each control technology. As indicated in the proposed rule for Texas and Oklahoma Federal Implementation Plan for Regional Haze and Interstate Transport of Pollution Affecting Visibility – EPA-R06-OAR-2014-0754; Federal Register, Vol. 79, No. 241, 74818 [2] EPA indicated that:

   > "In determining the cost of scrubbers in our prior Oklahoma FIP, we used a lifetime of 30 years. In so doing, we noted that scrubber vendors indicate that the lifetime of a scrubber is equal to the lifetime of the boiler, which might easily be over 60 years. We also noted that many scrubbers that were installed between 1975 and 1986 are still in operation today (e.g., Coyote Station, H.L. Spurlock Unit 2, East Bend Unit 2, Laramie River Unit 3, Cholla 5, Basin Electric, Mitchell Unit 33, and all of the units in Table 30 that currently have scrubbers). Further, we noted that standard cost estimating handbooks and published papers report 30 years as a typical life for a scrubber and that many utilities routinely specify 30+ year lifetimes in requests for proposal and to evaluate proposals."

   In order to use an equipment life that is shorter than 30 years evidence must be provided to support the claim that "DU [Central Heat and Power Plant] is nearing the end of the useful design life cycle." This evidence could include information regarding the actual age of currently

[1] U.S. EPA OAQPS Air Pollution Control Cost Manual, 6th Edition [EPA/452/B-02-001]
[2] https://www.regulations.gov/document?D=EPA-R06-OAR-2014-0754-0001

operating control equipment, or design documents for associated process equipment such as boilers.

2. DSI Cost Analysis – The cost manual does not currently include a chapter covering dry sorbent injection (DSI). However, as part of their Regional Haze FIP for Texas, EPA Region 6 developed cost estimates for DSI as applied to a large number of coal fired utility boilers. See the Technical Support Documents for the Cost of Controls Calculations for the Texas Regional Haze Federal Implementation Plan (Cost TSD) for additional information. The Cost TSD and associated spreadsheets are located at: https://www.regulations.gov/document?D=EPA-R06-OAR-2014-0754-0008. Please update the cost analysis for DSI and provide technical justifications for all assumptions used in the analysis submitted as part of the BACT analysis (i.e., direct and indirect contingency costs, startup costs, initial performance test costs, electricity rate, and reagent costs). Additionally, see Comments 7, 11, and 12 for additional information related to retrofit costs, baseline emissions, and factor of safety.

3. SNCR Cost Analysis – The EPA has recently updated the cost manual chapter pertaining to SNCR, and developed a cost spreadsheet to be used for evaluation of this technology for cost effectiveness. The cost analysis submitted as part of this BACT analysis[3] uses the EPA cost spreadsheet. Please update the cost analysis using the unrestricted potential to emit for each of the emissions units or propose operational limits (i.e., 300,000 tons of coal per year). Additionally, see Comments 7, 11, and 12 for additional information related to retrofit costs, baseline emissions, and factor of safety.

4. SCR Cost Analysis – The EPA has recently updated the cost manual chapter pertaining to SCR, and developed a cost spreadsheet to be used for evaluation of this technology for cost effectiveness. The cost analysis submitted as part of this BACT analysis[4] uses the EPA cost spreadsheet. Please update the cost analysis using the unrestricted potential to emit for each of the emissions units or propose operational limits. Additionally, see Comments 7, 11, and 12 for additional information related to retrofit costs, baseline emissions, and factor of safety.

5. BACT limits – BACT limits by definition, are numerical emission limits. However regulation allows a design, equipment, or work/operational practices if technological or economic limitations make a measurement methodology infeasible. Provide numerical emission limits (and averaging periods) for each proposed BACT selection, or justify why a measurement methodology is technically infeasible and provide the proposed design equipment, or work/operational practices for pollutant for each emission unit included in the analysis. Startup, Shutdown, and Malfunction (SSM) must be addressed in the BACT analysis. Measures to minimize the occurrence of these periods, or to minimize emissions during these periods are control options. Combinations of steady-state control options and SSM control options can be combined to create distinct control strategies. In no event shall application of BACT result in emissions of any pollutant which would exceed the emissions allowed by an applicable standard under 40 C.F.R. parts 60 (NSPS) and 61 (NESHAP).

6. Good Combustion Practices –For each emission unit type (coal boilers, distillate boilers, engines, and material handling) for which good combustion practices was proposed as BACT, describe what constitutes good combustion practices. Include any work or operational practices that will be implemented and describe how continuous compliance with good combustion practices will be achieved.

[3] "sncr_cost_manual_spreadsheet_2016_vf Ft Wainwright.xlsm"
[4] "scr_cost_manual_spreadsheet_2016_vf Ft Wainwright.xlsm"

7. Retrofit Costs – EPA's Control Cost Manual indicates that study-level cost estimates (± 30 percent) should not include a retrofit factor greater than 30 percent, so detailed cost estimates (± 5 percent) is required for higher factors. High retrofit cost factors (50 percent or more) may be justified in unusual circumstances (e.g., long and unique ductwork and piping, site preparation, tight fits, helicopter or crane installation, additional engineering, and asbestos abatement). Provide detailed cost analyses and justification for difficult retrofit (1.6 – 1.9 times the capital costs) considerations used in the BACT analysis.
8. Provide an economic analysis for low-NOx burners (LNBs) and flue gas recirculation (FGR) for one of the diesel-fired boilers, not proposed as limited operation (FWA EUs 8 – 10). Identify all small boilers with emission unit identification numbers. Provide in the analysis: the control efficiency associated with LNBs and FGR, Captured Emissions (tons per year), Emissions Reduction (tons per year), Capital Costs (2017 dollars), Operating Costs (dollars per year), Annualized Costs (dollars per year), and Cost Effectiveness (dollars per ton) using EPA's cost manual.
9. Identify the control efficiencies proposed for limited operation of the small diesel-fired boilers (FWA EUs 8 – 10). If limited operation is not selected for the 24 other small boilers (list EU ID numbers), identify the energy, environmental, economic impacts and other costs used to remove limited operation from the analysis. Include numerical NOx emission limits, work, or operational practices that will be implemented for the small boilers and describe how continuous compliance with the BACT limits will be achieved.
10. Identify control efficiencies for limited operation and installation of turbochargers and aftercoolers for diesel-fired engines to be used to rank the technically feasible control technologies. If the proposed control efficiencies of limited operation or installation of turbochargers and aftercoolers is greater than that of SCR, rank the control technologies to remove SCR from the top-down BACT analysis. If SCR is ranked as a higher control efficiency for reduction of NOx, provide justification as to why SCR can be removed from the analysis. If the engines only operate infrequently, as indicated in the analysis, provide a justification for why limited operation cannot be proposed as an enforceable limit, or provide an economic analysis that indicates that the cost effectiveness of installing SCR or turbochargers and aftercoolers would have an adverse economic impact. Identify how many hours the units would have to operate for SCR to become economically feasible for these units.
11. Include the baseline emissions for all emission units included in the analysis. Typically, the baseline emission rate represents a realistic scenario of upper bound uncontrolled emissions for the emissions unit (unrestricted potential to emit not actual emissions). NSPS and NESHAP requirements are not considered in calculating the baseline emissions. The baseline is usually the legal limit that would exist, but for the BACT determination. Baseline takes into account the effect of equipment that is part of the design of the unit (e.g., water injection and LNBs) because they are considered integral components to the unit's design. If the uncontrolled emission rate is 'soft,' run the cost effectiveness calculations using two or three different baselines.
12. If warranted, include a factor of safety when setting BACT emission limitations. The safety factor is a legitimate method of deriving a specific emission limitation that may not be exceeded. These limits do not have to reflect the highest possible control efficiencies, but rather, should allow the Permittee to achieve compliance with the numerical emission limit on a consistent basis.

13. Please propose numerical emission limits for the diesel-fired engines DU EUs 8 through 28, 30, 32 through 36, 29a, and 31a and FWA EUs 11, 12, 13, and 26 – 39. Provide the source of the emission factor (e.g., vendor data, AP-42 emission factor, EPA Tier Certified Engine, or NSPS Subpart IIII). Please identify what constitutes "good housekeeping practices" for DU EU 15 and describe how continuous compliance with these practices is BACT for the unit.
14. Include scrubbers and limited operation in the review of PM-2.5 control technologies for diesel-fired boilers. Rank the control technologies by efficiency (specify % control). Select the best performing control technology as BACT or provide specific energy, environmental, and economic impacts and other costs justification for why each better performing control technology was not selected instead of good combustion practices. Provide a numerical PM-2.5 emission limit for the diesel-fired boilers or identify the work or operational practices that will be utilized to ensure compliance with proposed limits.
15. Include positive crankcase ventilation (closed crank ventilation system) and limited operation in the review of PM-2.5 control technologies for engines. Rank the control technologies (include low ash fuel) by efficiency (specify % control). Select the best performing control technology as BACT or provide specific energy, environmental, and economic impacts and other costs justification for why each better performing control technology was not selected instead of combustion of ULSD (low ash fuel). Revise the economic analysis for PM-2.5 emission controls for engines to reflect a calculation based on the units' potential to emit, not 500 hours per year (i.e., 8,760 hours per year or enforceable permit limits). Provide numerical PM-2.5 emission limits for the engines or identify the work or operational practices that will be utilized as BACT for the diesel-fired engines.
16. Provide an analysis of why enclosures are not technically feasible for the coal pile storage. Covering a stockpile is a proven control method used in pulverized mineral processing operations. Additionally, provide an analysis of why wetting agents and watering for dust suppression is not considered technically feasible during the summer months (i.e., when the ambient temperature is above freezing). Provide a numerical PM-2.5 emission limit for the Emergency Coal Storage Pile and Operations or identify the work or operational practices that will be utilized as BACT for the material handling operations.

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April 24, 2015

Eric Dick, Environmental Manager
U.S. Army Fort Wainwright
ATTN: IMFW-PWE (E. Dick)
1060 Gaffney Road, # 4500
Fort Wainwright, AK 99703-4500

Subject: Voluntary BACT Analysis for Fort Wainwright (Privatized Emission Units)

Dear Mr. Dick:

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

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

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

Background

Clean Air

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

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

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

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

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

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

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

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

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

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

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

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

Sincerely,

Denise Koch, Director
Division of Air Quality

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

THE STATE of ALASKA
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April 24, 2015

Kathleen Hook
Environmental Program Manager
Doyon Utilities, LLC
PO Box 74040
Fairbanks, AK 99707

Subject: Voluntary BACT Analysis for Fort Wainwright (Privatized Emission Units)

Dear Ms. Hook:

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

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

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

Background

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

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

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

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

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

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

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

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

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

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

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

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

Sincerely,

Denise Koch, Director
Division of Air Quality

cc: Larry Hartig, ADEC/ Commissioner's Office
Alice Edwards, ADEC/ Commissioner's Office
John Kuterbach, ADEC/ Air Quality
Cindy Heil, ADEC/Air Quality
Deanna Huff, ADEC/ Air Quality
Eric Dick/U.S. Army (Fort Wainwright)

THE STATE of ALASKA
GOVERNOR BILL WALKER

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DIVISION OF AIR QUALITY
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Return Receipt Requested

September 13, 2018

Rich Morris
Directorate of Public Works-Environmental Division
U.S. Army Fort Wainwright
Attn. Richard Morris-Building 3023
1046 Marks Rd
Fort Wainwright, AK 99703

Subject: Request for additional information for the Best Available Control Technology Technical Memorandum for Fort Wainwright by November 1, 2018

Dear Mr. Morris:

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

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

[1] Federal Register, Vol. 82, No. 89, Wednesday May 10, 2017 (https://dec.alaska.gov/air/anpms/comm/docs/2017-09391-CFR.pdf)
[2] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf, Clean Air Act 189 (b)(1)(B) and 189 (e) and CFR 51.1010(4)(i) require the implementation of BACT for point sources and precursors emissions and BACM for area sources.
[3] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf, Clean Air Act 189 (b)(1)(B) and 189 (e) require the implementation of BACT for point sources and precursors emissions and BACM for area sources

Clean Air

to Mr. Eric Dick at Fort Wainwright on May 11, 2017 notifying him of the non-attainment area reclassification to Serious and included a request for the BACT analysis to be completed by August 8, 2017. The BACT analysis from Fort Wainwright, which included emission units found in Operating Permits AQ1121TVP02 Revision 2 and AQ0236TVP03 Revision 2, was submitted by email to the Department on July 13, 2017.

On March 22, 2018, ADEC released a preliminary draft of the BACT determination for Fort Wainwright for public discussion on its website at: http://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-serious-sip-development. As indicated in the release, this document is a work in progress. ADEC received additional information from Doyon Utilities and EPA on the preliminary draft BACT determination and expects to make changes to the determination based upon this input. Therefore, ADEC is requesting additional information from Fort Wainwright to assist it in making a legally and practicably enforceable BACT determination for the source.

Specifically, ADEC requests that Fort Wainwright review the cost effectiveness spreadsheet provided as a part of the preliminary SO_2 BACT determination which was originally developed by Sargent & Lundy (S&L) in 2010. The spreadsheet includes a link to the S&L white paper that provides a basis for the cost effectiveness calculations and indicates that the model is intended to calculate estimated total project cost (total capital cost of installation), as well as direct and indirect annual operating costs. These calculations are largely based on the estimated usage of sorbent and the gross generating capacity of the plant. Please use this spreadsheet to calculate the cost effectiveness of SO_2 removal in dollars per ton and identify all assumptions and technical justifications used in the analysis.

If ADEC does not receive a response to this information request by November 1, 2018, ADEC will make a preliminary BACT determination based upon the information originally provided. However, ADEC does not have the in depth knowledge of your facility's infrastructure and without additional information, may select a more stringent BACT for your facility in order to be approvable by EPA. It is ADEC's intent to release the preliminary BACT determinations for public review along with any precursor demonstrations and BACM analyses before the required public comment process for the Serious SIP. In order to provide this additional comment opportunity, ADEC must adhere to a strict schedule. Your assistance in providing the necessary information in a timely manner is greatly appreciated.

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

As indicated in a meeting on September 21, 2017 between ADEC Air Quality staff and the stationary sources affected by the BACT requirements, ADEC will also be using the information submitted or developed to support the BACT determinations for Most Stringent Measure (MSM)

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[4] https://www.gpo.gov/fdsys/pkg/USCODE-2013-title42/html/USCODE-2013-title42-chap85-subchapI-partD-subpart4-sec7513a

[5] 40. CFR 51.1010(4)

consideration. MSMs will be a required element of the state implementation plan if the State applies for an extension of the attainment date from EPA. Therefore, the information you submit will be used for both analyses.

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

Sincerely,

Denise Koch, Director
Division of Air Quality

Enclosures:

September 10, 2018	ADEC Request for Additional Information for Fort Wainwright BACT Analysis
May 23, 2018	Doyon Utilities Comments Addressing the Preliminary Best Available Control Technology Determination for Fort Wainwright US Army Garrison and Doyon Utilities
May 21, 2018	EPA Comments on ADEC Preliminary Draft Serious SIP Development Materials for the Fairbanks Serious PM-2.5 nonattainment Area
October 20, 2017	Request for Additional Information for Fort Wainwright BACT Analysis;
May 11, 2017	Serious SIP BACT due date email
April 24, 2015	Voluntary BACT Analysis for Fort Wainwright (Privatized Emission Units) to Eric Dick, Environmental Manager US Army Fort Wainwright
April 24, 2015	Voluntary BACT Analysis for Fort Wainwright (Privatized Emission Units) to Kathleen Hook, Environmental Program Manager, Doyon Utilities, LLC

cc: Larry Hartig, ADEC/Commissioner's Office
Alice Edwards, ADEC/Commissioner's Office
Cindy Heil, ADEC/Air Quality
Deanna Huff, ADEC/Air Quality
Jim Plosay, ADEC/Air Quality
Aaron Simpson, ADEC/Air Quality
Eric Dick, U.S. Army (Fort Wainwright)
Tim Hamlin, EPA Region 10
Zach Hedgpeth, EPA Region 10
Dan Brown, EPA Region 10

ADEC Request for Additional Information
Fort Wainwright – Doyon Utilities
BACT Analysis Review
HydroGeoLogic, Inc. Report, June 2017

September 10, 2018

Please address the following comments by providing the additional information identified by November 1, 2018. Following the receipt of the information the Alaska Department of Environmental Conservation (ADEC) intends to make its preliminary Best Available Control Technology (BACT) determination and release that determination for public comment. In order to provide this additional comment opportunity, ADEC must adhere to a strict schedule. Your assistance in providing the necessary information in a timely manner is greatly appreciated. Additional requests for information may result from comments received during the public comment period or based upon the new information provided in response to this information request.

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

Draft Comments

1. Equipment Life – Page 4-2 of the analysis states "The BACT analysis for all control technologies assumes a 10-year useful life." ADEC identified that the EPA Air Pollution Control Cost Manual[1] (cost manual) uses a hypothetical example that assumes the control equipment has a useful life of ten years. However the cost analysis must use a reasonable estimate of the actual life of the control equipment for each control technology. As indicated in the proposed rule for Texas and Oklahoma Federal Implementation Plan for Regional Haze and Interstate Transport of Pollution Affecting Visibility – EPA-R06-OAR-2014-0754; Federal Register, Vol. 79, No. 241, 74818 [2] EPA indicated that:

   > "In determining the cost of scrubbers in our prior Oklahoma FIP, we used a lifetime of 30 years. In so doing, we noted that scrubber vendors indicate that the lifetime of a scrubber is equal to the lifetime of the boiler, which might easily be over 60 years. We also noted that many scrubbers that were installed between 1975 and 1986 are still in operation today (e.g., Coyote Station, H.L. Spurlock Unit 2, East Bend Unit 2, Laramie River Unit 3, Cholla 5, Basin Electric, Mitchell Unit 33, and all of the units in Table 30 that currently have scrubbers). Further, we noted that standard cost estimating handbooks and published papers report 30 years as a typical life for a scrubber and that many utilities routinely specify 30+ year lifetimes in requests for proposal and to evaluate proposals."

   In order to use an equipment life that is shorter than 30 years evidence must be provided to support the claim that "DU [Central Heat and Power Plant] is nearing the end of the useful design life cycle." This evidence could include information regarding the actual age of currently

[1] U.S. EPA OAQPS Air Pollution Control Cost Manual, 6th Edition [EPA/452/B-02-001]
[2] https://www.regulations.gov/document?D=EPA-R06-OAR-2014-0754-0001

operating control equipment, or design documents for associated process equipment such as boilers.

2. <u>SNCR Cost Analysis</u> – The EPA has recently updated the cost manual chapter pertaining to SNCR, and developed a cost spreadsheet to be used for evaluation of this technology for cost effectiveness. The cost analysis submitted as part of this BACT analysis[3] uses the EPA cost spreadsheet. Please update the cost analysis using the unrestricted potential to emit for each of the emissions units or propose operational limits (i.e., 300,000 tons of coal per year), and provide technical justifications for all assumptions used in the analysis submitted as part of the BACT analysis (i.e., direct and indirect contingency costs, startup costs, initial performance test costs, electricity rate, and reagent costs). Additionally, see Comments 7, 10, and 11 for additional information related to retrofit costs, baseline emissions, and factor of safety.

3. <u>SCR Cost Analysis</u> – The EPA has recently updated the cost manual chapter pertaining to SCR, and developed a cost spreadsheet to be used for evaluation of this technology for cost effectiveness. The cost analysis submitted as part of this BACT analysis[4] uses the EPA cost spreadsheet. Please update the cost analysis using the unrestricted potential to emit for each of the emissions units or propose operational limits, and provide technical justifications for all assumptions used in the analysis submitted as part of the BACT analysis (i.e., direct and indirect contingency costs, startup costs, initial performance test costs, electricity rate, and reagent costs). Additionally, see Comments 7, 10, and 11 for additional information related to retrofit costs, baseline emissions, and factor of safety.

4. <u>BACT limits</u> – BACT limits by definition, are numerical emission limits. However regulation allows a design, equipment, or work/operational practices if technological or economic limitations make a measurement methodology infeasible. Provide numerical emission limits (and averaging periods) for each proposed BACT selection, or justify why a measurement methodology is technically infeasible and provide the proposed design equipment, or work/operational practices for each pollutant and emission unit included in the analysis. Startup, Shutdown, and Malfunction (SSM) must be addressed in the BACT analysis. Measures to minimize the occurrence of these periods, or to minimize emissions during these periods are control options. Combinations of steady-state control options and SSM control options can be combined to create distinct control strategies. In no event shall application of BACT result in emissions of any pollutant which would exceed the emissions allowed by an applicable standard under 40 C.F.R. parts 60 (NSPS) and 61 (NESHAP).

   In comments from Doyon Utilities on May 23, 2018, they correctly identify that PM emissions from fuel-fired EUs are greater than actual PM-2.5 emissions from the same EU. They also requested clarification for the rationale for selecting a PM-2.5 emission rate of 0.05 grain/dscf. This value was provided in the June 2017 BACT Technical Memorandum from the U.S. Army Corp of Engineers. Therefore, please provide a basis for the 0.05 grain/dscf numerical BACT emissions limit for PM-2.5 emissions from the industrial coal fired boilers.

5. <u>Good Combustion Practices</u> – For each emission unit type (coal boilers, distillate boilers, engines, and material handling) for which good combustion practices was proposed as BACT, describe what constitutes good combustion practices. Include any work or operational practices that will be implemented and describe how continuous compliance with good combustion practices will be achieved.

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[3] "sncr_cost_manual_spreadsheet_2016_vf Ft Wainwright.xlsm"
[4] "scr_cost_manual_spreadsheet_2016_vf Ft Wainwright.xlsm"

6. Site-Specific Quotes Needed – The cost analyses must be based on emission unit-specific quotes for capital equipment purchase and installation costs at Fort Wainwright. This retrofit project must be considered in order to obtain reliable study/budget level (+/- 30%) cost estimates which are appropriate to use as the basis for decision making in determining BACT.

7. Retrofit Costs – EPA's Control Cost Manual indicates that study-level cost estimates (± 30 percent) should not include a retrofit factor greater than 30 percent, so detailed cost estimates (± 5 percent) are required for higher factors. High retrofit cost factors (50 percent or more) may be justified in unusual circumstances (e.g., long and unique ductwork and piping, site preparation, tight fits, helicopter or crane installation, additional engineering, and asbestos abatement). Provide detailed cost analyses and technical justification for difficult retrofit (1.6 – 1.9 times the capital costs) considerations used in the BACT analysis.

8. Condensable Particulate Matter – Although the existing control technology on the coal fired boilers may be evaluated as to whether it meets the requirement for BACT for particulate matter, baghouses primarily reduce emissions of filterable particulate matter rather than condensable PM. Given that all condensable PM emitted by the coal fired boilers would be classified as PM-2.5, the BACT analyses must include consideration of control options for these emissions. Where control technologies evaluated for control of other pollutants may provide a collateral benefit in reducing emissions of PM-2.5, this should be evaluated as well.

9. Interest Rate – All cost analyses must use the current bank prime interest rate. This can be found online at https://www.federalreserve.gov/releases/h15/ (go to bank prime rate in the table). Please revise the cost analyses as appropriate.

10. Baseline Emissions - Include the baseline emissions for each emission unit included in the analysis. Typically, the baseline emission rate represents a realistic scenario of upper bound uncontrolled emissions for the emissions unit (unrestricted potential to emit not actual emissions). NSPS and NESHAP requirements are not considered in calculating the baseline emissions. The baseline is usually the legal limit that would exist, but for the BACT determination. Baseline takes into account the effect of equipment that is part of the design of the unit (e.g., water injection and LNBs) because they are considered integral components to the unit's design. If the uncontrolled emission rate is 'soft,' run the cost effectiveness calculations using two or three different baselines.

11. Factor of Safety - If warranted, include a factor of safety when setting BACT emission limitations. The safety factor is a legitimate method of deriving a specific emission limitation that may not be exceeded. These limits do not have to reflect the highest possible control efficiencies, but rather, should allow the Permittee to achieve compliance with the numerical emission limit on a consistent basis.

12. Provide an economic analysis for low-NOx burners (LNBs) and flue gas recirculation (FGR) for one of the diesel-fired boilers, not proposed as limited operation (FWA EUs 8 – 10). Identify all small boilers with emission unit identification numbers. Provide technical justification for all assumptions used in the analysis submitted as part of the BACT analysis (i.e., direct and indirect contingency costs, startup costs, initial performance test costs, electricity rate, and reagent costs). Provide in the analysis: the control efficiency associated with LNBs and FGR, captured emissions (tons per year), emissions reduction (tons per year), capital costs (2017 dollars), operating costs (dollars per year), annualized costs (dollars per year), and cost effectiveness (dollars per ton) using EPA's cost manual.

13. Identify the control efficiencies proposed for limited operation of the small diesel-fired boilers (FWA EUs 8 – 10). If limited operation is not selected for the 24 other small boilers (list EU

numbers), identify the energy, environmental, economic impacts and other costs used to remove limited operation from the analysis. Include numerical NOx emission limits, work, or operational practices that will be implemented for the small boilers and describe how continuous compliance with the BACT limits will be achieved.

14. Identify control efficiencies for limited operation and installation of turbochargers and aftercoolers for diesel-fired engines to be used to rank the technically feasible control technologies. If the proposed control efficiencies of limited operation or installation of turbochargers and aftercoolers is greater than that of SCR, rank the control technologies to remove SCR from the top-down BACT analysis. If SCR is ranked as a higher control efficiency for reduction of NOx, provide justification as to why SCR can be removed from the analysis. If the engines only operate infrequently, as indicated in the analysis, provide a justification for why limited operation cannot be proposed as an enforceable limit, or provide an economic analysis that indicates that the cost effectiveness of installing SCR or turbochargers and aftercoolers would have an adverse economic impact. Please provide technical justifications for all assumptions used in the analysis submitted as part of the BACT analysis (i.e., direct and indirect contingency costs, startup costs, initial performance test costs, electricity rate, and reagent costs). Identify how many hours the units would have to operate for SCR to become economically feasible for these units.

15. Please propose numerical emission limits for the diesel-fired engines DU EUs 8 through 28, 30, 32 through 36, 29a, and 31a and FWA EUs 11, 12, 13, and 26 – 39. Provide the source of the emission factor (e.g., vendor data, AP-42 emission factor, EPA Tier Certified Engine, or NSPS Subpart IIII). Please identify what constitutes "good housekeeping practices" for DU EU 15 and describe how continuous compliance with these practices is BACT for the unit.

16. Include scrubbers and limited operation in the review of PM-2.5 control technologies for diesel-fired boilers. Rank the control technologies by efficiency (specify % control). Select the best performing control technology as BACT or provide specific energy, environmental, and economic impacts and other costs justification for why each better performing control technology was not selected instead of good combustion practices. Please provide technical justifications for all assumptions used in the analysis submitted as part of the BACT analysis (i.e., direct and indirect contingency costs, startup costs, initial performance test costs, electricity rate, and reagent costs). Provide a numerical PM-2.5 emission limit for the diesel-fired boilers or identify the work or operational practices that will be utilized to ensure compliance with proposed limits.

17. Include positive crankcase ventilation (closed crank ventilation system) and limited operation in the review of PM-2.5 control technologies for engines. Rank the control technologies (include low ash fuel) by efficiency (specify % control). Select the best performing control technology as BACT or provide specific energy, environmental, and economic impacts and other costs justification for why each better performing control technology was not selected instead of combustion of ULSD (low ash fuel). Revise the economic analysis for PM-2.5 emission controls for engines to reflect a calculation based on the units' potential to emit, not 500 hours per year (i.e., 8,760 hours per year or enforceable permit limits). Provide numerical PM-2.5 emission limits for the engines or identify the work or operational practices that will be utilized as BACT for the diesel-fired engines. Provide technical justifications for all assumptions used in the analysis submitted as part of the BACT analysis (i.e., direct and indirect contingency costs, startup costs, initial performance test costs, electricity rate, and reagent costs).

18. Provide an analysis of why enclosures are not technically feasible for the coal pile storage. Covering a stockpile is a proven control method used in pulverized mineral processing

operations. Additionally, provide an analysis of why wetting agents and watering for dust suppression are not considered technically feasible during the summer months (i.e., when the ambient temperature is above freezing). Provide a numerical PM-2.5 emission limit for the Emergency Coal Storage Pile and Operations or identify the work or operational practices that will be utilized as BACT for the material handling operations.

19. Department research has indicated that a switch to low ash and low sulfur fuels in large and small diesel engines can reduce emissions of particulate matter. Please provide an analysis of the expected control efficiency reduction over the federal emissions standards (baseline) expected to be achieved by switching to a low ash or low sulfur fuel.

20. Please provide manufacturer information for DU EU 9 identifying the PM-2.5 emission factor that will be used in setting the numerical BACT limits for that unit.

21. Provide an economic analysis for circulating dry scrubber (CDS) SO_2 technology for the coal fired boilers (EUs 1-6). Provide in the analysis: the control efficiency associated with CDS, captured emissions (tons per year), emissions reduction (tons per year), capital costs (2017 dollars), operating costs (dollars per year), annualized costs (dollars per year), and cost effectiveness (dollars per ton) using EPA's cost manual. Please provide technical justifications for all assumptions used in the analysis submitted as part of the BACT analysis (i.e., direct and indirect contingency costs, startup costs, initial performance test costs, electricity rate, and reagent costs).

22. Review the cost effectiveness spreadsheet provided as a part of the preliminary SO_2 BACT determination which was originally developed by Sargent & Lundy (S&L) in 2010. The spreadsheet includes a link to the S&L white paper that provides a basis for the cost effectiveness calculations and indicates that the model is intended to calculate estimated total project cost (total capital cost of installation), as well as direct and indirect annual operating costs. These calculations are largely based on the estimated usage of sorbent and the gross generating capacity of the plant. Please use this spreadsheet to calculate the cost effectiveness of SO_2 removal in dollars per ton and identify all assumptions and technical justifications used in the analysis. In this analysis use a bottom-up cost estimating approach based on actual plant conditions. These conditions would include SO_2 emission rates based on current PTE, permit constraints (where applicable and enforceable), available space, ambient conditions, and local factors such as construction logistics, labor wage rates, and local sorbent costs.

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DOYON UTILITIES LLC

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PO Box 74040
Fairbanks, AK 99707

May 23, 2018

Mr. Aaron Simpson
Alaska Department of Environmental Conservation
Division of Air Quality
P.O Box 111800
Juneau AK 99811-1800

Re: Comments Addressing the Preliminary Best Available Control Technology Determination for Fort Wainwright US Army Garrison and Doyon Utilities

Dear Mr. Simpson:

Doyon Utilities, LLC (DU) is providing the enclosed comments addressing the preliminary Best Available Control Technology (BACT) assessment that the Alaska Department of Environmental Conservation (ADEC) has prepared for the Fort Wainwright US Army Garrison and Doyon Utilities. DU has limited this review and comment effort to those emissions units that are operated by DU and that are included in Title V Permit AQ1121TVP02, Revision 2. DU has not provided comments addressing emissions units that are operated by the US Army Garrison.

DU appreciates this opportunity to provide comments addressing the preliminary BACT documents. DU understands that the preliminary BACT documents are a work in progress. DU also understands that ADEC hopes to receive additional information from the public as a result of the release of the preliminary draft BACT documents and that ADEC expects to make changes to the documents based upon this input.

The attached comments identify a number of concerns of varying degree of seriousness. The items discussed in the comments that are of most concern to DU are:

- The preliminary BACT analysis for sulfur dioxide (SO_2) emissions from the Central Heat and Power Plant (CHPP) boilers (Emissions Units (EUs) 1 through 6) identifies dry sorbent injection (DSI) as the preferred SO_2 emission control technology. The analysis that supports this determination is based on unsupported assumptions, use of a cost model that may not be appropriate for these boilers, and inconsistent SO_2 emission calculations. The analysis is also lacking site-specific engineering data. As a result, the analysis appears not to be defensible.
- The preliminary BACT analysis for SO_2 emissions from the CHPP boilers assumes a more stringent coal combustion limit and coal sulfur content than currently required, but does

not assess these options through the five-step BACT process or determine whether these assumptions are even valid.

- The preliminary $PM_{2.5}$ BACT analysis and draft BACT determinations for the material handling emissions units (EUs 7a, 7b, 7c, 51a, 51b, and 52) are confusing and unclear.
- The required methods to demonstrate compliance with the preliminary BACT limits are in many cases unclear or unspecified.
- Many of the preliminary $PM_{2.5}$ BACT emission limits are provided without supporting rationale, may not be appropriate as $PM_{2.5}$ emission limits, and/or may not be achievable.

Please contact Kathleen Hook at 907-455-1540 or khook@doyonutilities.com if you have any questions or would like to further discuss any specific comments.

Best Regards,

Shayne Coiley
Senior Vice President
Doyon Utilities, LLC

cc: Jim Plosay, ADEC
Kathleen Hook, DU
Courtney Kimball, SLR

Enclosure: Comments Addressing the Preliminary Best Available Control Technology Determination for Fort Wainwright US Army Garrison and Doyon Utilities Dated March 22, 2018

CO 18-061

Comments Addressing the Preliminary Best Available Control Technology Determination for Fort Wainwright US Army Garrison and Doyon Utilities Dated March 22, 2018

General Comments

1. Inadequate technical information is provided in the Preliminary Best Available Control Technology Determination (Preliminary Determination). This lack of information generally includes, but is not limited to, the following areas.
   - Little or no engineering data or rationale is provided to support the Alaska Department of Environmental Conservation (ADEC) preliminary determinations addressing whether an emission control technology is or is not technically feasible.
   - Little or no engineering data, cost data, or rationale is provided to support the preliminary determinations addressing whether an emission control technology is or is not Best Available Control Technology (BACT).
   - The methodology used to determine emissions reductions is typically not quantified.

   This lack of data and rationale is inconsistent with past ADEC insistence that the stationary sources provide a substantial level of detail and specific engineering data to support the BACT analyses that the stationary sources submitted to ADEC.

2. The Preliminary Determination tables that provide a comparison of emissions unit capacities and BACT emission limits for affected stationary sources (University of Alaska Fairbanks, Fort Wainwright, Golden Valley Electric Association (GVEA) North Pole Plant, and GVEA Zehnder Plant) generally have inconsistent units of measurement within each table. As a result, these tables have limited usefulness without further analysis being prepared.

3. In many cases, the Preliminary Determination does not identify the methods that must be used to verify compliance with the preliminary BACT limits. The methods to be used for verifying compliance should be identified so that the Permittees can determine whether the methods that ADEC intends to require are appropriate and whether the methods will be overly cumbersome and/or expensive.

Section 3. BACT Determination for Nitrogen Oxides (NO_X)

In Section 3 of the Preliminary Determination, ADEC states that "the NO_X controls proposed in this section are not planned to be implemented." Instead, ADEC is planning to submit a final precursor demonstration to the U.S. Environmental Protection Agency (EPA) "as justification not to require NO_X controls." As a result, Doyon Utilities (DU) has not reviewed this section of the Preliminary Determination and is not providing comments because:

- ADEC does not plan to implement the proposed NO_X BACT determinations, and
- Focusing on those sections of the Preliminary Determination that ADEC intends to implement is a better use of the short amount of time that was made available for this review.

DU will review any future NO_X BACT proposals and will provide comments if EPA does not approve the ADEC final precursor demonstration and the implementation of NO_X BACT emissions controls becomes mandatory.

Section 4. BACT Determination for Fine Fraction Respirable Particulate Matter ($PM_{2.5}$)

The ADEC preliminary $PM_{2.5}$ BACT analysis includes errors, assumptions, and inconsistencies that are of varying degree of concern. Each instance of concern is discussed below in no particular order of seriousness.

4. Section 4: The term "full steam baghouse" appears several times in the Preliminary Determination. The correct term is "full stream baghouse."

5. Section 4.1 (Industrial Coal-fired Boilers), Steps 4(b) and 5(b): The Preliminary Determination establishes a $PM_{2.5}$ emission limit of 0.05 grains per dry standard cubic foot (gr/dscf) for the coal-fired boilers, Emissions Units (EUs) 1 through 6. No basis for the selection of this $PM_{2.5}$ emission rate is provided, but the selected emission rate value is consistent with the particulate matter (PM) emission rate for industrial processes and fuel burning equipment established in 18 Alaska Administrative Code (AAC) 50.055(b)(1). This PM emission limit is commonly called the SIP PM emission limit. The appropriateness of using the SIP PM emission limit to establish a $PM_{2.5}$ emission limit is unclear because:
   - PM includes all filterable particulate matter regardless of size while $PM_{2.5}$ includes only filterable particulate matter with an nominal aerodynamic diameter of 2.5 microns, and
   - $PM_{2.5}$ includes all condensable matter while PM does not include any condensable matter.

   In many, but not all cases, actual PM emissions from a fuel-fired emissions unit are greater than the actual $PM_{2.5}$ emissions from that same emissions unit. If the assumption is being made that $PM_{2.5}$ emissions from EUs 1 through 6 are less than or equal to PM emissions, this assumption should be supported with existing source test results to confirm that compliance with the preliminary limit can be met. If this assumption is not being made, ADEC should explain more fully the rationale for selecting a $PM_{2.5}$ emission rate of 0.05 gr/dscf as the $PM_{2.5}$ BACT emission limit for EUs 1 through 6.

6. Section 4.1 (Industrial Coal-fired Boilers), Table 4-2: This table provides the total plant capacity for the listed stationary sources instead of individual boiler capacity. The preliminary $PM_{2.5}$ BACT emission limits are not presented in consistent units of measurement or are not provided in the table. As a result, the table is not useful for the intended comparative purpose.

7. Section 4.3 (Large Diesel-fired Engines), Step 1(f): This section cites "RBLC NO_X determinations." The correct reference is "RBLC information for $PM_{2.5}$ determinations."

8. Section 4.3 (Large Diesel-fired Engines), Steps 1 through 5: The ADEC rationale for the preliminary BACT determination of combusting ultra-low sulfur diesel (ULSD) is inconsistent for the following reasons.

- In Step 1(d), the use of low sulfur fuel is listed as an available and feasible emission control technology.
- Step 2 eliminates low sulfur fuel as technically infeasible which is inconsistent with the statement in Step 1 and incorrect. The use of low sulfur fuel is technically feasible, but the contribution of this technology toward reducing $PM_{2.5}$ emissions cannot be quantified.
- Step 3 does not address the use of ULSD.
- Step 5 requires the use of ULSD, with no supporting rationale or cost analysis. This determination is also inconsistent with the incorrect Step 2 conclusion that low sulfur fuel is not technically feasible.

Please make the appropriate corrections to Section 4.3. DU understands that the requirement to combust ULSD will likely remain unchanged for the large diesel-fired engines. Specifically, the preliminary sulfur dioxide (SO_2) BACT decision also requires the use of ULSD, so correcting this inconsistency in Section 4.3 will not eliminate the requirement to combust ULSD in the large diesel-fired engines. The combustion of ULSD is required in the large diesel-fired engines that are subject to 40 Code of Federal Regulations (CFR) 60 Subpart IIII.

9. Section 4.3 (Large Diesel-fired Engines), Step 4 and 5: A cost analysis is not provided to support the preliminary $PM_{2.5}$ BACT determinations identified in Step 5. Because each BACT determination must be based on technical and economic feasibility, the rationale for these preliminary determinations is incomplete, making the validity of the preliminary determinations questionable. Please provide the required economic feasibility analysis.

10. Section 4.3 (Large Diesel-fired Engines), Step 5(b): The Preliminary Determination is unclear with respect to whether the 500 hours per year operating limit in non-emergency situations is applicable to EUs 8, 10, 11, 13, and 15 individually or cumulatively. If the operating limit is cumulative, the limit is inconsistent with Title V Permit AQ1121TVP02 which allows EU 8 to be converted to a non-emergency engine with a limit of 500 hours per year. If the limit applies to each individual engine, the requirement is inconsistent with applicable requirements under 40 CFR 63 Subpart ZZZZ (or Subpart IIII, if applicable), which allows 100 hours per year of non-emergency operation but does not restrict those non-emergency operations to maintenance checks and readiness testing.

11. Section 4.3 (Large Diesel-fired Engines), Table 4-6: This table cites manufacturer information for establishing the preliminary $PM_{2.5}$ BACT limit of 0.09 grams per horsepower-hour (g/hp-hr) for EU 15. The source of this manufacturer information is not provided in the Preliminary Determination and cannot otherwise be obtained to confirm this $PM_{2.5}$ emission rate is correct. An emission rate of 0.09 g/hp-hr is equivalent to 0.0002 pounds per horsepower-hour (lb/hp-hr). Potential emissions of $PM_{2.5}$ for EU 15 are currently calculated using an emission factor of 0.0007 lb/hp-hr per AP-42, Table 3.4-1. As a result, the preliminary BACT $PM_{2.5}$ limit of 0.09 g/hp-hr may not be appropriate or achievable for EU 15. Please provide the manufacturer information stating that a $PM_{2.5}$ emission rate of 0.09 g/hp-hr has been established for EU 15.

12. Section 4.4 (Small Emergency Engines), Step 5(a): The requirement to limit non-emergency operation of each of EUs 9, 12, 14, 16 through 28, 29a, 30, 31a, and 32 through 36 to 500 hours per year is

inconsistent with applicable requirements under 40 CFR 63 Subpart ZZZZ (or Subpart IIII, if applicable), which allows 100 hours per year of non-emergency operation but does not restrict those non-emergency operations to maintenance checks and readiness testing.

13. Section 4.4 (Small Diesel-fired Engines), Steps 1 through 5: The ADEC rationale for the preliminary BACT determination of combusting ultra-low sulfur diesel (ULSD) is inconsistent for the following reasons.
    - In Step 1(d), the use of low sulfur fuel is listed as an available and technically feasible emission control technology.
    - Step 2 eliminates low sulfur fuel as technically infeasible which is inconsistent with the statement in Step 1 and incorrect. The use of low sulfur fuel is technically feasible, but the contribution of this technology toward reducing $PM_{2.5}$ emissions cannot be quantified.
    - Step 3 does not address the use of ULSD.
    - Step 5 requires the use of ULSD, with no supporting rationale or cost analysis. This determination is also inconsistent with the incorrect Step 2 conclusion that low sulfur fuel is not technically feasible.

    Please make the appropriate corrections to Section 4.4. DU understands that the requirement to combust ULSD will likely remain unchanged for the small diesel-fired engines. Specifically, the preliminary sulfur dioxide (SO_2) BACT decision also requires the use of ULSD, so correcting this inconsistency in Section 4.4 will not eliminate the requirement to combust ULSD in the small diesel-fired engines.

14. Section 4.4 (Small Diesel-fired Engines), Steps 4 and 5: A cost analysis is not provided to support the preliminary $PM_{2.5}$ BACT determinations identified in Step 5. Because each BACT determination must be based on technical and economic feasibility, the rationale for these preliminary determinations is incomplete, making the validity of the preliminary determinations questionable. Please provide the required economic feasibility.

15. Section 4.4 (Small Diesel-fired Engines), Table 4-9: The proposed preliminary $PM_{2.5}$ BACT limit of 7.21 E-04 pounds per horsepower-hour (lb/hp-hr) is the PM_{10} emission factor for gasoline-fired engines from Table 3.3-1 of AP-42. Using this emission factor is not appropriate for diesel-fired engines or for $PM_{2.5}$.

16. Section 4.5 (Material Handling): This section addresses the material handling emissions units (EUs 7a through 7c, 51a, 51b, and 52) but does not make a distinction between the material handling emissions units that can be equipped with fabric filter controls (EUs 7a through 7c, 51a, and 51b) and the emissions unit that cannot be equipped with a baghouse (EU 52, the emergency coal storage pile) Because a coal storage pile is a very different type of emissions unit, the section is not clear with respect to the types of emission control technologies that might be used for each listed emissions unit. As a result, EU 52 should be addressed separately for clarity.

    As an example of this confusion, Step 1(g) indicates that wind screens are not considered technically feasible for material handling units, but Step 2 states that all identified control technologies are technically feasible. Wind screens may be an available and/or technically feasible control technology for a coal storage pile, but not necessarily for a dust collector. Conversely, fabric filters are identified as available and technically feasible in Step 1(a), but fabric filters are not an available control technology for coal storage piles.

17. Section 4.5 (Material Handling), Table 4-12: The proposed preliminary $PM_{2.5}$ BACT for EU 7c, the North Coal Handling Dust Collector, includes a 200 hours per year (hr/yr) operating limit. This emissions unit is a backup coal handling system that is used if the primary system coal handling system is not available. The Preliminary Determination does not explain the basis for this BACT operating limit. Pleased fully explain the rationale for imposing a BACT operating limit of 200 hr/yr on EU 7c.

18. Section 4.5 (Material Handling), Steps 4(e) and 5(c): The preliminary proposed $PM_{2.5}$ BACT emission limit of 0.48 tons per year (tpy) for EU 52 is 34 percent of the existing $PM_{2.5}$ potential to emit of 1.42 tpy. The Preliminary Determination does not provide the basis for the 0.48 tpy $PM_{2.5}$ BACT emission limit or explain the emission limit calculation methodology. Please fully explain the basis and rationale for imposing a $PM_{2.5}$ BACT emission limit of 0.48 tpy on EU 52.

19. Section 4.5 (Material Handling), Table 4-12: This table includes columns labeled “Current Controls” and “Current Emission Factors.” The table does not provide preliminary proposed $PM_{2.5}$ BACT emission limits, which is inconsistent with the Table 4-12 title of “PM-2.5 BACT Control Technologies Proposed for Material Handling.”

Section 5. BACT Determination for SO_2

The Preliminary Determination SO_2 BACT analysis includes errors, assumptions, and inconsistencies that are of varying degree of concern. These concerns are discussed below in no particular order of seriousness.

20. Section 5.1 (Industrial Coal-fired Boilers): In Table 5.3, the Preliminary Determination specifies SO_2 cost effectiveness for wet scrubbing and spray dry absorbers to be \$10,788 per ton SO_2 removed and \$11,136 per ton SO_2 removed, respectively. Although not explicitly stated, the Preliminary Determination implies that these two technologies are not economically feasible and so are not SO_2 BACT. While the economically feasibility analyses for these two control technologies likely underestimate actual costs, DU agrees that wet scrubbing and spray dry absorbers are not SO_2 BACT. As a result, comments addressing wet scrubbing or spray dry absorbers are not presented in this document.

    The preliminary proposed SO_2 BACT is dry sorbent injection (DSI) which the Preliminary Determination states has a cost effectiveness of \$6,435 per ton SO_2 removed. This cost effectiveness determination is questionable and likely too low for the reasons provided below. Note that developing an accurate cost effectiveness for DSI would require a bottom-up cost estimate based on actual plant conditions.

- Cost Model Validity: The cost effectiveness spreadsheet provided by ADEC as a part of the preliminary SO_2 BACT determination was originally developed by Sargent & Lundy (S&L) in 2010. The spreadsheet includes a link to the S&L white paper that provides a basis for the calculations that are in Row 25 of the spreadsheet. The S&L white paper states that the model is intended to calculate estimated Total Project Cost (total capital cost of installation), as well as direct and indirect annual operating costs. These calculations are largely based on the estimated usage of sorbent (in this case Trona) on a tons per hour (tph) basis and the gross generating capacity of the plant. The white paper omits information that is necessary to ensure that the spreadsheet is properly applied to a specific situation, including:
  - Types of plants to which the model is applicable (utility power generation, combined heat and power (CHP), cogeneration, other);
  - Applicable number of boilers (single unit or multi-boiler installation);
  - Applicable size range;
  - Equipment included in the Total Purchased Cost (TPC) calculation;
  - On-site bulk storage capacity;
  - A basis for selecting a "Retrofit factor" other than "1.0"; and
  - Data and other information used to develop and support the equations used in the spreadsheet.

  Based on review of the cost effectiveness model and the supporting documentation, determining the validity of the results of the analysis is not possible. The concerns are rooted in three assumptions made by ADEC in preparing the cost model
  - ADEC assumed that the model is valid for a plant the size of Fort Wainwright.
    - The calculation for "Base Module" cost (Row 30 of the spreadsheet) is based on an equation that uses the predicted sorbent demand. The S&L white paper states that the equation was developed based on "Cost data for several DSI systems." No references or supporting information relating to these projects were provided. While the validity range for the equation was not identified, one piece of information that gives some indication of the applicable range. The equation has a discontinuity at 25 tph of sorbent flow. Given that the predicted total sorbent flow for all six coal-fired boilers at Fort Wainwright is 1.5 tph (based on the estimate in the Preliminary Determination), the Fort Wainwright boilers would be at the very bottom of the range of potential plant sizes. Without additional data to justify the cost calculation at very low sorbent injection rates, determining if the results of the equation are accurate is very difficult.
  - The Preliminary Determination assumes that multiple boilers can accurately be modeled as a lumped heat input in a single spreadsheet.
    - The S&L white paper does not identify the type or configuration of the plant on which the calculation was based. Data input fields included in the spreadsheet (unit size, gross heat rate) indicate that the analysis was developed based on a single power generation unit (single boiler, single steam turbine, no CHP or cogeneration).
    - Based on the inputs to the spreadsheet provided by ADEC, EUs 1 thorough 6 are being treated as a single, lumped heat input value. This approach is an oversimplification and will not accurately account for the equipment and utilities that will be necessary to independently operate six boilers. The actual installation will require six separate trains of sorbent processing and transport equipment. Each train contains a day bin, mills,

feeders, blowers, coolers, hoppers, piping, instrumentation, controls, electrical wiring and other supporting equipment. This need for separate systems complicates the design, increases overall footprint, and reduces the economy of scale that might be realized with a single larger unit. In theory, ADEC could possibly use the Retrofit Factor to account for this additional complexity, but without a method for determining the correct Retrofit Factor value, selecting any value other than “1.0” would be pure conjecture.

  - The sorbent feed rate currently calculated for EUs 1 through 6 is very small. Should the model be revised to calculate the cost effectiveness on a per unit basis, the feed rate would be roughly one sixth of the current value. This change would further amplify concerns about the accuracy of the TPC calculation.

- ADEC assumed that the model is valid for a heat and power plant.
  - As discussed above, no information is available addressing the type of plant on which the S&L spreadsheet is based. The assumption is that the plant is a single power generation unit. A CHP plant differs significantly from a “traditional” power plant in that the steam produced in a CHP plant is not exclusively used to generate electricity. In an effort to make the spreadsheet work for this application, ADEC used “dummy” data in the “Unit Size (Gross)” and “Gross Heat Rate” fields so that the calculated “Heat Input” field showed the maximum heat input value for EUs 1 through 6 (1,380 million British thermal units per hour (MMBtu/hr)). This approach has unintended consequences relating to the accuracy of the direct annual costs. The fixed and variable operating and maintenance (O&M) costs are evaluated on a per kilowatt and a per megawatt basis respectively. Utilizing a “dummy” gross generation number to calculate annual costs may not produce an accurate result. Based on review, no method exists to accurately model the direct annual costs for an installation such as the Fort Wainwright EUs 1 through 6 by using the S&L spreadsheet.
  - The average maximum hourly heat input identified in Row 15 of the spreadsheet is incorrect. The value shown reflects the maximum hourly heat input for each of the boiler. The value does not account for the permitted annual coal consumption limit. If the coal consumption limit is considered, the maximum hourly heat input is reduced to 583 MMBtu/hr averaged over a year. A reduction in hourly heat input will have an impact on the overall cost effectiveness calculation, but given the concerns with the calculation itself, identifying the specific impacts is difficult.

- SO_2 Emission Rates: The preliminary BACT determination states that the SO_2 emission rate used in the spreadsheet to calculate the total annualized operating costs was based on 0.2 weight percent (wt. pct.) sulfur coal and AP-42 emission factors. This approach resulted in an emission rate of 0.46 pounds of SO_2 per MMBtu (lb SO_2/MMBtu) heat input. This value is significantly different than the effective emission rate for the plant based on the PTE established in Title V Permit AQ1121TVP02, Revision 2. The effective emission rate is calculated as follows:

  Permitted PTE: 1,764 tons of SO_2
  Permitted coal consumption limit: 336,000 tpy
  Assumed coal energy content: 7,600 British thermal units per pound (Btu/lb)

1,764 tons SO_2/yr * 1 year/336,000 tons coal * 1 lb coal/7,600 Btu * 10^6 Btu/MMBtu * 1 ton coal/2,000 lb coal * 2,000 lb SO_2/ton
= 0.691 lb SO_2/MMBtu

The difference between the ADEC-assumed emission rate and the effective emission rate leads to a significant error in the SO_2 cost effectiveness calculation. The ADEC spreadsheet divides the total annualized cost (determined by using the 0.46 lb/MMBtu SO_2 rate) by the SO_2 PTE (with an effective rate of 0.691 lb/MMBtu). The use of two different emission rates in this calculation results in an invalid comparison of two values that should not be compared to each other. For the result of the equation to be valid, the total annualized cost must be calculated using an SO_2 emission rate equal to the SO_2 PTE.

- Conclusion: Based on the review of the preliminary SO_2 BACT determination and the associated cost effectiveness calculation, no indication could be found that the Preliminary Determination calculation accurately reflects the actual operating conditions for EUs 1 through 6. As a result, no basis exists for determining if the installation of a DSI system is or is not economically feasible. Despite the inability to determine the accuracy of the calculations in the Preliminary Determination, those calculations likely underestimate the DSI cost effectiveness because the Preliminary Determination underestimates SO_2 emissions on a lb/MMBtu basis.

  If a more accurate cost effectiveness is to be determined, the cost effectiveness should be recalculated using a bottom-up cost estimating approach based on actual plant conditions. These conditions would include SO_2 emission rates based on current PTE, permit constraints (where applicable and enforceable), available space, ambient conditions, and local factors such as construction logistics, labor wage rates, and local sorbent costs.

21. Section 5.1 (Industrial Coal-fired Boilers), Step 5: The proposed coal combustion limit of 300,000 tpy and the assumption that the coal sulfur content is no greater than 0.2 weight percent are not evaluated through the five-step BACT process, or even identified as available control technologies in Step 1.
    - The current coal combustion limit for the six boilers is 336,000 tpy, per Condition 12.1 of AQ1121TVP02, Revision 2.
    - The current coal sulfur content is not limited beyond the State SIP SO_2 standard and the requirement to determine what the SO_2 emission concentrations would be prior to combusting coal with a sulfur content of greater than 0.4 weight percent. (Refer to Conditions 11 and 11.1 of AQ1121TVP02, Revision 2.)
    - If either of these requirements is to be imposed as a limit without a BACT analysis justifying the limit, the limit(s) should be used to calculate a revised baseline emission rate. The BACT analysis should then calculate any further emission reductions based on that revised baseline emission rate.

    DU does not agree that either the coal consumption limit of 300,000 tpy or the coal sulfur content assumption of less than or equal to 0.2 weight percent is appropriate. More investigation is needed to determine whether these assumptions are valid and feasible. At the least, the 0.2 weight percent coal sulfur limit should be assessed through the BACT analysis process. DU is not aware that Usibelli Coal Mine, the sole supplier of coal in Alaska, has even been contacted to advise whether the mine is capable of providing coal meeting that specification on a long-term basis. Step 1(d) of the Preliminary Determination acknowledges that the current contract guarantee is less than 0.4 weight percent sulfur, and that the coal typically ranges from 0.08 to 0.28 weight percent sulfur.

22. Section 5.4 (Small Emergency Engines), Step 5(a): The requirement to limit non-emergency operation of small emergency engines is inconsistent with applicable requirements under 40 CFR 63 Subpart ZZZZ (or Subpart IIII, if applicable), which allows 100 hours per year of non-emergency operation but does not restrict those non-emergency operations to maintenance checks and readiness testing.

23. Section 5.4 (Small Emergency Engines), Step 5(b): The determination that good combustion practices is BACT should be eliminated or a rationale should be provided for selecting good combustion practices in addition to the combustion of ULSD and limited operations. Per Table 5-10 of the Preliminary Determination, good combustion practices were not determined to be SO_2 BACT for small diesel-fired engines at other stationary sources. While DU follows good combustion practices as a standard practice, Step 3(c) indicates that good combustion practices are the least effective SO_2 emission control technology.

Attachment: EPA comments on ADEC Preliminary Draft Serious SIP Development materials for the Fairbanks serious $PM_{2.5}$ nonattainment area

General

The attached comments are intended to provide guidance on the preliminary drafts of SIP documents in development by ADEC. We expect that there will be further opportunities to review the more complete versions of the drafts and intend to provide more detailed comments at that point

1. Statutory Requirements - This preliminary draft does not address all statutory requirements laid out in Title I, Part D of the Clean Air Act or 40 C.F.R. Part 51, Subpart Z. The submitted Serious Area SIP will need to address all statutory and regulatory requirements as identified in Title I, Part D of the Clean Air Act, 40 C.F.R. Part 51, Subpart Z, the August 24, 2016 $PM_{2.5}$ SIP Requirements Rules (81 FR 58010, also referred to at the $PM_{2.5}$ Implementation Rule), and any associated guidance.

   In the preliminary drafts, notable missing elements included: Reasonable Further Progress, Quantitative Milestones, and Conformity. This is not an exhaustive list of required elements.

   The NNSR program is a required element for the serious area SIP. We understand ADEC recently adopted rule changes to address the nonattainment new source review element of the Serious SIP, and that ADEC plans to submit them to the EPA separately in October 2018. Thank you for your work on this important plan element.

2. Extension Request - This preliminary draft does not address the decision to request an attainment date extension and the associated impracticability demonstration. On September 15, 2017, ADEC sent a letter notifying the EPA that it intends to apply for an extension of the attainment date for the Fairbanks $PM_{2.5}$ Serious nonattainment area. The Serious Area SIP submitted to EPA will need to include both an extension request and an impracticability demonstration that meet the requirements of Clean Air Act section 188(e). In order to process an extension request, the EPA requests timely submittal of your Serious Area SIP to allow for sufficient time to review and take action prior to the current December 2019 attainment date, so as to allow, if approvable, the extension of the attainment date as requested/appropriate. For additional guidance, please refer to 81 FR 58096.

3. Split Request - We support the ADEC and the FNSB's decision to suspend their request to the EPA to split the nonattainment area. We support the effort to site a monitor in the Fairbanks area that is more representative of neighborhood conditions and thus more protective of community health. This would provide additional information on progress towards achieving clean air throughout the nonattainment area.

4. BACM (and BACT), and MSM - Best Available Control Measures (including Best Available Control Technologies) and Most Stringent Measures are evaluative processes inclusive of steps to identify, adopt, and implement control measures. Their definitions are found in 51.1000, 51.1010(a).

All source categories, point sources – area sources – on-road sources – non-road sources, need to be evaluated for BACM/BACT and MSM. De minimis or minimal contribution are not an allowable rationale for not evaluating or selecting a control measure or technology.

The process for identifying and adopting MSM is separate from, yet builds upon, the process of selecting BACM. Given that Alaska is intent on applying for an extension to the attainment date, Alaska must identify BACM and MSM for all source categories. These processes are described in 51.1010(a) and 51.1010(b) and in the $PM_{2.5}$ Implementation Rule preamble at 81 FR 58080 and 58096. We further discuss this process in the "BACM (and BACT), MSM" section that starts on page 3 below.

5. Resources and Implementation - The serious area $PM_{2.5}$ attainment plan will be best able to achieves its objectives when all components of the SIP, both the ADEC statewide and FNSB local measures, are sufficiently funded and fully implemented.

6. Use of Consultants- For the purpose of clarity, it will be important to identify that while contractors are providing support to ADEC, all analyses are the responsibility of the State.

Emissions Inventory

1. Extension Request Emission Inventories - Emissions inventories associated with the attainment date extension request will need to be developed and submitted. Table 1 of the Emissions Inventory document is one example where the submittal will need to include the additional emissions inventories, including RFP inventories, extension year inventories for planning and modeling, and attainment year planning and modeling inventories, associated with the attainment date extension request.

2. Modeling Requirements - Related to emissions inventory requirements, the serious area SIP will need to model and inventory 2023 and 2024, at minimum. We recommend starting at 2024 and modeling earlier and earlier until there is a year where attainment is not possible. That would satisfy the requirement that attainment be reached as soon as practicable.

3. Condensable Emissions - All emissions inventories and any associated planning, such as Reasonable Further Progress schedules, need to include condensable emissions as a separate column or line item, where available. Where condensable emissions are not available separately, provide condensable emissions as included (and noted as such) in the total number. The following are examples of where this would need to be incorporated in to the Emissions Inventory document:
   a. Page 20, paragraph 5 (or 2nd from the bottom).
   b. Page 34, Table 8. Include templates.

<u>Precursor Demonstration</u>

1. <u>Ammonia Precursor Demonstration</u> - The draft Concepts and Approaches document, Table 4 on page 9, states that a precursor demonstration was completed for ammonia and that the result was "Not significant for either point sources or comprehensively." The Precursor Demonstration chapter does not include an analysis for ammonia. Please include the precursor demonstration for ammonia in the Serious Plan or amend this table.

2. <u>Sulfur Dioxide Precursor Description</u> - The draft Concepts and Approaches document, Table 4 on page 9, states that sulfur dioxide was found to be significant. All precursors are presumptively considered significant by default and the precursor demonstration can only show that controls on a precursor are not required for attainment. Suggested language is, "No precursor demonstration possible."

<u>BACM (and BACT), MSM</u>

Overall

The EPA appreciates ADECs efforts to identify and evaluate BACM for eventual incorporation into the Serious Area SIP. The documents clearly display significant effort on the part of the state and are a good first step in the SIP development process. In particular, we are supportive of ADECs efforts to evaluate BACT for the major stationary sources in the nonattainment area, as control of these sources is required by the CAA and $PM_{2.5}$ SIP Requirements Rule.

1. <u>BACM/BACT and MSM: Separate Analyses</u> - The "Possible Concepts and Potential Approaches" document appears to conflate the terms BACM/BACT and MSM, as well as, the analyses for determining BACM/BACT and MSM. BACM and MSM have separate definitions in 40 CFR 51.1000. By extension, the processes for selecting BACM and MSM are laid out separately in the $PM_{2.5}$ SIP Requirements Rule (compare 40 CFR 51.1010(a) for BACM and 40 CFR 51.1010(b) for MSM). Accordingly, the serious area SIP submission will need to have both a BACM/BACT analysis and an MSM analysis. We believe that there is flexibility in how these analyses can be presented, so long as the submission clearly satisfies the requirements of both evaluations, methodologies, and findings.

2. <u>Selection of Measures and Technologies</u> - The CAA and the $PM_{2.5}$ SIP Requirements Rule requires that ***<u>all</u>*** available control measures and technologies that meet the BACM (including BACT) and MSM criteria need to be implemented. All source categories need to be evaluated including: point sources (including non-major sources), area sources, on-road sources, and non-road sources.

3. <u>Technological Feasibility</u> - All available control measures and technologies include those that have been implemented in nonattainment areas or attainment areas, or those potential measures and technologies that are available or new but not yet implemented. Similarly, Alaska may not automatically eliminate a particular control measure because other sources or nonattainment areas have not implemented the measure. The regulations do not have a quantitative limit on number of controls that should be implemented.

For technological feasibility, a state may consider factors including local circumstances, the condition and extent of needed infrastructure, or population size or workforce type and habits, which may prohibit certain potential control measures from being implementable. However, in the instance where a given control measure has been applied in another NAAQS nonattainment area, the state will need to provide a detailed justification for rejecting any potential BACM or MSM measure as technologically infeasible (81 FR 58085).

A Borough referendum prohibiting regulation of home heating would not be an acceptable consideration to render potential measures technologically infeasible. The State would be responsible for implementing the regulations in the case that the Borough was not able. We believe that the most efficient path to clean air in the Borough is through a local, community effort.

4. Economic Feasibility - The BACM (including BACT) and MSM analyses need to identify the basis for determining economic feasibility for both the BACM and MSM analyses. In general, the $PM_{2.5}$ SIP Requirements Rule requires the state apply more stringent criteria for determining the feasibility of potential MSM than that used to determine the feasibility of BACM and BACT, including consideration of higher cost/ton values as cost effective.

5. Timing - The evaluations will need to identify the time for selection, adoption, and implementation for all measures. BACT must be selected, adopted, and implemented no later than 4 years after reclassification (June 2021). MSM must be selected, adopted, and implemented no later than 1 year prior to the potentially extended attainment date (December 2023 at latest). The RFP section of the serious area plan will need to identify the BACM and MSM control measures, their time of implementation, and the time(s) of expected emissions reductions. Timing delays in selection, adoption, implementation are not considered for BACM and MSM.

   As mentioned in the comment above in the "General" comment section, there are three criteria distinguishing between BACM and MSM, not one.

BACM - General

1. BACM definition, evaluations - The definition of BACM at 40 CFR 51.1000 describes BACM as any measure "that generally can achieve greater permanent and enforceable emissions reductions in direct $PM_{2.5}$ and/or $PM_{2.5}$ plan precursors from sources in the area than can be achieved through the implementation of RACM on the same sources." We believe that potential measures that are no more stringent than existing measures already implemented in FNSB, those that do not provide additional direct $PM_{2.5}$ and/or $PM_{2.5}$ precursors emissions reductions, do not meet the definition of BACM. These would need to be evaluated in the BACM and MSM analysis.

   For measures that are currently being implemented in Fairbanks that provide equivalent or more stringent control, we recommend identifying the ADEC or Borough implemented measure as part of the BACM control strategy. These implemented measures should be listed in their BACM findings at the end of the document. This comment applies to all of the measures that were screened out from consideration due to not being more stringent than the already implemented measure.

The analyses for a number of measures (e.g., Measure 30, Distribution of Curtailment Program information at time of woodstove sale) conclude that the emission reductions would be insignificant and difficult to quantify and, therefore, the measure is not technologically feasible. These measures may be technologically feasible. However, if existing measures constitute a higher level of control or if implementation of the measures is economically infeasible those would be valid conclusions if properly documented. De minimis or minimal contribution is not a valid rationale for not considering or selecting a control measure or technology.

The conclusion "not eligible for consideration as BACM" is not valid as all assessments for BACM and MSM are part of the evaluation. More appropriate conclusions could include that existing measures qualify as BACM or MSM, or are more stringent. Additional conclusions could include that evaluated measures were not technologically feasible, economically feasible, or could not practically be adopted and implemented prior to the required timeframe for BACM or MSM.

2. BACM and MSM, Ammonia - In the Approaches and Concepts document, Table 5 references that there are no applicable control measures or technologies for the $PM_{2.5}$ precursor ammonia. No information to substantiate this claim are found in the preliminary draft documents. Unless NH_3 is demonstrated to be insignificant for this area, the serious area plan will need to include an evaluation of NH_3 and potential controls for all source categories including points sources.

3. Backsliding Potential - When benchmarking the BACM and MSM analyses for stringency, ensure that the evaluation is based on the measures approved into the current Moderate SIP. This will relate primarily to the current ADEC/FNSB curtailment program but also other related rules. Many wood smoke control measures are interrelated, and changes to those measures may affect determinations on stringency of directly related and indirectly related measures. Examples of this can be found in multiple measures including, but not limited to Measures 5, 7, and 16.

4. Transportation Control Measures - The Approaches and Concepts document, on Page 13, states that the MOVES2014 model does not estimate a PM benefit as a result of an I/M program, and therefore the I/M is not technologically feasible. This is not a valid conclusion given that the Fairbanks area operated an I/M program to reduce carbon monoxide and the Utah Cache Valley nonattainment areas has an I/M program for VOC control. This measure will need to be evaluated. Referring to the 110(l) analysis for the Fairbanks CO I/M program may provide insight into how to quantify the emissions associated with an I/M program.

With regard to control measures related to on-road sources, we have received inquiries from the community regarding idling vehicles and further evaluation emission benefits would be responsive to citizen concern and may provide additional air quality benefit.

BACM - Specific Measures

- Measure 16, page 34-35. Date certain Removal of Uncertified Devices. The "date certain" removal of uncertified woodstoves in Tacoma, Washington appears more stringent than the current Moderate SIP approved Fairbanks ordinance in terms of the regulation and in practice. While the current ordinance appears to provide similar protection during stage 1 alerts, this is dependent on 100% compliance and the curtailment program remaining in its current form. Removal of uncertified stoves guarantees reductions in emissions in the airshed during both the curtailment periods and throughout the heating season. The information provided does not support the conclusion that the Fairbanks controls provides equivalent or more stringent control. Date certain removal of uncertified wood stoves needs to be considered for the area.

  Measures R4, R9, and R12, page 64, 68 and 71. These measures do not reference the Puget Sound Clean Air Agency (Section 13.07) requirement for removal of all uncertified stoves by September 30, 2015. This is equivalent to having all solid fuel burning appliances be certified and would be more stringent than the current SIP approved rules in Fairbanks. We believe that these measures need to be evaluated in the BACM and MSM analyses.

  Measure R4 and R9, page 64 and 68. All Wood Stoves Must be Certified. These measure should be evaluated.

- Measure 19-20 and 25, page 36-38 and 39. Renewal and Inspection Requirements. ADEC has not adequately demonstrated their conclusion that Fairbanks has a more stringent measure than Missoula and San Joaquin. We believe that the renewal requirements and inspection/maintenance requirements associated with the Missoula alert permits and San Joaquin registrations allows the local air agency an opportunity to verify on a regular basis that the device operates properly over times. Wood burning appliances require regular maintenance in order to achieve the certified emissions ratings. The FNSB Stage 1 waivers do not have an expiration and do not have an inspection and maintenance component making it less stringent.

- Measure 31, page 43. While the Borough has SIP approved dry wood requirements that prohibit the burning of wet wood and moisture disclosure requirements by sellers, we believe that a measure limiting the sale of wet wood during the winter months should be further analyzed for BACM (and MSM) consideration.

- Measures 33, 35, 36, 37, 43. Multiple Measures identify that recreational fires have been exempted from existing regulations. Small unregulated recreational fires, bonfires, fire pits, and warming fires have the potential to contribute emissions during a curtailment period. The FNSB and ADEC regulations should be re-evaluated for removing this exclusion.

- Measure 49, page 58. Ban on Coal Burning. We believe the regulations in Telluride are more stringent than in Fairbanks. Telluride prohibits coal burning all year whereas in Fairbanks an existing coal stove can burn when there is no curtailment which could contribute additional emissions to the airshed, especially during poor conditions when a curtailment may not have been called. We do not agree with the conclusion that the PM_{10} controls are ineligible for consideration for control of $PM_{2.5}$.

- Measure R20, page 76. Transportation Control Measures related to Vehicle Idling. We have received multiple inquiries regarding community interest in controlling emissions from idling vehicles. These types of control measures should be further evaluated in the BACM and MSM analyses.

- Measure 1, page 79-81. Surcharge on Solid Fuel Burning Appliances. For purposes of implementing an effective program to reduce $PM_{2.5}$ in the Borough we believe that a surcharge may be a helpful way to supplement limited funds. Implementation efforts within the nonattainment area could benefit from $24,000 of additional funding whether used for a code enforcer or other support of the wood smoke programs.

- Additional controls that should be further evaluated for BACM and MSM include:
  - Measure R1, page 63: Natural gas fired kiln or regional kiln.
  - Measure R12, page 71: Replace uncertified stoves in rental units.
  - Measure R17, page 75: Ban use of wood stoves
  - Measure R6, page 65: Remove Hydronic Heaters at Time of Home Sale & Date certain removal of Hydronic heaters. We suggest evaluating these measures at the state and local level.
  - Weatherization / heat retention programs should be evaluated. These should be evaluated for existing homes through energy audits and increasing insulation and energy efficiency. For new construction, building codes (Fairbanks Energy Code) should be evaluated with reference to the IECC Compliance Guide for Homes in Alaska http://insulationinstitute.org/wp-content/uploads/2015/12/AK_2009.pdf, and the DOE R-value recommendations, http://www.fairbanksalaska.us/wp-content/uploads/2011/07/ENERGY-CODE.pdf. (Note: More recent information may be available.)
  - Fuel oil boiler upgrades / operation & maintenance programs should be evaluated.

BACM - Ultra-Low Sulfur Fuel

1. Incomplete Analysis - The report findings provide analysis of the demand curve over a relatively short (12 month) time frame. This analysis appears to be based on a partial equilibrium model. This is a misleading time frame given the volatility of demand side fuel oil pricing. Also, in order to determine the equilibrium price, the analysis must also analyze

the supply curve. The report does not include information about the future supply side costs but needs to in order to make conclusions about the cost to the community of ultra-low sulfur heating oil.

2. Analysis of Increased Supply, Consumption - The report does not address future change in the market nor potential economies of scale to be achieved by an increase in ultra-low sulfur fuel consumption. Page 3 of the report identifies that, "the additional premium to purchase ULS over HS, decreased significantly since 2008-2010. It is likely that, this can be attributed to increased ULS capacity." We believe that the report should further explore the supply side costs.

3. Supply Cost Analysis - A supply side cost analysis is necessary to better understand the cost to the supplier to produce and provide ULS heating fuel. The BACM analysis must start with a transparent and detailed economic analysis of exclusively supplying ultra-low sulfur heating oil to the nonattainment area.

4. BACM Assessment - The current analysis does not provide information needed to assess BACM economic feasibility. The report should analyze the total cost to industry of delivering ultra-low sulfur heating oil to the entire community in terms of standard BACM metrics, $/ton.

BACT

General Comments

At this time, EPA is providing general comments based on review of the draft BACT analyses prepared by ADEC as well as addressing certain issues discussed in earlier BACT comments provided by EPA. Detailed comments regarding each individual analysis are not being provided at this time. While EPA appreciates the time and effort invested by ADEC staff in preparing the draft BACT analyses, the basic cost and technical feasibility information needed to form the basis for retrofit BACT analyses at the specific facilities has not been prepared. In other words, analyses which are adequate to guide decision making regarding control technology decisions for these rather complex retrofit projects cannot be prepared without site specific evaluation of capital control equipment purchase and installation costs, and site specific evaluation of retrofit considerations. EPA will conduct a thorough review of any future BACT or MSM analyses which are prepared based on adequate site specific information, and will provide detailed comments relative to each emission unit and pollutant at that time.

1. Level of Analysis – The analyses are presented as "preliminary BACT/MSM analyses" on the website, but the documents themselves are titled only as BACT analyses and the conclusions only reflect BACT. Additionally, the determinations may not be stringent enough to be considered BACT given that better performing SO_2 control technologies have not been adequately analyzed. These analyses cannot be considered to provide sufficient basis to support a selection of MSM.
2. Site-Specific Quotes Needed – The cost analyses, particularly for SO_2 control technologies, must be based on emission unit-specific quotes for capital equipment purchase and

installation costs at each facility. These are retrofit projects which must be considered individually in order to obtain reliable study/budget level (+/- 30%) cost estimates which are appropriate to use as the basis for decision making in determining BACT and potentially MSM. EPA believes that control decisions of this magnitude justify the relatively small expense of obtaining site-specific quotes.

3. SO_2 Control Technologies – The analyses must include evaluation of circulating dry scrubber (CDS) SO_2 control technology. This demonstrated technology can achieve SO_2 removal rates comparable to wet flue gas desulfurization (FGD) at lower capital and annual costs, and is more amenable to smaller units and retrofits. Modular units are available.
4. Control Equipment Lifetime – The analyses must use reasonable values for control equipment lifetime, according to the EPA control cost manual (EPA CCM). EPA believes that the following equipment lifetimes reflect reasonable assumptions for purposes of the cost analysis for each technology as stated in the EPA control cost manual and other EPA technical support documents. Use of shorter lifetimes for purposes of the cost analysis must include evidence to support the proposed shortened lifetime. One example where EPA agrees a shortened lifetime is appropriate would be where the subject emission unit has a federally enforceable shutdown date. Certain analyses submitted in the past have claimed shortened equipment lifetimes based on the harshness of the climate in Fairbanks. In order to use an equipment life that is shortened based on the harsh climate, evidence must be provided to support the claim. This evidence could include information regarding the actual age of currently operating control equipment, or design documents for associated process equipment such as boilers. Lacking adequate justification, all cost analyses must use the following values for control equipment lifetime:
    a. SCR, Wet FGD, DSI, CDS, SDA – 30 years
    b. SNCR – 20 years
5. Availability of Control Technologies – Technologically feasible control technologies may only be eliminated based on lack of availability if the analysis includes documented information from multiple control equipment vendors (who provide the technology in question) which confirms the technology cannot be available within the appropriate implementation timeline for the emission unit in question.
6. Assumptions and Supporting Documents – All documents cited in the analyses which form the basis for costs used and assumptions made in the analyses must be provided. Assumptions made in the analyses must be reasonable and appropriate for the control technologies included in the cost analysis.
7. Interest Rate – All cost analyses must use the current bank prime interest rate according to the revised EPA CCM. As of May 10, 2018, this rate is 4.75%. See https://www.federalreserve.gov/releases/h15/ (go to bank prime rate in the table).
8. Space Constraints – In order to establish a control technology as not technologically feasible due to space constraints or other retrofit considerations, detailed site specific information must be submitted in order to establish the basis for such a determination, including detailed drawings, site plans and other information to substantiate the claim.
9. Retrofit Factors – All factors that the facility believes complicate the retrofit installation of each technology should be described in detail, and detailed substantiating information must be submitted to allow reasonable determination of an appropriate retrofit factor or whether installation of a specific control technology is technologically infeasible. EPA Region 10

believes that installation factors which would complicate the retrofit installation of the control technology should be evaluated by a qualified control equipment vendor and be reflected in a site-specific capital equipment purchase and installation quote. Lacking site-specific cost information, all factors that the facility believes complicate the retrofit installation of each technology should be described in detail, and detailed substantiating information must be submitted to allow reasonable determination of an appropriate retrofit factor. One example of the many retrofit considerations that must be evaluated is the footprint required for each control technology. A vendor providing a wet scrubber will be able to estimate the physical space required for the technology, and evaluate the existing process equipment configuration and available space at each subject facility. The determination of whether a specific control technology is feasible and what the costs will be may be different at each facility based on this and other factors. Site-specific evaluation of these factors must be conducted in order to provide a reasonable basis for decision making.

10. <u>Control Efficiency</u> – Cost effectiveness calculations for each control technology must be based on a reasonable and demonstrated high end control efficiency achievable by the technology in question at other emission units, or as stated in writing by a control equipment vendor. If a lower pollutant removal efficiency is used as the basis for the analysis, detailed technical justification must be provided. For example, the ability of SCR to achieve over 90% NO_X reduction is well established, yet the ADEC draft analyses assume only 80% control. Use of this lower control efficiency requires robust technical justification.
11. <u>Condensable Particulate Matter</u> – Although the existing control technology on the coal fired boilers may be evaluated as to whether it meets the requirement for BACT for particulate matter, baghouses primarily reduce emissions of filterable particulate matter rather than condensable PM. Given that all condensable PM emitted by the coal fired boilers would be classified as $PM_{2.5}$, the BACT analyses must include consideration of control options for these emissions. Where control technologies evaluated for control of other pollutants may provide a collateral benefit in reducing emissions of $PM_{2.5}$, this should be evaluated as well.
12. <u>Guidance Reference</u> – The steps followed to perform the BACT analysis mentioned in section 2 are from draft NSR/PSD guidance. The correct reference should be 81 FR 58080, 8/24/2016. As a result of this, some of the steps outlined in the BACT analysis need to be updated.
13. <u>Community Burden Estimate</u> – The concepts and approaches document labels capital purchase and installation costs for air pollution control technology at the major source facilities as “community burden” (see Tables 7 and 8, pages 10-11). EPA believes it is important to properly label the cost numbers being used as capital purchase and installation costs, since presenting them as community burden appears to attribute the entire initial capital investment for the various control technologies to the community in a single year, and also ignores annual operation and maintenance costs. As described in the EPA CCM, the cost methodology used by EPA for determining the cost effectiveness of air pollution control technology amortizes the initial capital investment over the expected life of the control device, and includes expected annual operating and maintenance expenses. EPA believes presentation of this annualized cost over the life of the control technology more accurately represents the actual cost incurred and is consistent with how cost effectiveness is estimated in the context of a BACT analysis.
14. <u>Conversion to Natural Gas</u> – For any emission units capable of converting to natural gas combustion (with the requisite changes to the burners, etc), the MSM analysis in particular

should thoroughly evaluate the feasibility of this option. For example, GVEA has stated the combustion turbines at its North Pole Expansion Power Plant have the ability to burn natural gas, and the IGU has indicated the intent to expand the supply of natural gas to Fairbanks and North Pole.

APPENDIX:

Additional Comments and Suggestions

Possible Concepts and Potential Approaches

Throughout all SIP documents references to design values should include a footnote to the source of the information (e.g., "downloaded from AQS on XX/XX/XXX" or "downloaded from [state system] on XX/XX/XXXX") and how exceptional events were treated.

We suggest referencing the August 24, 2016 81 FR 58010 Fine Particulate Matter NAAQS: State Implementation Plan Requirements rule with one consistent term. We suggest the 2016 $PM_{2.5}$ Implementation Rule.

Page 4, Figure 1. The comparative degree days and heating related information is better suited for the sections evaluating BACM and economic feasibility. If intending on using this information to differentiate Fairbanks from other cold climates and/or nonattainment areas, depicting comparative home heating costs would be more supportive.

Page 4, Table 1. The design values in the table and in the discussion need to be updated for 2015-2017.

Page 6-7: The "Totals" row in Table 3 (non-attainment areas emissions by source sector) does not appear to be the sum of the individual source sector emissions.

Page 7: The statement about FNSB experiencing high heating energy demand per square foot needs to be referenced.

Page 7: The discussion of Eielson AFB growth needs a reference to the final EIS.

Page 9: Table 4's title should be changed to "Preliminary Precursor Demonstration Summary"

Page 9: Table 4 includes a column "Modeling Assessment". Not all precursors were assessed with modeling, and modeling is just one tool for the precursor demonstration. A suggestion for the column title is "Result of Precursor Demonstration."

Page 9: Table 5's title should be changed to "Preliminary BACT Summary." Table 5 also needs to update the title to reference "Precursor Demonstration" as the term "Precursor Significance Evaluation" is the incorrect terminology for this analysis.

Page 10: ADEC's proposal to only require one control measure per major stationary source to meet BACT and MSM for SO_2, is not consistent with the Act or rule. As discussed above, BACM and MSM have separate definitions in 40 CFR 51.1000. By extension, the processes for selecting BACM and MSM are laid out separately in the PM2.5 SIP Requirements Rule (compare 40 CFR 51.1010(a) for BACM and 40 CFR 51.1010(b) for MSM).

Page 10: Table 6 should identify the specific dry sorbent injection selected as BACT.

Page 11: Suggest changing “less sources” to “fewer sources.”

Page 13: The statement about an I/M program providing PM benefit needs to be clarified. Is this referring just to NOx and VOC precursor contribution to PM2.5, or also direct PM2.5 benefits?

Page 14: The statement “ADEC interprets the main difference between BACT/BACM and MSM as the time it takes to implement a control” is inaccurate. As discussed above, although the rule sets our different schedules for implementation of MSM and BACM, this is not the only major difference between those concepts. Notably, the rule contemplates a higher stringency for MSM as well as a higher cost/ton threshold for determining economic feasibility of the measure.

Technical Analysis Protocol

Page 2: The design values at the top of the page need to be updated to 2015-2017.

Page 2: Recommend removing the sentence “This site will be included in the Serious SIP’s attainment plan…” as the North Pole Elementary will be involved in the redesignation to attainment in the sense that all past and current monitoring data will be a part of an unmonitored area analysis to show that the entire area has attained the standard in addition to the regulatory monitor locations.

Page 2: Remove the discussion of the nonattainment area split.

Page 2: Paragraph 2, sentence 3 should refer to the unmonitored area analysis.

Page 2: The timeline described at the bottom of the page needs to be modified to reflect a current schedule. No projected year modeling was included in the preliminary draft documents. Control scenario modeling will likely not be completed in Q2 2018.

Page 3: We suggest a sentence overview of the unmonitored area analysis in Section 3.1.

Page 3: Section 3.2 needs to refer to the SPM data and how that will be used in the Serious Plan unmonitored area analysis. This section should discuss current DEC efforts to site a new monitor in Fairbanks.

Page 3: Section 3.4 needs to describe the CMAQ domain in addition to the WRF domain. A figure (map) would help.

Page 4: Section 3.5 needs a more developed discussion of the WRF assessment, including describing the criteria that were used to assess the state-of-the-art, what the current version is, and what version was used.

Page 4: Section 3.6 needs to reference all emission inventories in development, including potential attainment date extension years and RFP years.

Page 4: In Section 4.1, the statement about the Moderate SIP covering the relevant monitors for the Serious SIP is inaccurate. The statement needs to qualify whether it is referring to regulatory monitors or non-regulatory monitors. In addition, the North Pole Fire Station, NCore, and North Pole Elementary monitors were not included in the Moderate SIP.

Page 5: Table 4.1-1's title suggests that all SPM sites are listed, but only sites with regulatory monitors are listed. Please list all the SPM sites used in the unmonitored area analysis in a separate table and modify this title of Table 4.1-1 to reflect that it lists sites that are regulatory.

Page 5: North Pole Elementary was a regulatory site for a part of the baseline period and was NAAQS comparable. Table 4.1-1 needs to be updated.

Page 8: Table 4.2-1 should be updated to include 2011-2017 98th percentiles. Table 4.2-2 should be updated to include 3-year design values for 2013-2017. For clarity, we recommend the 3-year design values include the full period in order to better distinguish from Table 4.2-1. For instance, "2013" would be "2011-2013".

Page 8: The statement starting, "a clear indication…" needs to be amended or removed. It is inaccurate. The prevalence of organic carbon does not indicate the dominance of wood burning, much less a clear indication. Many sources in Fairbanks emit organic carbon.

Page 8: The statement starting "The concentration share…" need to be amended or removed. Suggest removing "drastically". There is no scientific definition of a drastic change in percentages of $PM_{2.5}$ species, nor does the different 56% to 80% appear "drastic."

Page 9: The detailed description of the Simpson and Nattinger analysis does not reflect that SANDWICH process and it is preliminary data. It should be included within the body of the Serious Plan appendix on monitoring, but is out of place in a summary TAP.

Page 9: there are two different tables with the same table number (Table 4.3-1).

Page 10: Please clarify Table 4.4-1. This appears to be the design value calculation for the 5-year baseline design value, 2011-2015. If correct, then please label the 3-year design values according to the three years (e.g., "2011-2013"), clarify the table heading as being the "Five Year Baseline Design Value, 2011-2015 (µg/m3)", and clarify that the last column is the 5 Year Baseline Design Value associated with the table heading.

Page 11: At the end of section 5, please refer to the emission inventory chapter's meteorological discussion of the episodes.

Page 11: Section 6 needs to justify the extent, resolution, and vertical layer structure of the CMAQ domain (and the WRF domain) or refer to where that is included in the Moderate Plan.

Page 13: We suggest changing "PMNAA" to "NAA" to be consistent with the EI chapter.

Page 15, Section 8.1: There needs to be mention of how the F-35 deployment will be considered, with a reference to the final EIS.

Page 15-19: section 8.2-8.6 use the future tense for tasks that have been completed and are inconsistent with the schedule at the beginning of the TAP. Please adjust based on current status.

Page 20, section 9.2 states that "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." This sentence should be revised to reflect that the technological feasibility assessment occurs after identification of all potential control measures for each source and source category.

Page 20, section 9.3 the second sentence should read: "BACM measures found to be economically infeasible for BACM *must* be analyzed for MSM."

Page 21: Section 10.1 needs to be updated to reflect the current CMAQ version (5.2.1) and a discussion of why that model has not been used.

Page 21: Suggest sentence starting "There will be a gap…" be changed to "There is a gap in terms of assessing the performance at the North Pole Fire Station monitor for the Serious Plan because the State Office Building in Fairbanks was the only regulatory monitor at the time of the 2008 base case modeling episodes."

Page 23: Please explain the solid and dashed lines in the soccer plot.

Page 23: Please be sure to include a full discussion of North Pole performance in this section. Even though we lack measurements, we can discuss the ratio of the modeling results at NPFS versus SOB versus that ratio from more recent monitoring data (2011-2015 baseline design value period).

Page 23: Please clarify what is meant by "Moderate Area SIP requirements."

Page 24: The discussion of the 2013 base year discusses representative meteorological conditions without describing what the representative meteorological conditions are for high $PM_{2.5}$. Please reference the discussion of representative meteorological conditions that will be found elsewhere in the SIP.

Page 24: The discussion of the modeling years needs to be consistent and reflect the extension request past 2019. The attainment year cannot be earlier than 2019. Each extension year must be individually requested. For modeling efficiency, we recommend starting with 2024. If that year attains, then 2023 and so on until we have one year that attains and the year before that does not. This should give us the information about what is the earliest year for attainment.

Page 25: We suggest changing "modeling design value" to "design value for modeling"

Page 26: Please clarify the "SMAT" label in the tables. They may be the SANDWICH concentrations and the "5-yr DV" rows are the SMAT concentrations. Please clarify the units in the rows.

Emission Inventory

Clarification – In the EI document we would like to understand the functional difference between the base year, and baseline year

Please identify the methodology for generating ammonia and condensable PM emissions numbers.

Page 1: Please be consistent in “emission inventory” versus “emissions inventory”.

Page 1: “CAA” to “Clean Air Act” for clarity

Page 3: It would be helpful to refer to 172(c)(3) in Section 1.2, bullet 1 as the planning and reporting requirements.

Page 5: Please include extension years and RFP years in Table 1’s calendar years similar to what was done for Table 2. There should be one RFP projected inventory and QM beyond the extended attainment date. It would be helpful to include basic information about extension years and RFP years to better foreshadow Table 2.

Page 7: Please clarify the “winter season” inventory as the “seasonal” inventory that represents the daily average emissions across the baseline episodes.

Page 7, paragraph 1. Please include reference documentation for the following statement, “results in extremely high heating energy demand per square foot experienced in no other location in the lower-48.”

Page 9: Please change “Violations” to “Exceedances.” Exceedance is the term for concentrations over the standard. Violations is the term for dv over the standard.

Page 9: Add “No exceedances were recorded outside the months tabulated in Table 3 that were not otherwise flagged by Alaska DEC as Exceptional Events.”, to the end of the last paragraph on the page.

Page 13: Please clarify the provenance of the BAM data (e.g., “downloaded from [state database or AQS] on XX/XX/XXXX). In particular, it is important to note if the data has been calibrated to the regulatory measurement (aka, corrected BAM).

Page 17-18. Sentence Unclear “For example, a planning inventory based on average daily emissions across the entire six-month nonattainment season will likely reflect a relatively lower fraction of wood use-based space heating emissions than one based on the modeling episode day average since wood use for space heating Fairbanks tends to occur as a secondary heating source on top of a “base” demand typically met by cleaner home heating oil when ambient temperatures get colder.”

Page 19: Remove “Where appropriate,”. All source sectors should be re-inventoried for 2013, even if the emissions for the sector ends up being the same as in 2008.

Page 19: Change “projected forward” to “re-inventoried”, or similar wording. Reserve “project” for when the emission inventory is estimating emissions in a future year.

Page 20: Please refer to EPA’s memo on the use of MOVES2014a for the plug in adjustment. As a reminder, this information is sufficient only for development of the emissions inventory, not for SIP credit.

Page 20: Please submit the technical appendix referenced on page 20. When that is submitted, we expect to provide additional comment. To allow for review, we request expedited submission.

Page 21: At bottom of page, “project” should be “re-inventoried” or something that refers to an inventory produced after the fact.

Page 22, paragraph 1, Space heating area sources. Please further explain how the combined survey data best represents 2013 emissions.

Page 23: Add information about how NH_3 was inventoried for this category.

Page 23, 2nd paragraph from bottom. Facilities need to provide direct PM and all precursors, whether directly submitted or calculated from emissions factors.

Page 23, last paragraph.

- Potential typo – we believe that 2018 should be 2013.
- Question – Does scaling emissions cause any point source to exceed its PTE?

Page 25, bullet 3, Laboratory – Measured Emissions Factors for Fairbanks Heating Devices. The statement “first and most comprehensive systematic” would be more credible if simplified.

Page 27: Clarify how data from the 2014 NEI was modified to reflect emissions in 2013. Were they assumed to be the same between the two years? Or adjusted based on population change, or some other information?

Page 33: Please include information on how the Speciate database was used to develop the modeling inventory (and perhaps elsewhere for the planning inventory, if appropriate).

Precursor Demonstration

Throughout the Serious Area SIP we recommend using the terminology, Precursor Demonstration, to be consistent with the $PM_{2.5}$ Implementation Rule.

General: The overview of the nitrate chemistry is complicated. We suggest you combine the two discussions into one and organize it with the following logic:

1. Describe the two chemical environments: (1) daytime and (2) nighttime.
2. Describe the information that supports that daytime chemistry is not relevant here.
3. Describe the information that supports that nighttime chemistry is limited by excess NO.

4. Describe what happens if the entire emission inventory was increasing by a factor of 3.6 to get appropriate concentrations in the North Pole area. How does ammonium nitrate change?
5. Describe how increasing the emission inventory and then reducing all source sectors by 75% results in less of a reduction in $P_{M2.5}$ than reducing all source sectors by 75% in the original emission inventory.
6. NOTE: We are willing to provide a rough draft of this organization, if provided the original word document.

Title page: remove "com"

Page 2: Recommend using Section 188-190 instead of 7513-7513b.

Page 2: Recommend moving the last three sentences of the first paragraph to the end of the second paragraph.

Page 2: Please add "threshold" after 1.3 in the third paragraph.

Page 2: Please explain concentration-based and sensitivity-based before using the terms.

Page 2: Please add a footnote whether the numbers in the Executive Summary are SANDWICHed or not.

Page 3: Please change "has decided" to "decided."

Page 3: Make sure the concentrations listed for ammonia include ammonium sulfate and ammonium nitrate.

Page 5-7: The figure captions say that concentrations are presented but the images themselves have percentages. Please use concentrations for this analysis.

Page 9: The first paragraph says that the point sources are not responsible for the majority of sulfate at the monitors. Please substantiate that claim, or modify it.

Page 13: Please explain the relevance of referring to the VOC emissions of home heating in this summary of VOCs.

Page 14: Recommend adding "… and adjusted to reflect speciated concentrations for a total PM2.5 equal to the five year 2011-2015 design value" to the sentence that starts "The speciated PM2.5 data [were] analyzed.

Page 14: Please include the results of the concentration based analysis, perhaps as a table.

Page 14: Clarify that the concentration used for NH_3 is the ammonium sulfate and ammonium nitrate. See the draft EPA Precursor Demonstration Guidance.

Page 17: Recommend removing "slightly" and removing the sentence referring to rounding to the nearest tenth of a microgram.

Page 17-18: To help understand what is going on with the bounding run versus the normal run, it would be helpful to have the RRFs for the Modeled 75% scenario.

BACM

Page 9 and throughout: For clarity, please refer to the implementation rule as “$PM_{2.5}$” not “PM”.

Page 14, Table 3. It would be helpful to include filter speciation data.

Page 16, Table 4: Please identify the RACM measures that were technologically and economically feasible but could not be implemented in the RACM timeline or note there were none.

Page 20 and 25, Table 6 and 7: For the final Table identifying the control measures evaluated, it would be helpful to identify the following: measure, cost/ton, BACM determination, MSM determination, and any additional comments.

Page 24: 12 measures were eliminated because they were determined to offer marginal or unquantifiable benefit. However, a measure may offer marginal benefit but may also cost very little. If there is another explanation for why these measures were not considered that follows the BACM steps, please include that in the Serious Area Plan.

Page 28: Stage 1 alerts are referred to multiple times including in Measure 2 on page 28 and Measure 33, pg 47 and pg 48. Please clarify in these analyses whether the measure applies during all stages of alerts and the associated level of control with each stage.

Page 33: Measure 13 identified that no SIPs existed or EPA guidance/requirements for the measure and incorrectly used that rationale as the conclusion for not considering the measure.

Page 34: The discussion of Measure 15 does not clearly state how Alaska and the Borough ensure that devices are taken out at the point of sale. It also does not clearly state the process for ensuring a NOASH application doesn’t involve a stove that should have been taken out at the point of sale. It also states that stoves between 2.5 g/hr and 7.5 g/hr can get a NOASH, whereas page 37 implies that a stove must be <2.5 g/hr to be eligible for a NOASH.

Page 47: Measure 33 in Klamath County and Feather River is more stringent than what exists in Fairbanks now. Fairbanks allows open burning without a permit when there is no stage restriction. Alaska DEC prohibits open burning between November 1 and March 31, but the air quality plan makes it clear that the state relies on the Borough to carry out the air quality program in Fairbanks. The fact that the local borough does not require a permit for open burning outside of curtailments makes this measure less stringent in Fairbanks than in other locations. In addition, Fairbanks does not curtail warming fires during a Stage 1.

Page 48: Measure 34 is less stringent in Fairbanks than in Klamath County. Uncertainty in weather forecasting means that Stage 1 alerts are not called correctly all the time, and not everyone is aware of when an alert is in effect. It is much simpler and less prone to error to prohibit burn barrels and outdoor burning devices entirely.

Page 57: Measure 46 review curtailment exemptions. The current Fairbanks curtailment exemption “These restrictions shall not apply during a power failure.” should be reviewed to clarified that it only applies to homes reliant on electricity for heating. As currently written, it appears overly broad.

Page 68: Measure R7, Ban Use of Hydronic Heaters, incorrectly identifies that no other SIPs implemented the measure as rational for not evaluating.

Page 72: Measure R15 is technologically feasible.

Page 78: It may help to make a section break or Section 2 label for “Analysis of Marginal / Unquantifiable Benefit BACM Measures

Page 81-83: The discussion of Measure 6 may need additional documentation. Anecdotal evidence is that damping is common in Fairbanks and is potentially a bigger source of pollution than not having a damper at very cold conditions. If installation by a certified technician addresses this issue, that should be documented.

Page 84: The quote, “did not know if the rule had worked well” needs a reference. It is also not clear of how relevant that is. It could be implemented well in Fairbanks and the fact that it may not have worked well in another location does not make it technologically infeasible for this location.

Page 85-86: While qualitative assessments are helpful to provide context, a quantitative assessment will be necessary to evaluate the measures as BACM and MSM.

Page 88: There are references to Fairbanks in the conclusion for Measure 17, but the analysis refers to AAC code.

Page 89: There appears to be missing text in the Background section related to Method 9.

Page 91: Measure 23 could consider the solution that the decals could be reflective and would be seen by vehicle headlights. Measure 23 could also consider that the decals are used by neighbors to determine who is or is not in compliance. This may be helpful as citizen compliance assistance efforts could supplement the Borough enforcement program.

Page 98-100: Measure 40 needs to include a discussion of all the areas listed on page 22. In addition, if a date certain measure or if Measure 29 were instituted, Measure 40 would essentially be achieved.

Page 114: Measure R5 describes a similar rule in Utah but lists “none” under implementing jurisdictions. Please make consistent.

ULS Heating Oil

Page vii and Page 16: Please check your information on the percentage of households who have a central oil fired furnace. Please consult ADEC's contractor for the emissions inventory and home heating surveys about (1) the percentage of homes that heat only with an oil furnace, and (2) home with a central oil burner and a wood stove. We have seen different numbers than presented here.

Page 13: Please check the labels for Fairbanks HS #2 and Fairbanks HS #1. They may be switched.

Page 14: The statement that there is "a clear explanation" may not be correct, or at minimum is an overstatement. The difference in price between HS#1 and ULSD has varied over time, and the report did not include an explanation for the variations.

Page 14: The third paragraph assumes that the capital costs of shipping ULS would be more than exists today. However, all heating oil is shipped, regardless of sulfur content, and there is no justification for the report for why shipping ULS would be higher than for HS. Additionally, it is possible that the shipping cost per unit could go down marginally if only one product is being supplied to Fairbanks and/or if the quantity supplied increases.

Page 21: The text and Table 7 present inconsistent information. For instance, the text says that the discounted net-present value of scenario 2 is $10,232 while the table says it is $5,768.56.

ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION
Air Permits Program

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

Prepared by: Aaron Simpson
Supervisor: James R. Plosay
Preliminary Date: May 14, 2019

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Table of Contents

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 within the military installation at Fort Wainwright 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]

This report addresses the significant EUs listed in the DU permit AQ1121TVP02, Revision 2 and the FWA permit AQ0236TVP03, Revision 2. This report provides the Department's review of the BACT analysis for PM-2.5 and BACT analyses provided for oxides of nitrogen (NOx) and sulfur dioxide (SO_2) emissions, which are precursor pollutants that can form PM-2.5 in the atmosphere post combustion.

The 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 NOx, 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.

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

Table A: 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
10	Emergency Generator Engine	762	hp	Building 1060
11	Emergency Generator Engine	762	hp	Building 1060
12	Emergency Generator Engine	82	hp	Building 1193
13	Emergency Generator Engine	587	hp	Building 1555
14	Emergency Generator Engine	320	hp	Building 1563
15	Emergency Generator Engine	1,059	hp	Building 2117
16	Emergency Generator Engine	212	hp	Building 2117
17	Emergency Generator Engine	176	hp	Building 2088
18	Emergency Generator Engine	212	hp	Building 2296
19	Emergency Generator Engine	71	hp	Building 3004
20	Emergency Generator Engine	35	hp	Building 3028
21	Emergency Generator Engine	95	hp	Building 3407
22	Emergency Generator Engine	35	hp	Building 3565
23	Emergency Generator Engine	155	hp	Building 3587
24	Emergency Generator Engine	50	hp	Building 3703
25	Emergency Generator Engine	18	hp	Building 5108
26	Emergency Generator	68	hp	Building 1620
27	Emergency Generator	274	hp	Building 1054
28	Emergency Generator	274	hp	Building 4390
29	Emergency Pump Engine	75	hp	Building 1056
30	Emergency Pump Engine	75	hp	Building 3403
31	Emergency Pump Engine	75	hp	Building 3724
32	Emergency Pump Engine	75	hp	Building 4162
33	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
51a	DC-1 Fly Ash Dust Collector	3,620	acfm	CHPP
51b	DC-2 Bottom Ash Dust Collector	3,620	acfm	CHPP
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 kW	Building 3498
38	Fire Pump #1	120 hp	Building 5009
39	Fire Pump #2	120 hp	Building 5009
40	Waste Oil-Fired Boiler	2.6 MMBtu/hr	Building 5007
???	Distillate Fired Boilers (23)	Varies	Varies
???	Waste Oil-Fired Boiler	2.5 gal/hr	Building 3476
???	Waste Oil-Fired Boiler	2.5 gal/hr	Building 3476

Five-Step BACT Determinations

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

Step 1 Identify All Potentially Available Control Technologies

The Department identifies all available control technologies for the 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 NOx, PM-2.5, and SO_2 emissions from equipment similar to those listed in Table A and Table B.

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 3, 4, and 5, present the Department's BACT determinations for NOx, PM-2.5, and SO_2.

Step 5 Select BACT
The Department selects the most effective control option not eliminated in Step 4 as BACT for the pollutant and EU under review and lists the final BACT requirements determined for each EU in this step. A project may achieve emission reductions through the application of available technologies, changes in process design, and/or operational limitations. The Department reviewed Fort Wainwright's BACT analysis and made BACT determinations for NOx, 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

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

Fort Wainwright has six existing 230 million British Thermal Units (MMBtu)/hr spreader-stoker type boilers that burn coal to produce steam for stationary source-wide heating and power. It also contains small and large emergency engines, fire pumps, and generators, diesel-fired boilers, and material handling equipment subject to BACT. The Department reviewed the control technologies Fort Wainwright identified in their analysis and made a NOx BACT finding for the EUs listed in Tables A and B.

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

3.1 NOx BACT for the Industrial Coal-Fired Boilers

Possible NOx 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 3-1.

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

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

RBLC Review

A review of similar units in the RBLC indicates selective catalytic reduction, selective non-

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

catalytic reduction, low NOx burners, overfire air, and good combustion practices are the principle NOx control technologies installed on industrial coal-fired boilers. The lowest NOx emission rate in the RBLC is 0.05 lb/MMBtu.

Step 1- Identification of NOx Control Technologies for the Industrial Coal-Fired Boilers
From research, the Department identified the following technologies as available for control of NOx emissions from industrial coal-fired boilers:

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

(b) Selective Non-Catalytic Reduction (SNCR)[4]
SNCR involves the non-catalytic decomposition of NOx in the flue gas to N_2 and water using reducing agents such as urea or NH_3. The process utilizes a gas phase homogeneous reaction between NOx and the reducing agent within a specific temperature window. The reducing agent must be injected into the flue gas at a location in the unit that provides the optimum reaction temperature and residence time. The NH_3 process (trade name-Thermal DeNOx) requires a reaction temperature window of 1,600°F to 2,200°F. In the urea process (trade name–NO_xOUT), the optimum temperature ranges between 1,600°F and 2,100°F. Expected NOx removal efficiencies are typically between 40 to 62 percent, according to the RBLC, or between 30 and 50 percent reduction, according to the EPA fact sheet (EPA-452/F-03-031). The Department considers SNCR a technically feasible control technology for the industrial coal-fired boilers.

(c) Non-Selective Catalytic Reduction (NSCR)
NSCR simultaneously reduces NOx and oxidizes CO and hydrocarbons in the exhaust gas to N_2, carbon dioxide (CO_2), and water. The catalyst, usually a noble metal, causes the reducing gases in the exhaust stream (hydrogen, methane, and CO) to reduce both NO and NO_2 to N_2 at a temperature between 800°F and 1,200°F, below the expected temperature of the coal-fired boiler flue gas. NSCR requires a low excess O_2 concentration in the exhaust gas stream to be effective because the O_2 must be depleted

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

before the reduction chemistry can proceed. NSCR is only effective with rich-burn gas-fired units that operate at all times with an air/fuel ratio controller at or close to stoichiometric conditions. Coal-fired boilers operate under conditions far more fuel-lean than required to support NSCR. The Department's research did not identify NSCR as a control technology used to control NOx emissions from large coal-fired boilers installed at any facility after 2005. The Department does not consider NSCR a technically feasible control technology for the industrial coal-fired boilers.

(d) Low NOx Burners (LNBs)
Using LNBs can reduce formation of NOx through careful control of the fuel-air mixture during combustion. Control techniques used in LNBs includes staged air, and staged fuel, as well as other methods that effectively lower the flame temperature. Experience suggests that significant reduction in NOx emissions can be realized using LNBs. The U.S. EPA reports that LNBs have achieved reduction up to 80%, but actual reduction depends on the type of fuel and varies considerably from one installation to another. Typical reductions range from 40% - 60% but under certain conditions, higher reductions are possible. Air staging, or two-stage combustion, is generally described as the introduction of overfire air into the boiler or furnace. Overfire air is the injection of air above the main combustion zone. As indicated by EPA's AP-42, LNBs are applicable to tangential and wall-fired boilers of various sizes but are not applicable to other boiler types such as cyclone furnaces or stokers. The Department does not consider LNBs a technically feasible control technology for the existing stoker type coal-fired boilers.

(e) Circulating Fluidized Bed (CFB)
In a fluidized bed combustor, fuel is introduced to a bed of either sorbent (limestone) or inert material (usually sand) that is fluidized by an upward flow of air. This upward air flow allows for better mixing of the gas and solids to create a better heat transfer and chemical reactions. Combustion takes place in the bed at a lower temperature than other boiler types which lowers the formation of thermally generated NOx. For the purposes of this report, a control technology does not include passive control measures that act to prevent pollutants from forming such as inherent process design features or characteristics. The Department does not consider CFB a technically feasible control technology to retrofit the existing coal-fired boilers.

(f) Low Excess Air (LEA)
Boiler operation with low excess air is considered an integral part of good combustion practices because this process can maximize the boiler efficiency while controlling the formation of NOx. Boilers operated with five to seven percent excess air typically have peak NOx formation from both peak combustion temperatures and chemical reactions. At both lower and higher excess air concentrations the formation of NOx is reduced. At higher levels of excess air, an increase in the formation of CO occurs. CO can increase exponentially at very high levels of excess air and the combustion efficiency is greatly reduced. As a result, the preference is to reduce excess air such that both NOx and CO generation is minimized and the boiler efficiency is optimized. Only one RLBC entry identified low excess air technology as a NOx control alternative for a mass-feed stoker designed boiler. Boilers are regularly designed to operate with low excess air as described

in the previous LNB discussion. The Department considers LEA a technically feasible control technology for the industrial coal-fired boilers.

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

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

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

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

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

(j) Reburn
Reburn is a combustion hardware modification in which the NOx produced in the main combustion zone is reduced in a second combustion zone downstream. This technique involves withholding up to 40 percent (at full load) of the heat input to the main combustion zone and introducing that heat input above the top row of burners to create a reburn zone. Reburn fuel (natural gas, oil, or pulverized coal) is injected with either air or flue gas to create a fuel-rich zone that reduces the NOx created in the main combustion zone to nitrogen and water vapor. The fuel-rich combustion gases from the reburn zone are completely combusted by injecting overfire air above the reburn zone. Reburn may be applicable to many boiler types firing coal as the primary fuel, including tangential, wall-fired, and cyclone boilers. However, the application and effectiveness are site-specific because each boiler is originally designed to achieve specific steam conditions and

capacity which may be altered due to reburn. Commercial experience is limited; however, this limited experience does indicate NOx reduction of 50 to 60 percent from uncontrolled levels may be achieved. Reburn combustion control would require significant changes to the design of the existing boilers. Therefore, the Department does not consider reburn to be a technically feasible control technology to retrofit the existing industrial coal-fired boilers.

Step 2 - Eliminate Technically Infeasible NOx Control Technologies for the Coal-Fired Boilers

As explained in Step 1 of Section 3.1, the Department does not consider non-selective catalytic reduction, low NOx burners, circulating fluidized beds, fuel switching, steam/water injection, or reburn as technically feasible technologies to control NO_x emissions from existing industrial coal-fired boilers.

Step 3 - Rank the Remaining NOx Control Technologies for Industrial Coal-Fired Boilers

The following control technologies have been identified and ranked by efficiency for the control of NOx emissions from the coal-fired industrial boilers:

(a) Selective Catalytic Reduction (70% - 90% Control)
(b) Selective Non-Catalytic Reduction (30% - 50% Control)
(g) Good Combustion Practices (Less than 40% Control)
(f) Low Excess Air (10% - 20% Control)

Step 4 - Evaluate the Most Effective Controls

Fort Wainwright BACT Proposal

Fort Wainwright provided an economic analysis for the installation of selective catalytic reduction and selective non-catalytic reduction. A summary of the analysis is shown below:

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

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annual Costs ($/year)	Cost Effectiveness ($/ton)
SCR	177	88	$13,860,931	$2,222,777	$25,166
SNCR	105	52	$5,598,476	$936,162	$17,852
Capital Recovery Factor = 0.1424 (7% interest rate for a 10 year equipment life)					

Fort Wainwright contends that the economic analysis indicates the level of NOx reduction does not justify the use of selective catalytic reduction or selective non-catalytic reduction for the coal-fired boilers based on the excessive cost per ton of NOx removed per year.

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

(a) NOx emissions from the operation of the coal-fired boilers will be controlled with good combustion practices and injection of overfire air with oxygen trim systems.

(b) NOx emissions from the coal-fired boilers will not exceed 0.46 lb/MMBtu over a 3-hour averaging period.

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

Department Evaluation of BACT for NOx Emissions from the Industrial Coal-Fired Boilers
The Department revised the cost analyses provided by Fort Wainwright for the installation of SCR and SNCR using the cost estimating procedures identified in EPA's May 2016 Air Pollution Control Cost Estimation Spreadsheet for Selective Catalytic Reduction,[5] and Selective Non-Catalytic Reduction,[6] using the unrestricted potential to emit from the six coal-fired boilers combined, a baseline emission rate of 0.58 lb NOx/MMBtu,[7] a retrofit factor of 1.5 for a difficult retrofit, a NOx removal efficiency of 90% and 50% for SCR and SNCR respectively, an interest rate of 5.5% (current bank prime interest rate), and a 20 year equipment life. A summary of the analysis is shown below:

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

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR	1,447	1,302	$59,328,700	$6,816,393	$5,234
SNCR	1,447	723	$9,247,363	$1,628,874	$2,251
Capital Recovery Factor = 0.0837 (5.5% interest rate for a 20 year equipment life)					

The Department's economic analysis indicates the level of NOx reduction justifies the use of selective catalytic reduction or selective non-catalytic reduction as BACT for the coal-fired boilers located in the Serious PM-2.5 nonattainment area.

Step 5 - Selection of NOx BACT for the Industrial Coal-Fired Boilers
The Department's finding is that selective catalytic reduction and selective non-catalytic reduction are both economically and technically feasible control technologies for NOx. Since selective catalytic reduction has a higher control efficiency, it is selected as BACT to control NOx emissions from the industrial coal-fired boilers.

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

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

(b) NOx emissions from DU EUs 1 through 6 shall not exceed 0.060 lb/MMBtu averaged over a 3-hour period; and

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

[5] https://www3.epa.gov/ttn/ecas/docs/scr_cost_manual_spreadsheet_2016_vf.xlsm
[6] https://www3.epa.gov/ttn/ecas/docs/sncr_cost_manual_spreadsheet_2016_vf.xlsm
[7] Emission factor from AP-42 Table 1.1-3 for spreader stoker sub-bituminous coal (8.8 lb NOx/ton) and converted to lb/MMBtu using heat value for Usibelli Coal of 7,560 Btu/lb, http://www.usibelli.com/coal/data-sheet.

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

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

Facility	Process Description	Capacity	Limitation	Control Method
Fort Wainwright	6 Coal-Fired Boilers	1,380 MMBtu/hr	0.06 lb/MMBtu[8]	Selective Catalytic Reduction
UAF	Dual Fuel-Fired Boiler	295.6 MMBtu/hr	0.02 lb/MMBtu[9]	Selective Catalytic Reduction
Chena	4 Coal-Fired Boilers	497 MMBtu/hr	0.05 lb/MMBtu[10]	Selective Catalytic Reduction

3.2 NOx BACT for the Diesel-Fired Boilers

Possible NOx 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 3-5.

Table 3-5. RBLC Summary of NOx Control for Diesel-Fired Boilers

Control Technology	Number of Determinations	Emission Limits (g/hp-hr)
Low-NOx Burner	8	0.023 - 0.14
Good Combustion Practices	1	0.01
No Control Specified	2	0.070 - 0.12

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

Step 1 - Identification of NOx Control Technologies for the Diesel-Fired Boilers
From research, the Department identified the following technologies as available for control of NOx emissions from diesel-fired boilers:

(a) Low NOx Burners (LNBs)
The theory of LNBs was discussed in detail in the NOx BACT for the coal-fired boilers and will not be repeated here. The Department considers LNB 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.

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[8] Calculated using a 90% NOx control efficiency for SCR with uncontrolled emission factor from AP-42 Table 1.1-3 for spreader stoker sub-bituminous coal (8.8 lb NOx/ton) and converted to lb/MMBtu using heat value for Usibelli Coal of 7,560 Btu/lb, http://www.usibelli.com/coal/data-sheet.
[9] Calculated using a 90% NOx control efficiency for SCR with uncontrolled emission rate from 40 C.F.R. 60.44b(l)(1) [NSPS Subpart Db].
[10] Calculated using a 90% NOx control efficiency for SCR with uncontrolled emission rate from most recent NOx source test, which occurred on Oct 27, 2018.

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

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

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

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

(b)	Limited Operation	(94% Control)
(a)	Low NOx Burners	(35% - 55% 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 NOx 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) Limiting operation of the other 24 diesel-fired boilers to testing, maintenance, and emergency use with the exception of the waste fuel boilers.

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

The Department reviewed Fort Wainwright’s proposal and finds that the 27 diesel-fired boilers have a combined potential to emit (PTE) of less than three tons per year (tpy) for NOx based on non-emergency operation of 500 hours per year. At three tpy, the cost effectiveness in terms of dollars per ton for add-on pollution control for these units is economically infeasible.

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

(a) NOx emissions from the diesel-fired boilers shall not exceed 0.15 lb/MMBtu[11];
(b) Combined operating limit of 600 hours per year for FWA EUs 8, 9, and 10;
(c) Limit non-emergency operation of the 27 diesel fired boilers, with the exception of the waste-fuel boilers, to no more than 500 hours per year, for maintenance checks and readiness testing; and
(d) Maintain good combustion practices by following the manufacturer's maintenance procedures at all times of operation.

Table 3-6 lists the proposed NOx BACT determination for this facility along with those for other diesel-fired boilers rated at less than 100 MMBtu/hr in the Serious PM-2.5 nonattainment area.

Table 3-6. Comparison of NOx BACT for the Diesel-Fired Boilers at Nearby Power Plants

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

3.3 NOx BACT for the Large Diesel-Fired Engines, Fire Pumps, and Generators

Possible NOx emission control technologies for large engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 17.100 to 17.190, Large Internal Combustion Engines (>500 hp). The search results for large diesel-fired engines are summarized in Table 3-7.

Table 3-7. RBLC Summary of NOx Control for Large Diesel-Fired Engines

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

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

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

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

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

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

(c) Fuel Injection Timing Retard (FITR)
FITR reduces NOx emissions by the delay of the fuel injection in the engine from the time the compression chamber is at minimum volume to a time the compression chamber is expanding. Timing adjustments are relatively straightforward. The larger volume in the compression chamber produces a lower peak flame temperature. With the use of FITR the engine becomes less fuel efficient, particulate matter emissions increase, and there is a limit with respect to the degree the timing may be retarded because an excessive timing delay can cause the engine to misfire. The timing retard is generally limited to no more than three degrees. Diesel engines may also produce more black smoke due to a decrease in exhaust temperature and incomplete combustion. FITR can achieve up to 50 percent NOx reduction. Due to the increase in particulate matter emissions resulting from FITR, this technology will not be carried forward.

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

(e) Federal Emission Standards
RBLC NOx determinations for federal emission standards require the engines meet the requirements of 40 C.F.R. 60 Subpart IIII, 40 C.F.R 63 Subpart ZZZZ, non-road engines (NREs), or EPA tier certifications. Subpart IIII applies to stationary compression ignition internal combustion engines that are manufactured or reconstructed after July 11, 2005.

The Department considers meeting the technology based New Source Performance Standards (NSPS) of Subpart IIII as a technically feasible control technology for the large diesel-fired engines.

(f) 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 Prevention of Significant Deterioration (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.

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

Step 2 - Eliminate Technically Infeasible NOx Control Technologies for the Large Engines
As explained in Step 1 of Section 3.3, the Department does not consider fuel injection timing retard and ignition timing retard as technically feasible technologies to control NOx emissions from the large diesel-fired engines.

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

(f)	Limited Operation	(94% Control)
(a)	Selective Catalytic Reduction	(90% Control)
(g)	Good Combustion Practices	(Less than 40% Control)
(b)	Turbocharger and Aftercooler	(6% – 12% Control)
(e)	Federal Emission Standards	(Baseline)

Step 4 - Evaluate the Most Effective Controls

Fort Wainwright BACT Proposal

Fort Wainwright proposes the following as BACT for NOx 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) 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.

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

The Department reviewed Fort Wainwright's proposal and finds that NOx emissions from the large diesel-fired engines can additionally 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 NOx BACT for the Large Diesel-Fired Engines
The Department's finding is that the BACT for NOx 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 EU 8 to 500 hours per year;

(c) Limit non-emergency operation of DU EUs 8, 10, 11, 13, and 15 to no more than 100 hours per year each for maintenance checks and readiness testing;

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

(e) Comply with the numerical BACT emission limits listed in Table 3-8 for NOx.

Table 3-8 Proposed NOx BACT Limits for the Large Diesel-Fired Engines

Location	EU	Year	Description	Size	Status	BACT Limit	Proposed BACT
DU	8	2009	Generator Engine	2,937 hp	Certified Engine	4.8 g/hp-hr	Limited Operation for Non-Emergency Use (100 hours per year each) Good Combustion Practices
DU	10	2010	Generator Engine	762 hp	Certified Engine	4.8 g/hp-hr	
DU	11	2010	Generator Engine	762 hp	Certified Engine	4.8 g/hp-hr	
DU	13	2008	Generator Engine	587 hp	Certified Engine	3.0 g/hp-hr	
DU	15	2005	Generator Engine	1,059 hp	Manufacturer Information	5.75 g/hp-hr	
FWA	11	2003	Caterpillar 3512	1,206 hp	AP-42 Table 3.4-1	10.9 lb/hp-hr	Limit combined operation to 600 hours per year
FWA	12	2003	Caterpillar 3512	1,206 hp	AP-42 Table 3.4-1	10.9 lb/hp-hr	
FWA	13	2003	Caterpillar 3512	1,206 hp	AP-42 Table 3.4-1	10.9 lb/hp-hr	

Table 3-9 lists the proposed NOx 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 3-9. Comparison of NOx BACT for Large Diesel-Fired Engines at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
Fort Wainwright	8 Large Diesel-Fired Engines	> 500 hp	3.0 – 10.9 g/hp-hr	Limited Operation Good Combustion Practices Federal Emission Standards
UAF	Large Diesel-Fired Engine	13,266 hp	1.3 g/hp-hr	Selective Catalytic Reduction Turbocharger and Aftercooler Good Combustion Practices Limited Operation
GVEA North Pole	Large Diesel-Fired Engine	600 hp	10.9 g/hp-hr	Turbocharger and Aftercooler Good Combustion Practices Limited Operation
GVEA Zehnder	2 Large Diesel-Fired Engines	11,000 hp (each)	3.7 g/hp-hr	Turbocharger and Aftercooler Good Combustion Practices Limited Operation

3.4 NOx BACT for the Small Emergency Engines, Fire Pumps, and Generators

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

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

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

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

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

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

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

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

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

(e) Limited Operation
Limiting the operation of emission units reduces the potential to emit for those units. The Department considers limited operation as a technically feasible control technology for the small diesel-fired engines.

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

Step 2 - Eliminate Technically Infeasible NOx Control Technologies for the Small Engines
As explained in Step 1 of Section 3.4, the Department does not consider ignition timing retard as a technically feasible technology to control NOx emissions from the small diesel-fired engines.

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

(e)	Limited Operation	(94% Control)
(a)	Selective Catalytic Reduction	(90% Control)
(b)	Turbocharger and Aftercooler	(6% – 12% Control)
(f)	Good Combustion Practices	(Less than 40% 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 NOx emissions from the small diesel-fired engines:

(a) Good Combustion Practices; and

(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.

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

The Department reviewed Fort Wainwright’s proposal and found that in addition to maintaining good combustion practices and complying with federal emission standards, limiting operation of the small diesel-fired engines during non-emergency operation to no more than 100 hours per year each is BACT for NOx emissions.

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

(a) Limit non-emergency operation of DU EUs 9, 12, 14, 16 through 28, 29a, 30, 31a, 32, 33, 34, 35, 36, and FWA EUs 26 through 39 to no more than 100 hours per year each for maintenance checks and readiness testing;

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

(c) Comply with the numerical BACT emission limits listed in Table 3-11 for NOx.

Table 3-11. Proposed NOx BACT Limits for the 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	0.031 lb/hp-hr	Limited Operation for Non-Emergency Use (100 hours per year each) Good Combustion Practices
DU	12	2002	Generator Engine	82 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
DU	14	2008	Generator Engine	320 hp	Certified Engine	4.0 g/kW-hr	
DU	16	2005	Generator Engine	212 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
DU	17	2007	Generator Engine	176 hp	Permit condition 23.1c	6.9 g/hp-hr	
DU	18	2005	Generator Engine	212 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
DU	19	2007	Generator Engine	71 hp	Certified Engine	7.5 g/kW-hr	
DU	20	1976	Generator Engine	35 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
DU	21	2001	Generator Engine	95 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
DU	22	1989	Generator Engine	35 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
DU	23	2003	Generator Engine	155 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
DU	24	1993	Generator Engine	50 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
DU	25	2011	Generator Engine	18 hp	Certified Engine	7.5 g/kW-hr	
DU	26	2003	Generator Engine	68 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
DU	27	2010	Generator Engine	274 hp	Certified Engine	4.0 g/kW-hr	
DU	28	2010	Generator Engine	274 hp	Certified Engine	4.0 g/kW-hr	
DU	30	1952	Lift Pump Engine	75 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
DU	32	1955	Lift Pump Engine	75 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
DU	33	1994	Lift Pump Engine	75 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
DU	34	1995	Well Pump Engine	220 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
DU	35	2009	Well Pump Engine	55 hp	Certified Engine	4.7 g/kW-hr	
DU	36	1995	Well Pump Engine	220 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
DU	29a	2014	Lift Pump Engine	74 hp	Certified Engine	4.7 g/kW-hr	
DU	31a	2014	Lift Pump Engine	74 hp	Certified Engine	4.7 g/kW-hr	
FWA	26	2012	QSB7-G3 NR3	295 hp	Certified Engine	4.0 g/kW-hr	
FWA	27	2009	4024HF285B	67 hp	Certified Engine	4.7 g/kW-hr	
FWA	28	2007	CAT C9 GENSET	398 hp	Certified Engine	4.0 g/kW-hr	
FWA	29	ND	TM30UCM	47 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
FWA	30	2007	JW64-UF30	275 hp	Certified Engine	4.0 g/kW-hr	
FWA	31	1994	DDFP-04AT	235 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
FWA	32	1994	DDFP-04AT	235 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
FWA	33	1994	DDFP-04AT	235 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
FWA	34	1994	DDFP-04AT	235 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
FWA	35	1977	N-855-F	240 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
FWA	36	1977	N-855-F	240 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
FWA	37	2005	JU4H-UF40	94 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
FWA	38	1996	PDFP-06YT	120 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
FWA	39	1996	PDFP-06YT	120 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	

Table 3-12 lists the proposed NOx BACT determination for this facility along with those for other diesel-fired engines rated at less than 500 hp located in the Serious PM-2.5 nonattainment area.

Table 3-12. Comparison of NOx BACT for Small Diesel Engines at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
Fort Wainwright	41 Small Diesel-Fired Engines	< 500 hp	0.007 – 0.031 lb/hp-hr	Limited Operation for Non-Emergency Use (100 hours per year each) Good Combustion Practices
UAF	Six Small Diesel-Fired Engines	< 500 hp	0.0007 – 0.031 lb/hp-hr	Turbocharger and Aftercooler Good Combustion Practices Limited Operation

4. BACT DETERMINATION FOR PM-2.5

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

4.1 PM-2.5 BACT for the 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.

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,[12] pulse-jet,[13] and reverse-air.[14] Fabric filter systems have control efficiencies of 95% to 99.9%, and are generally specified to meet a discharge concentration of filterable particulate (e.g., 0.01 grains per dry standard cubic feet). The Department considers fabric filters a technically feasible control technology for the 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%.[15] 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%.[16] The 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%.[17] One advantage of wet scrubbers is that they can be effective on condensable particulate matter. A disadvantage of wet scrubbers is that they consume water and produce water and sludge. For fine particulate control, a venturi scrubber can be used, but typical loadings for such a scrubber are 0.1-50 grains/scf. The Department considers the use of wet scrubbers 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

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

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
The theory of GCPs was discussed in detail in the NOx BACT 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 industrial 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 to obtain an emission rate.

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) at all times the units are in operation;

(b) PM-2.5 emissions from DU EUs 1 through 6 shall not exceed 0.006 lb/MMBtu[18] averaged over a 3-hour period; and

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

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

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

Facility	Process Description	Capacity	Limitation	Control Method
Fort Wainwright	6 Coal-Fired Boilers	1380 MMBtu/hr	0.006 lb/MMBtu[18]	Full stream baghouse
UAF	Dual Fuel-Fired Boiler	295.6 MMBtu/hr	0.006 lb/MMBtu[18]	Fabric Filters

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

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

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

Step 1 - Identification of PM-2.5 Control Technology for the 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 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 NOx BACT 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 27 diesel-fired boilers have a combined PTE of less than one tpy for PM-2.5 based on non-emergency operation of 500 hours per year. At one tpy, the cost effectiveness in terms of dollars per ton for add-on pollution control for these units is economically infeasible.

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

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

(a) PM-2.5 emissions from the diesel-fired boilers shall not exceed 0.012 lb/MMBtu[19] averaged over a 3-hour period, with the exception of the waste fuel boilers which must comply with the State particulate matter emissions standard of 0.05 grains per dry standard cubic foot under 18 AAC 50.055(b)(1);

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

(c) Limit non-emergency operation of the 27 diesel fired boilers, with the exception of the waste-fuel boilers, to no more than 500 hours per year, for maintenance checks and readiness testing; and

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

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	27 Diesel-Fired Boilers	< 100 MMBtu/hr	0.012 lb/MMBtu[19]	Good Combustion Practices
UAF	3 Diesel-Fired Boilers	< 100 MMBtu/hr	0.012 lb/MMBtu[19]	Limited Operation Good Combustion Practices
Zehnder	2 Diesel-Fired Boilers	< 100 MMBtu/hr	0.012 lb/MMBtu[19]	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

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

PM-2.5 control technologies installed on large diesel-fired engines. The lowest PM-2.5 emission rate in the RBLC is 0.02 g/hp-hr.

Step 1 - Identification of PM-2.5 Control Technology for the Large Diesel-Fired 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 NOx BACT 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 EU 8 to 500 hours of operation per year;

(c) Limit non-emergency operation of DU EUs 8, 10, 11, 13, and 15 to no more than 100 hours each per year for maintenance checks and readiness testing;

(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
DU	10	2010	Generator Engine	762 hp	Certified Engine	0.15 g/hp-hr	40 CFR 60 Subpart IIII
DU	11	2010	Generator Engine	762 hp	Certified Engine	0.15 g/hp-hr	40 CFR 60 Subpart IIII
DU	13	2008	Generator Engine	587 hp	Certified Engine	0.15 g/hp-hr	40 CFR 60 Subpart IIII
DU	15	2005	Generator Engine	1,059 hp	AP-42 Table 3.4-1	0.32 g/hp-hr	Good Combustion Practices
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	

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 Engine	13,266 hp	0.32 g/hp-hr	Positive Crankcase Ventilation 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 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 for the large diesel-fired engines and will not be repeated here. The Department considers DOC a technically feasible control technology for the small diesel-fired engines.

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

(d) Federal Emission Standards

The theory behind federal emission standards was discussed in detail in the PM-2.5 BACT for the large diesel-fired engines and will not be repeated here. The Department considers 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 NOx BACT 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) Good Combustion Practices;

(b) 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

(c) 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, 12, 14, 16 through 28, 29a, 30, 31a, 32, 33, 34, 35, 36, and FWA EUs 26 through 39 to no more than 100 hours per year each for maintenance checks and readiness testing;

(c) Maintain good combustion practices by following the manufacturer's 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	12	2002	Generator Engine	82 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
DU	14	2008	Generator Engine	320 hp	Certified Engine	0.2 g/kW-hr	
DU	16	2005	Generator Engine	212 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
DU	17	2007	Generator Engine	176 hp	Permit condition 23.1c	0.40 g/hp-hr	
DU	18	2005	Generator Engine	212 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
DU	19	2007	Generator Engine	71 hp	Certified Engine	0.4 g/kW-hr	
DU	20	1976	Generator Engine	35 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
DU	21	2001	Generator Engine	95 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-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	24	1993	Generator Engine	50 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
DU	25	2011	Generator Engine	18 hp	Certified Engine	0.4 g/kW-hr	
DU	26	2003	Generator Engine	68 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
DU	27	2010	Generator Engine	274 hp	Certified Engine	0.2 g/kW-hr	
DU	28	2010	Generator Engine	274 hp	Certified Engine	0.2 g/kW-hr	
DU	30	1952	Lift Pump Engine	75 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
DU	32	1955	Lift Pump Engine	75 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
DU	33	1994	Lift Pump Engine	75 hp	AP-42, Table 3.3-1	2.20 E-3 lb/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	29a	2014	Lift Pump Engine	74 hp	Certified Engine	0.03 g/kW-hr	
DU	31a	2014	Lift Pump Engine	74 hp	Certified Engine	0.03 g/kW-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	

Location	EU	Year	Description	Size	Status	BACT Limit	Proposed BACT
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	

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	41 Small Diesel-Fired Engines	< 500 hp	0.015 – 1.0 g/hp-hr	Good Combustion Practices Limited Operation
UAF	One Small Diesel-Fired Engine	< 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 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 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 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 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 EUs 7a – 7c, 51a, and 51b shall be controlled by operating and maintaining fabric filters 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) Initial compliance with the PM-2.5 emission rates for the material handling units, except EU 52, shall be demonstrated with a performance test to obtain an emission rate.

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	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[20]	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.

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

[20] 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.

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
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.

(e) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT 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.

Step 2 - Eliminate Technically Infeasible SO_2 Control Technologies for Coal-Fired Boilers
All identified control devices are technically feasible for the industrial coal-fired boilers.

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)
(b)	Spray Dry Absorbers	(90% Control)
(c)	Dry Sorbent Injection (Duct Sorbent Injection)	(50 – 80% Control)
(d)	Low Sulfur Coal	(30% Control)
(e)	Good Combustion Practices	(Less than 40% Control)

Step 4 - Evaluate the Most Effective Controls

Fort Wainwright BACT Proposal

Fort Wainwright provided an economic analysis of the installation of wet and dry scrubber 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)
Wet Scrubber	1,767	1,749	???	???	6,900 - 13,800

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annual Costs ($/year)	Cost Effectiveness ($/ton)
Spray-Dry Scrubber	1,767	1,590	???	???	5,200 - 6,200
Dry Sorbent Injection[21]	1,767	1,414	6,191,696	6,384,196	4,516 - 5,968
Capital Recovery Factor = 0.1424 (7% interest rate for a 10 year equipment life)					

Fort Wainwright contends that the economic analysis indicates the level of SO_2 reduction does not justify the use of wet scrubbers, semi-dry scrubbers, or dry scrubber systems (dry-sorbent injection) for the coal-fired boilers based on the excessive cost per ton of SO_2 removed per year.

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 300,000 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 revised the cost analysis provided for the installation of wet scrubbers, semi-dry scrubbers (spray dry absorbers), and dry scrubbers (dry sorbent injection) using a potential to emit of 1,168 tpy for the six coal-fired boilers combined (calculated using the existing permit limit of 336,000 tons of coal per year combined), a baseline emission rate of 0.46 lb SO_2/MMBtu,[22] a retrofit factor of 1.5 for difficult retrofits, a SO_2 removal efficiency of 99%, 90% and 80% for wet scrubbers, spray dry absorbers and dry sorbent injection respectively, an interest rate of 5.5% (current bank prime interest rate), and a 15 year equipment life. A summary of the analysis is shown below:

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

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annual Costs ($/year)	Cost Effectiveness ($/ton)
Wet Scrubber	1,168	1,157	138,118,131	23,913,899	20,673
Spray Dry Absorbers	1,168	1,052	125,929,192	22,305,559	21,211

[21] Calculated using Amerair Industries Proposal for 80% removal of SO_2 emissions.
[22] Calculated assuming a 0.2% sulfur content by weight (typical gross as received) and a higher heating value of 7,560 Btu/lb for Healy coal (average of gross as received range) http://www.usibelli.com/coal/data-sheet, and AP-42 Table 1.1-3 emission factors for spreader stoker boilers combusting sub-bituminous coal.

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annual Costs ($/year)	Cost Effectiveness ($/ton)
Dry Sorbent Injection	1,168	935	15,279,601	9,655,624	10,329
Capital Recovery Factor = 0.0996 (5.5% interest rate for a 15 year equipment life)					

The Department's economic analysis indicates the level of SO_2 reduction justifies the use of dry sorbent injection as BACT for the 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 0.10 lb/MMBtu[23] 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.

(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
Fort Wainwright	6 Coal-Fired Boilers	1380 MMBtu/hr (combined)	0.10 lb/MMBtu[23]	Dry Sorbent Injection Limited Operation Low Sulfur Coal
UAF	Dual Fuel-Fired Boiler	295.6 MMBtu/hr	0.10 lb/MMBtu	Dry Sorbent Injection Limestone Injection Low Sulfur Coal
Chena	4 Coal-Fired Boilers	497 MMBtu/hr (combined)	0.10 lb/MMBtu	Dry Sorbent Injection Low Sulfur Coal

[23] BACT limit selected after evaluating existing emission limits in the RBLC database for coal-fired boilers, taking into account previous source test data from coal-fired boilers in Alaska and actual emissions data from other sources employing similar types of controls, using site specific vendor quotes provided by Amerair Industries, and in-line with EPA's pollution control Fact Sheets while keeping in mind that BACT limits must be achievable at all times.

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 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 NOx BACT 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 27 diesel fired boilers have a combined PTE of less than ten tpy for SO_2 based on non-emergency operation of 500 hours per year. At ten tpy, the cost effectiveness in terms of dollars per ton for add-on pollution control for these units is economically infeasible.

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

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

(a) SO_2 emissions from the diesel-fired boilers shall be controlled by only combusting ULSD, with the exception of the waste fuel boilers;

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

(c) Limit non-emergency operation of the 27 diesel fired boilers, with the exception of the waste-fuel boilers, to no more than 500 hours per year, for maintenance checks and readiness testing; and

(d) 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	Diesel-Fired Boilers	< 100 MMBtu/hr	15 ppmw S in fuel	Limited Operation Good Combustion Practices Ultra-Low Sulfur Diesel
	Waste Fuel-Fired Boilers		0.5 % S by weight	Good Combustion Practices
UAF	3 Diesel-Fired Boilers	< 100 MMBtu/hr	15 ppmw S in fuel	Good Combustion Practices Ultra-Low Sulfur Diesel

Facility	Process Description	Capacity	Limitation	Control Method
GVEA Zehnder	2 Diesel-Fired Boilers	< 100 MMBtu/hr	15 ppmw S in fuel	Good Combustion Practices Ultra-Low Sulfur Diesel

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 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
The theory of federal emission standards was discussed in detail in the NOx BACT for the large diesel-fired engines and will not be repeated here. 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 NOx BACT 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 EUs 8, 10, 11, 13, and 15 and FWA EUs 11, 12, and 13 shall be controlled by only combusting ULSD;

(b) Limit 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 DU EUs 8, 10, 11, 13, and 15 to no more than 100 hours per year, for maintenance checks and readiness testing; 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 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 NOx BACT 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, 12, 14, 16 through 28, 29a, 30, 31a, 32, 33, 34, 35, 36, and FWA EUs 26 through 39 to no more than 100 hours per year each for maintenance checks and readiness testing;

(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 5-10. Comparison of SO_2 BACT for Small Diesel-Fired Engines at Nearby Power Plants

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

6. BACT DETERMINATION SUMMARY

Table 6-1. Proposed NOx BACT Limits

EU ID	Description	Capacity	Proposed BACT Limit	Proposed BACT Control
DU 1	Six Coal Fired Boiler 3	230 MMBtu/hr	0.06 lb/MMBtu	Selective Catalytic Reduction
DU 2	Six Coal Fired Boiler 4	230 MMBtu/hr	0.06 lb/MMBtu	
DU 3	Six Coal Fired Boiler 5	230 MMBtu/hr	0.06 lb/MMBtu	
DU 4	Six Coal Fired Boiler 6	230 MMBtu/hr	0.06 lb/MMBtu	
DU 5	Six Coal Fired Boiler 7	230 MMBtu/hr	0.06 lb/MMBtu	
DU 6	Six Coal Fired Boiler 8	230 MMBtu/hr	0.06 lb/MMBtu	
FWA 8	Backup Diesel-Fired Boiler 1	19 MMBtu/hr	0.15 lb/MMBtu	Good Combustion Practices Limited Operation (600 hours/year combined)
FWA 9	Backup Diesel-Fired Boiler 2	19 MMBtu/hr	0.15 lb/ MMBtu	
FWA 10	Backup Diesel-Fired Boiler 3	19 MMBtu/hr	0.15 lb/ MMBtu	
N/A	Diesel-Fired Boilers (24)	Varies	0.15 lb/ MMBtu	Good Combustion Practices Limited Operation (500 hours/year each, for non-emergency operation)
DU 8	Generator Engine	2,937 hp	4.8 g/hp-hr	Good Combustion Practices Limited Operation (100 hours/year each, for non-emergency operation)
DU 10	Generator Engine	762 hp	4.8 g/hp-hr	
DU 11	Generator Engine	762 hp	4.8 g/hp-hr	
DU 13	Generator Engine	587 hp	3.0 g/hp-hr	
DU 15	Generator Engine	1,059 hp	5.75 g/hp-hr	
FWA 11	Caterpillar 3512	1,206 hp	10.9 g/hp-hr	Good Combustion Practices Limited Operation (600 hours/year combined)
FWA 12	Caterpillar 3512	1,206 hp	10.9 g/hp-hr	
FWA 13	Caterpillar 3512	1,206 hp	10.9 g/hp-hr	
DU 9	Generator Engine	353 hp	0.031 lb/hp-hr	Good Combustion Practices Limited Operation (100 hours/year each, for non-emergency operation)
DU 12	Generator Engine	82 hp	0.031 lb/hp-hr	
DU 14	Generator Engine	320 hp	4.0 g/kW-hr	
DU 16	Generator Engine	212 hp	0.031 lb/hp-hr	
DU 17	Generator Engine	176 hp	6.9 lb/hp-hr	
DU 18	Generator Engine	212 hp	0.031 lb/hp-hr	
DU 19	Generator Engine	71 hp	7.5 g/kW-hr	
DU 20	Generator Engine	35 hp	0.031 lb/hp-hr	

EU ID	Description	Capacity	Proposed BACT Limit	Proposed BACT Control
DU 21	Generator Engine	95 hp	0.031 lb/hp-hr	Good Combustion Practices Limited Operation (100 hours/year each, for non-emergency operation)
DU 22	Generator Engine	35 hp	0.031 lb/hp-hr	
DU 23	Generator Engine	155 hp	0.031 lb/hp-hr	
DU 24	Generator Engine	50 hp	0.031 lb/hp-hr	
DU 25	Generator Engine	18 hp	7.5 g/kW-hr	
DU 26	Generator Engine	68 hp	0.031 lb/hp-hr	
DU 27	Generator Engine	274 hp	4.0 g/kW-hr	
DU 28	Generator Engine	274 hp	4.0 g/kW-hr	
DU 30	Lift Pump Engine	75 hp	0.031 lb/hp-hr	
DU 32	Lift Pump Engine	75 hp	0.031 lb/hp-hr	
DU 33	Lift Pump Engine	75 hp	0.031 lb/hp-hr	
DU 34	Well Pump Engine	220 hp	0.031 lb/hp-hr	
DU 35	Well Pump Engine	55 hp	4.7 g/hp-hr	
DU 36	Well Pump Engine	220 hp	0.031 lb/hp-hr	
DU 29a	Lift Pump Engine	74 hp	4.7 g/kW-hr	
DU 31a	Lift Pump Engine	74 hp	4.7 g/kW-hr	
FWA 26	QSB7-G3 NR3	295 hp	4.0 g/kW-hr	
FWA 27	4024HF285B	67 hp	4.7 g/kW-hr	
FWA 28	CAT C9 GENSET	398 hp	4.0 g/kW-hr	
FWA 29	TM30UCM	47 hp	0.031 lb/hp-hr	
FWA 30	JW64-UF30	275 hp	4.0 g/kW-hr	
FWA 31	DDFP-04AT	235 hp	0.031 lb/hp-hr	
FWA 32	DDFP-04AT	235 hp	0.031 lb/hp-hr	
FWA 33	DDFP-04AT	235 hp	0.031 lb/hp-hr	
FWA 34	DDFP-04AT	235 hp	0.031 lb/hp-hr	
FWA 35	N-855-F	240 hp	0.031 lb/hp-hr	
FWA 36	N-855-F	240 hp	0.031 lb/hp-hr	
FWA 37	JU4H-UF40	94 hp	0.031 lb/hp-hr	
FWA 38	PDFP-06YT	120 hp	0.031 lb/hp-hr	
FWA 39	PDFP-06YT	120 hp	0.031 lb/hp-hr	

Table 6-2. Proposed PM-2.5 BACT Limits

EU ID	Description	Capacity	Proposed BACT Limit	Proposed BACT Control
DU 1	Six Coal Fired Boiler 3	230 MMBtu/hr	0.006 lb/MMBtu	Full stream baghouse
DU 2	Six Coal Fired Boiler 4	230 MMBtu/hr	0.006 lb/MMBtu	
DU 3	Six Coal Fired Boiler 5	230 MMBtu/hr	0.006 lb/MMBtu	
DU 4	Six Coal Fired Boiler 6	230 MMBtu/hr	0.006 lb/MMBtu	
DU 5	Six Coal Fired Boiler 7	230 MMBtu/hr	0.006 lb/MMBtu	
DU 6	Six Coal Fired Boiler 8	230 MMBtu/hr	0.006 lb/MMBtu	
FWA 8	Backup Diesel-Fired Boiler 1	19 MMBtu/hr	0.012 lb/MMBtu	Good Combustion Practices Limited Operation (600 hours/year combined) Combust ULSD
FWA 9	Backup Diesel-Fired Boiler 2	19 MMBtu/hr	0.012 lb/MMBtu	
FWA 10	Backup Diesel-Fired Boiler 3	19 MMBtu/hr	0.012 lb/MMBtu	
N/A	Diesel-Fired Boilers	Varies	0.012 lb/MMBtu	Good Combustion Practices Limited Operation (500 hours/year each, for non-emergency operation) Combust ULSD
DU 8	Generator Engine	2,937 hp	0.15 g/hp-hr	40 CFR 60 Subpart IIII Combust ULSD Good Combustion Practices Limited Operation (100 hours/year each, for non-emergency operation)
DU 10	Generator Engine	762 hp	0.15 g/hp-hr	
DU 11	Generator Engine	762 hp	0.15 g/hp-hr	
DU 13	Generator Engine	587 hp	0.15 g/hp-hr	
DU 15	Generator Engine	1,059 hp	0.32 g/hp-hr	Limited Operation (100 hours/year, for non-emergency operation) Good Combustion Practices Combust ULSD
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	

EU ID	Description	Capacity	Proposed BACT Limit	Proposed BACT Control
DU 9	Generator Engine	353 hp	2.20 E-3 lb/hp-hr	Limited Operation (100 hours/year each, for non-emergency operation) Good Combustion Practices Combust ULSD
DU 12	Generator Engine	82 hp	2.20 E-3 lb/hp-hr	
DU 14	Generator Engine	320 hp	0.2 g/kW-hr	
DU 16	Generator Engine	212 hp	2.20 E-3 lb/hp-hr	
DU 17	Generator Engine	176 hp	0.40 g/hp-hr	
DU 18	Generator Engine	212 hp	2.20 E-3 lb/hp-hr	
DU 19	Generator Engine	71 hp	0.4 g/kW-hr	
DU 20	Generator Engine	35 hp	2.20 E-3 lb/hp-hr	
DU 21	Generator Engine	95 hp	2.20 E-3 lb/hp-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	
DU 24	Generator Engine	50 hp	2.20 E-3 lb/hp-hr	
DU 25	Generator Engine	18 hp	0.4 g/kW-hr	
DU 26	Generator Engine	68 hp	2.20 E-3 lb/hp-hr	
DU 27	Generator Engine	274 hp	0.2 g/kW-hr	
DU 28	Generator Engine	274 hp	0.2 g/kW-hr	
DU 30	Lift Pump Engine	75 hp	2.20 E-3 lb/hp-hr	
DU 32	Lift Pump Engine	75 hp	2.20 E-3 lb/hp-hr	
DU 33	Lift Pump Engine	75 hp	2.20 E-3 lb/hp-hr	
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	0.03 g/kW-hr	
DU 31a	Lift Pump Engine	74 hp	0.03 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	

EU ID	Description	Capacity	Proposed BACT Limit	Proposed BACT Control
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	94 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	Proposed BACT Control
7a	South Coal Handling Dust Collector	0.0025 gr/dscf	Enclosed emission points and follow manufacturer recommendations for operations and maintenance
7b	South Underbunker Dust Collector	0.02 gr/dscf	Enclosed emission points and follow manufacturer recommendations for operations and maintenance
7c	North Coal Handling Dust Collector	0.02 gr/dscf	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	Chemical Stabilizers, Wind Fencing, Covered Haul Vehicles, Watering, and Wind Awareness
51a	Fly Ash Dust Collector	0.02 gr/dscf	Enclosed emission points and follow manufacturer recommendations for operations and maintenance
51b	Bottom Ash Dust Collector	0.02 gr/dscf	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	Proposed BACT Control
DU 1	Six Coal Fired Boiler 3	230 MMBtu/hr	0.10 lb/MMBtu	Dry Sorbent Injection Limited Operation (336,000 tons/year combined) Low Sulfur Coal
DU 2	Six Coal Fired Boiler 4	230 MMBtu/hr	0.10 lb/MMBtu	
DU 3	Six Coal Fired Boiler 5	230 MMBtu/hr	0.10 lb/MMBtu	
DU 4	Six Coal Fired Boiler 6	230 MMBtu/hr	0.10 lb/MMBtu	
DU 5	Six Coal Fired Boiler 7	230 MMBtu/hr	0.10 lb/MMBtu	
DU 6	Six Coal Fired Boiler 8	230 MMBtu/hr	0.10 lb/MMBtu	
FWA 8	Backup Diesel-Fired Boiler 1	19 MMBtu/hr	15 ppmv S in fuel	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	
N/A	Diesel-Fired Boilers	Varies	15 ppmv S in fuel	Limited Operation (500 hours/year each, for non-emergency operation) 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) Good Combustion Practices Combust ULSD
DU 10	Generator Engine	762 hp	15 ppmv S in fuel	
DU 11	Generator Engine	762 hp	15 ppmv S in fuel	
DU 13	Generator Engine	587 hp	15 ppmv S in fuel	
DU 15	Generator Engine	1,059 hp	15 ppmv S in fuel	
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 Combust ULSD
DU 12	Generator Engine	82 hp	15 ppmv S in fuel	
DU 14	Generator Engine	320 hp	15 ppmv S in fuel	
DU 16	Generator Engine	212 hp	15 ppmv S in fuel	
DU 17	Generator Engine	176 hp	15 ppmv S in fuel	
DU 18	Generator Engine	212 hp	15 ppmv S in fuel	
DU 19	Generator Engine	71 hp	15 ppmv S in fuel	

EU ID	Description	Capacity	Proposed BACT Limit	Proposed BACT Control
DU 20	Generator Engine	35 hp	15 ppmv S in fuel	Limited Operation (100 hours/year each, for non-emergency operation) Good Combustion Practices Combust ULSD
DU 21	Generator Engine	95 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	
DU 24	Generator Engine	50 hp	15 ppmv S in fuel	
DU 25	Generator Engine	18 hp	15 ppmv S in fuel	
DU 26	Generator Engine	68 hp	15 ppmv S in fuel	
DU 27	Generator Engine	274 hp	15 ppmv S in fuel	
DU 28	Generator Engine	274 hp	15 ppmv S in fuel	
DU 30	Lift Pump Engine	75 hp	15 ppmv S in fuel	
DU 32	Lift Pump Engine	75 hp	15 ppmv S in fuel	
DU 33	Lift Pump Engine	75 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 31a	Lift Pump Engine	74 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	
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	94 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	

From: Smith, Kristina A CIV USARMY IMCOM PACIFIC (USA)
To: Dec Air Comment
Cc: Heil, Cynthia L (DEC); Edwards, Alice L S (DEC); Dick, Eric M CIV USARMY USAG (USA)
Subject: ADEC Serious SIP Comments from Fort Wainwright (UNCLASSIFIED)
Date: Friday, July 26, 2019 10:04:42 AM
Attachments: ADEC Serious SIP Comment_Fort Wainwright.pdf

CLASSIFICATION: UNCLASSIFIED

Good Morning,

Please find an electronic copy of the comments Fort Wainwright has on the Serious SIP. The signed hard copy will also be sent in the mail.

Regards,
Kris

Kristina Smith
Air Program Manager
DPW - Environmental
U.S. Army Garrison Alaska
3023 Engineer Place
Fort Wainwright, AK 99703

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CLASSIFICATION: UNCLASSIFIED

DEPARTMENT OF THE ARMY
INSTALLATION MANAGEMENT COMMAND
HEADQUARTERS, U.S. ARMY GARRISON ALASKA
1046 MARKS ROAD #6000
FORT WAINWRIGHT, ALASKA 99703-6000

REPLY TO ATTENTION OF:

RECEIVED
JUL 26 2019

Directorate of Public Works

Alaska Department of Environmental Conservation
Division of Air Quality
ATTN: Cindy Heil
555 Cordova St.
Anchorage, AK 99501

To Whom This Concerns:

On 13 May 2019, the Alaska Department of Environmental Conservation (ADEC) issued the draft Serious State Implementation Plan (SIP) and requested comments no later than 27 July 2019. United States Army Garrison Alaska (USAG Alaska) has reviewed the Serious SIP and has made comments to ensure correct information is used in the evaluation of control strategies that Fort Wainwright would be subject too upon the Environmental Protection Agency (EPA) approval of the plan. Fort Wainwright appreciates the opportunity to comment on this serious SIP.

All comments contained within this letter address the ADEC Serious SIP draft document section titled Volume II; III.D.7.7 Control Strategies.

Comment 1: Section 7.7.8.3 Fort Wainwright

Please reword the sentence: "The EUs located within the military installation at Fort Wainwright Central Heating and Power Plant (CHPP) are operated by a private utility company, Doyon Utilities, LLC. (DU) and owned by the U.S. Army Garrison Fort Wainwright (FWA)" to "EUs located within the military installation include units such as boilers and generators that are owned and operated by the U.S. Army Garrison Alaska (FWA). The FWA Central Heating and Power Plant (CHPP), also located within the installation footprint, is owned and operated by a private utility company, Doyon Utilities, LLC (DU)."

The current wording suggests that DU operates all of the emission units (EUs) located within the installation footprint, which is misleading and inaccurate. DU also owns the CHPP, not Fort Wainwright. U.S. Army Garrison Fort Wainwright is now United States Army Garrison Alaska.

Comment 2: Section 7.7.8.3 Fort Wainwright, applies throughout the section

Several emission units were transferred between DU and Fort Wainwright at the beginning of 2019. The following corrections should be made to accurately reflect EU ownership and which entity has requirements to comply with: DU EU 10 is now FWA EU 50; DU EU 11 is now FWA EU 51; DU EU 12 is now FWA EU 52; DU EU 13 is now FWA EU 53; DU EU 15 is now FWA EU 54; DU EU 16 is now FWA EU 55; DU EU 17 is now FWA EU 56; DU EU 18 is now FWA EU 57; DU EU 19 is now FWA EU 58; DU EU 20 is now FWA EU 59; DU EU 21 is now FWA EU 60; DU EU 24 is now FWA EU 61; DU EU 25 is now FWA EU 62; DU EU 26 is now FWA EU 63; DU EU 27 is now FWA EU 64; and DU EU 28 is now FWA EU 65.

Comment 3: Section 7.7.8.3.1 NOx Controls for Fort Wainwright, Last Paragraph

"Limit EU 8 to 500 hours of operation per year." Please clarify which EU 8 is being referred to here: FWA EU 8 or DU EU 8?

Comment 4: Section 7.7.8.3.1 NOx Controls for Fort Wainwright

"Limit non-emergency operation of the 27 diesel fired boilers, with the exception of the waste-fuel boilers, to no more than 500 hours per year, for maintenance checks and readiness testing."

In reviewing this requirement, there is a misstated assumption in the Fort Wainwright Best Available Control Technologies (BACT) Analysis that states that the boilers are emergency boilers. The only emergency boilers in use on Fort Wainwright are EUs 8, 9, and 10. All other boilers in the emissions inventory are considered insignificant emission sources and are not used for emergency purposes, as they are the primary heating source at their designated building identifier. Limiting boilers to 500 hours would affect Army readiness and create problems with maintaining mission important infrastructure during seasonally cold temperatures.

Comment 5: Section 7.7.8.3.2 PM2.5 Controls for Fort Wainwright

"Limit non-emergency operation of the 27 diesel fired boilers, with the exception of the waste-fuel boilers, to no more than 500 hours per year, for maintenance checks and readiness testing."

In reviewing this requirement, there is a misstated assumption in the Fort Wainwright BACT Analysis that states that the boilers are emergency boilers. The only emergency boilers in use on Fort Wainwright are EUs 8, 9, and 10. All other boilers in the emissions inventory are considered insignificant emission sources and are not used for emergency purposes, as they are the primary heating source at their designated building identifier. Limiting boilers to 500 hours would affect Army readiness and create problems with maintaining mission important infrastructure during seasonally cold temperatures.

Comment 6: Section 7.7.8.3.3 SO_2 Controls for Fort Wainwright

"Limit non-emergency operation of the 27 diesel fired boilers, with the exception of the waste-fuel boilers, to no more than 500 hours per year, for maintenance checks and readiness testing."

In reviewing this requirement, there is a misstated assumption in the Fort Wainwright BACT Analysis that states that the boilers are emergency boilers. The only emergency boilers in use on Fort Wainwright are EUs 8, 9, and 10. All other boilers in the emissions inventory are considered insignificant emission sources and are not used for emergency purposes, as they are the primary heating source at their designated building identifier. Limiting boilers to 500 hours would affect Army readiness and create problems with maintaining mission important infrastructure during seasonally cold temperatures.

Comment 7: Section DEC BACT DETERMINATION for Fort Wainwright Central Heating and Power Plant

Based on a review of the control package and the BACT analyses for the other two coal fired facilities located in the nonattainment area, the economic feasibility argument finding should equitably apply to all coal fired facilities in the nonattainment area. There is no articulated argument stating why the Fort Wainwright CHHP is required to have additional controls or why it is dissimilar to the other coal power plants that are subject to the same requirements. The Fort Wainwright CHHP is a coal fired plant with the same or similar processes as the Chena Power Plant and the UAF Power Plant, and would be subject to the same proposed coal sulfur limitations. Studies completed by EPA in 2016, as highlighted in Vol. II: III.D.7.8 Modeling document, states that wood smoke contributes between 60-80% of the fine particulate matter found on filters during the winter months, while major sources contribute less than 10%. Installation of costly controls on an aging facility may that have little to no influence on the air quality in the nonattainment area, where wood smoke is identified as the major primary contributor.

Additionally, Fort Wainwright is assessing future energy usage based on aging infrastructure and is developing plans for improvement or replacement of current utilities, which has a projected timetable of less than 15 years. As such, Fort Wainwright requests that an Economic Infeasibility determination be applied to the Fort Wainwright CHHP.

If you desire further information, please contact Kristina Smith, USAG Alaska, Air Quality Program Manager at (907) 361-9687 or at kristina.a.smith14.civ@mail.mil.

Sincerely,

Christopher J. Ruga
Colonel, US Army
Commanding

From:	Isaac Jackson
To:	Dec Air Comment
Cc:	Dan Gavora; Shayne Coiley; Ed Stevenson; Kathleen Hook; Josh Van Horn; Stringham, Stephen D CIV (US); "fred.o.sandgren.civ@mail.mil"
Subject:	Doyon Utilities Serious SIP BACT Analysis Comments [CO 19-067]
Date:	Friday, July 26, 2019 12:46:04 PM
Attachments:	DU Serious SIP BACT Comments 7.26.19_CO_19_067.pdf

Attached find comments on the proposed Serious SIP for Fairbanks area PM 2.5 regarding the proposed BACT analysis of Doyon Utilities emission units permitted under AQ1121TVP02 Rev 2.

Any questions contact Isaac Jackson at (907) 455-1547 or ijackson@doyonutilites.com .

From: Isaac Jackson
To: Dec Air Comment
Cc: Dan Gavora; Shayne Coiley; Ed Stevenson; Kathleen Hook; Josh Van Horn; Stringham, Stephen D CIV (US); "fred.o.sandgren.civ@mail.mil"
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Any questions contact Isaac Jackson at (907) 455-1547 or ijackson@doyonutilites.com .

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DOYON UTILITIES LLC

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PO Box 74040
Fairbanks, AK 99707

July 26, 2019

Cindy Heil
Alaska Department of Environmental Conservation
Division of Air Quality
555 Cordova St
Anchorage, AK 99501

Re: Comments Addressing the Proposed Best Available Control Technology Determination for Fort Wainwright US Army Garrison and Doyon Utilities

Dear Ms. Heil:

Doyon Utilities, LLC (DU) provides the enclosed comments addressing the proposed Best Available Control Technology (BACT) assessment that the Alaska Department of Environmental Conservation (ADEC) has prepared for Doyon Utilities' Fort Wainwright Privatized Utilities. DU has limited this review and comment effort to those emissions units that are owned and operated by DU and that are included in Title V Permit AQ1121TVP02, Revision 2. DU has not provided comments addressing emissions units that are owned and operated by the US Army Garrison.

On May 23, 2018, DU provided comments addressing the preliminary BACT documents. On May 10, 2019, ADEC opened the official public comment period for the proposed BACT. The comments and information included in the materials accompanying this letter are directed to the proposed BACT in accordance with ADEC's invitation for public comment.

The attached comments (Attachment 1) identify a number of concerns with the proposed BACT. The following concerns are particularly important to note:

- The preliminary SIP identifies US Army Garrison Fort Wainwright as the owner of the Central Heat and Power Plant on Fort Wainwright. However, DU owns and operates the CHPP. DU's responsibilities as owner and operator are reflected in regulation by the Regulatory Commission of Alaska (CPCN #725); environmental permits with ADEC (most recently AQ1121TVP02); easement by the U.S. Army Corps of Engineers; and a 50-year contract between DU and the Department of Defense.
- The preliminary SIP proposes DSI as SO_2 BACT. DU notes that the basis for this proposal is reliance on a cost model that is not appropriate for the size of the boilers, and appears to be premised on other incorrect or unsupported assumptions. As noted in DU's comments,

DU contracted with Black and Veatch (B&V) to prepare a rough-order-of-magnitude cost estimate for a DSI system to be installed at the CHPP's Wainwright six boilers. DU's estimate is twice the ADEC cost estimate. The proposed SO_2 controls are not economically feasible.

- The CHPP baghouse $PM_{2.5}$ BACT emission limits are provided without supporting rationale, may not be appropriate as $PM_{2.5}$ emission limits, and/or may not be achievable.
- The preliminary $PM_{2.5}$ BACT analysis for the material handling of the coal handling emissions units (EUs 7a, 7b, 7c, 51a, 51b, and 52) are unclear and may not be achievable with current configuration.
- The preliminary SIP does not reflect a generator asset transfer of several generator engines from DU to the Army in late December 2018. See Attachment 2 for a copy of this notification.

DU confirms its commitment to working with ADEC to address any questions or issues that our foregoing comments may raise. Please contact Kathleen Hook at khook@doyonutilities.com if you have any questions or would like to further discuss any specific comments.

Best Regards,

Shayne Coiley

Shayne Coiley
Senior Vice President
Doyon Utilities, LLC

cc: S. Koessel, DLA Energy
S. Stringham, Utility Chief, FWA Garrison
F. Sandgren, COR, FWA Garrison
D. Burgess, COR, FWA Garrison
P. Marvin,COR FWA Garrison

Attachment 1 Doyon Utilities' Comments Addressing the Proposed Best Available Control Technology Determination for Fort Wainwright Privatized Utilities Dated May 10, 2019

Attachment 2 DU correspondence dated December 31, 2018 notifying ADEC of a generator asset transfer from DU to the Army at Ft Wainwright

CO 19-067

Attachment 1

Doyon Utilities' Comments Addressing the Proposed Best Available Control Technology Determination for Fort Wainwright Privatized Utilities Dated May 10, 2019

Doyon Utilities' Comments Addressing the Proposed Best Available Control Technology Determination for Fort Wainwright Privatized Utilities Dated May 10, 2019

On May 10, 2019, ADEC published proposed the Serious State Implementation Plan ("Serious SIP" or "SIP"). The SIP proposed amendments to 18 AAC 50.030 that would adopt the new section in Volume II, Section III.D.7: Fairbanks North Star Borough (FNSB) Fine Particulate Matter (PM-2.5). Interested parties and members of the public were invited to submit comment to the SIP.

Doyon Utilities, LLC (DU) herein submits comments addressing the documents that will revise the State Air Quality Control Plan. DU specifically comments on the following elements of the proposed SIP revisions:

- Amendments to State Air Quality Control Plan Volume II: III.D.7.7 Control Strategies, Draft, May 10, 2019. [Referred to below as "proposed SIP document."]
- "Fort Wainwright US Army Garrison and Doyon Utilities BACT Documents" in the Draft Amendments to State Air Quality Control Plan Vol. III: Appendix III.D.7.07, May 10, 2019. [Referred to below as "proposed BACT Determination."]

General Comments

1. Section 7.7.8.3 of the proposed SIP document states incorrectly that the Fort Wainwright (FWA) Central Heat and Power Plant (CHPP) emissions units "are operated by a private utility company, Doyon Utilities, LLC (DU) and owned by the US Army Garrison Fort Wainwright."

   The Central Heat and Power Plant (CHPP) was owned and operated by the Department of Defense until formally transferred to Doyon Utilities on August 15, 2008. Prior to transfer, Department of Defense solicited proposals for privatization of the CHPP and other electric and steam utility assets. DU was the successful bidder and signed a 50-year contract on September 28, 2007 to become the new owner and operator. For more than ten years, Doyon Utilities has owned and operated the plant under the economic jurisdiction of the Regulatory Commission of Alaska Certificate of Public Convenience and Necessity #725. Under the regulated model, DU recovers operating and capital costs through rates established by the RCA. In addition to economic regulation, DU is subject to environmental regulation as well. DU has held a series of air permits from ADEC for the emissions units in the CHPP. The Army does not maintain a physical presence at any of DU's facilities, nor is the Army responsible for day to day operational discussions. As the customer who pays for utility services via tariff rates, the Army is interested in compliance issues of DU's facilities.

2. Section 7.7.8.3 of the proposed SIP document and Tables A and B of the proposed Best Available Control Technology (BACT) Determination do not reflect the asset transfer of several generator engines from DU to the Army in late December 2018. The documents identify those engines as DU emissions units instead of Army garrison emissions units. DU submitted a notification of these changes to the Alaska Department of Environmental Conservation (ADEC) on December 31, 2018. See Attachment 2 for a copy of this notification.

3. In some instances, the proposed SIP document and the underlying proposed BACT Determination are inconsistent with respect to applicable emissions limits and other requirements. Because both documents will become part of the SIP, please ensure that these two documents are internally consistent and clearly state which requirements are applicable to each emissions unit. DU has attempted to address specific inconsistencies in the subsequent comments.

BACT for Nitrogen Oxides (NO_X)

In Section 7.7.8.3.1 of the proposed SIP document, ADEC states that "the NO_X controls proposed in this section are not planned to be implemented." In the event that the U.S. Environmental Protection Agency (EPA) does not approve the precursor demonstration as justification not to require NO_X controls, DU provides the following comments on the proposed NO_X BACT determination and associated SIP requirements.

4. If NO_X BACT is required, the proposed BACT for the CHPP coal-fired boilers, Emissions Units 1 through 6, is selective catalytic reduction (SCR). The proposed emission limit is 0.060 pounds per million British thermal units (lb/MMBtu) averaged over three hours. The proposed SIP document and supporting proposed BACT Determination do not provide engineering design data supporting this emission limit for these boilers. How did ADEC determine that this emission limit was appropriate? The calculation of the emission limit is based on a 90 percent reduction in NO_X emissions compared to the baseline. A 90 percent reduction is the typical maximum reduction that can be expected from the use of SCR. However, no specific engineering information is presented to support the conclusion that a 90 percent NO_X emission reduction is achievable for the DU CHPP boilers, particularly in light of the economic analysis discrepancies, addressed below.

5. The economic analysis spreadsheet[1] is a cost model offered to support the SCR BACT determination. The cost model was developed by Sargent & Lundy (S&L) but does not appear to be an appropriate model for costs pertaining to the DU CHPP boilers. Additionally, the inputs to the cost model may not be appropriate or adequate to properly determine costs.

   DU reviewed the cost effectiveness model and supporting documentation. The validity of the model cannot be confirmed based on the information that ADEC made available in the public record. From what is available in the public record, DU can note three assumptions in the model that do not look appropriate as applied to DU.

   - ADEC assumed that the model is valid for a plant the size of DU's CHPP.
     - The S&L SCR Cost Development Methodology[2] white paper dated January 2017 addresses several caveats which are not identified or addressed in the draft BACT Determination. The white paper states that "the costs for retrofitting a plant smaller than 100 megawatts (MW) increase rapidly due to the economy of size. S&L is not aware of any SCR installations in recent years for smaller than 100-MW units." The draft BACT Determination does not

[1] 2019-05-10-adec-calculated-scr-economic-analysis-for-wainwright.xlsm
[2] https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-3_scr_cost_development_methodology.pdf

appear to adjust for the expected increased costs for retrofitting smaller plants such as the DU CHPP. DU's CHPP boilers each have a maximum heat input rate of 250 MMBtu/hr which is an equivalent maximum input of approximately 75 MW. The DU CHPP boilers have an output significantly less than 100 MW. As a result, as noted in the S&L white paper, the cost model should have been adjusted for size; because the adjustment was not made, the cost model would underestimate emissions control costs for EUs 1 through 6.
  - The S&L white paper states that older units typically have limited space in which to add an SCR reactor and associated ductwork, and that the existing fans may not be sufficient to overcome the added pressure drop. The proposed BACT determination does not discuss these concerns. Whether the cost model as applied by ADEC accounts for these issues is unclear. DU readily confirms there would be significant design confirms for physical space and fan capacity if the boilers were to be retrofitted with SCR.

- The proposed BACT Determination assumes that multiple boilers can accurately be modeled using a totaled heat input in a single spreadsheet.
  - The S&L white paper states that "a combined SCR for small units is not a feasible option." Each boiler requires a single, dedicated SCR reactor due to the needed heat recovery.
  - Review of the spreadsheet provided by ADEC, reflects the proposed BACT considers EUs 1 thorough 6 as a single, lumped heat input value. This approach is an oversimplification and will not accurately account for the equipment and utilities necessary to independently operate six boilers. The actual installation will require six separate trains of reagent processing and transport equipment. Each train contains a various feeders, blowers, coolers, hoppers, piping, instrumentation, controls, electrical wiring and other supporting equipment. This need for separate systems complicates the design, increases overall footprint, and reduces the economy of scale that might be realized with a single larger unit.

- ADEC assumed that the model is valid for a heat and power plant.
  - No information is available addressing the type of plant on which the S&L spreadsheet is based. It appears S&L assumed that the plant is a single power generation unit. However, a combined heat and power (CHP) plant differs significantly from a "traditional" power plant in that the steam produced in a CHP plant is not exclusively used to generate electricity. DU is unable to confirm that the direct annual costs can be accurately modeled for an installation such as the DU's EUs 1 through 6 by using the S&L spreadsheet.

6. Section 3.3 in the proposed BACT Determination for large diesel-fired engines, specifically Step 5(c), states that non-emergency operation of EU 8 is limited to "no more than 100 hours per year for maintenance checks and readiness testing." This requirement is inconsistent with Title V Permit AQ1121TVP02, Revision 2 which allows EU 8 to be converted to a non-emergency engine with a limit of 500 hours per year. (Please refer to Conditions 24.3 through 24.6 of that permit). Please revise this requirement to clarify that the limit applies only while the engine is classified as an emergency engine, and that the limit is not inconsistent with applicable requirements under 40 Code of Federal Regulations (CFR) 60 Subpart IIII, which allows 100 hours per year of non-emergency operation but does not restrict those non-emergency operations to maintenance checks and readiness testing. (Please refer to Condition 23.3c of Permit AQ1121TVP02, Revision 2 and 40 CFR

60.4211(f)(3).) Please align the BACT requirements to be consistent with the existing applicable permit requirements and ensure that Section 7.7.8.3.1 of the proposed SIP document is revised for consistency with the underlying proposed BACT Determination.

7. Please include a statement in Section 3.3 of the proposed BACT Determination and Section 7.7.8.3.1 of the proposed SIP document to clarify that EU 8 shall demonstrate compliance with the numerical BACT emission limit by complying with the applicable NO_X emission standard in 40 CFR 60 Subpart IIII.

8. Section 3.4 in the proposed BACT Determination for small diesel-fired engines, specifically Step 5(a), states that non-emergency operation of the small emergency engines is limited to "no more than 100 hours per year for maintenance checks and readiness testing." Please revise this requirement to clarify that the limit is not inconsistent with applicable requirements under 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ, which allow 100 hours per year of non-emergency operation but does not restrict those non-emergency operations to maintenance checks and readiness testing. (Please refer to Conditions 23.3c and 30.3 of Permit AQ1121TVP02, Revision 2, 40 CFR 60.4211(f)(3), and 40 CFR 63.6640(f).) Please align the BACT requirements to be consistent with the existing applicable permit requirements and ensure that Section 7.7.8.3.1 of the proposed SIP document is revised for consistency with the underlying proposed BACT Determination.

9. Section 7.7.8.3.1 of the proposed SIP document states that BACT for NO_X emissions from the small diesel-fired engines includes the requirement that "for engines manufactured after the applicability dates of 40 CFR 60 Subpart IIII, comply with the applicable NO_X emissions factors in 40 CFR 60 Subpart IIII." DU believes that ADEC intended to require that the engines subject to 40 CFR 60 Subpart IIII shall comply with the applicable NO_X <u>emission standard</u> in that rule.

10. Table 3-11 of the proposed BACT Determination indicates that all of the small diesel-fired engines are subject to a numerical NO_X emission limit. Section 7.7.8.3.1 of the proposed SIP document does not provide numerical emission limits for those engines not subject to 40 CFR 60 Subpart IIII. Please ensure that the underlying proposed BACT determination and the proposed SIP document are consistent to minimize possible confusion, and that the documents clearly state the compliance demonstration method.

<u>BACT for Fine Fraction Respirable Particulate Matter (PM-2.5)</u>

11. Section 7.7.8.3.2 of the proposed SIP document and Section 4.1 of the proposed BACT Determination establish a PM-2.5 emission limit for EUs 1 through 6 of 0.006 pounds per million British thermal units (lb/MMBtu). ADEC has not provided a sound rationale for this determination and the PM-2.5 BACT emission limit. DU does not have PM-2.5 source test data for these boilers and is concerned that this limit may be unreasonably low, restrictive, and not achievable as a practical matter.

    - **The basis for this limit is a source test for a different air pollutant.** The PM-2.5 BACT limit of 0.006 lb/MMBtu is based on one source test run from a three-run test conducted on EU 1 at

Fort Wainwright in April 2017. This source test was an EPA Method 5 test, which measures filterable particulate matter (PM). PM includes all filterable particulate matter regardless of size. PM-2.5 includes filterable particulate matter with a nominal aerodynamic diameter of 2.5 microns or less. PM-2.5 also includes all condensable matter while PM does not include any condensable matter. The proposed BACT Determination states that the lowest PM-2.5 emission rate listed in the RBLC (RACT BACT LAER Clearinghouse database) is 0.012 lb/MMBtu. The BACT emission limit being imposed is an order of magnitude less than the lowest emission rate cited in the RBLC. No rationale or supporting engineering data are provided to justify this low emission limit, or to explain the reasons ADEC believes the limit is achievable.

- **The basis for this limit is one source test run on one boiler.** Relying on one run from one source test is an inappropriate method to establish an emission limit for any purpose. While DU appreciates that ADEC was attempting to select the worst-case run, using data from one run instead of the source test result is not appropriate or standard practice.

- **If ADEC wished to rely on source testing to establish PM-2.5 limits for the coal-fired boilers, ADEC should have conducted or requested source testing for PM-2.5 emissions while adequate time was available to do so.** Neither Section 7.7 of the proposed SIP document nor the underlying proposed BACT Determination explain the reasons the PM source test result is representative of the PM-2.5 emission rate. If the assumption is being made that PM-2.5 emissions from EUs 1 through 6 are less than or equal to PM emissions, this assumption should be supported (with source test results) to confirm that compliance with the limit can be achieved. Otherwise, please explain the rationale for selecting a PM-2.5 emission rate of 0.006 lb/MMBtu as the PM-2.5 BACT emission limit for EUs 1 through 6.

- In comments dated May 23, 2018, DU noted that the appropriateness of using a filterable PM emission limit to establish a PM-2.5 BACT limit had not been established. These comments were submitted to address the preliminary BACT Determination issued by ADEC in March 2018. ADEC does not appear to have considered this information in reaching the BACT determination. DU is requesting clarification from ADEC regarding whether the previously submitted information listed below was included in the BACT evaluation. If yes, DU is requesting clarification with respect how the information was considered. If no, DU is requesting clarification with respect to the reasons the information was not considered.

- During review of these proposed SIP elements, DU reviewed a spreadsheet file "Fbks_PtSrcs_2013-2019_Episode_Inventories_ToSLR.xlsm," described by Trinity Consultants as "A version of our comprehensive point source episodic EI calculation spreadsheet with 2013-2019 EI data. This spreadsheet references facility specific spreadsheets with hourly episodic emission or fuel/throughput rates from the original 2008 episodes." In that spreadsheet, DU noted that ADEC and Trinity appeared to use a PM-2.5 emission factor of 0.697 pounds per ton of coal (lb/ton) to calculate PM-2.5 emissions from EUs 1 through 6 in certain tables. DU calculated this emission factor from data in Tables 1.1-5 and 1.1-6 in AP-42. The emission factor has been used to calculate potential assessable PM-2.5 emissions for EUs 1 through 6 in the two most recent Title V permit renewal applications (submitted in May 2013 and April 2019). The spreadsheet also includes tabs that show much lower PM-2.5 emission rates. DU is requesting clarification regarding the method used to calculate those lower rates and which emissions factors were used. BACT limits must be achievable in practice. As a result, DU requests that ADEC revisit the PM-2.5 BACT analysis using the appropriate available information to establish a PM-2.5 BACT limit that is well-supported with respect to being technically and economically feasible as well as achievable as a practical matter.

- The proposed SIP includes PM2.5 emission limits for EUs 7a, 7b, 7c, 51a, 51b and requires each EU to be source tested to demonstrate compliance. EUs 7a and 7c have been source tested previously but certain modification to the test method were needed due to space constraints. DU does not know whether the configurations of EUs51 and 51b are conducive to conducting a PM2.5 source test.

12. Section 4.3 in the proposed BACT Determination has an inconsistent rationale for the BACT requirement to combust ultra-low sulfur diesel (ULSD) in large diesel-fired engines. (Specifically, this comment addresses privatized EU 8, the backup generator engine at the CHPP.)
    - In Step 1(d), the use of low sulfur fuel is listed as an available and feasible emission control technology.
    - Step 2 states that all control technologies identified are technically feasible to control particulate emissions from large diesel-fired engines. DU notes that the use of low sulfur fuel is technically feasible, but the contribution of this technology toward reducing PM-2.5 emissions cannot be quantified.
    - Step 3 does not address the use of ULSD.
    - Step 5(d) requires the use of ULSD, with no supporting rationale or cost analysis.

    Please make appropriate revisions to Section 4.3. DU understands that the requirement to combust ULSD will likely remain unchanged for the large diesel-fired engine. Specifically, the sulfur dioxide (SO_2) BACT decision also requires the use of ULSD, so correcting this inconsistency in Section 4.3 will not eliminate the requirement to combust ULSD in the large diesel-fired engine. The combustion of ULSD is required in the large diesel-fired engines that are subject to 40 CFR 60 Subpart IIII.

13. Section 4.3 in the proposed BACT Determination does not provide a cost analysis to support the proposed PM-2.5 BACT determinations identified in Step 5 for large diesel-fired engines. Because each BACT determination must be based on technical and economic feasibility, the rationale for these proposed BACT determinations is incomplete, making the validity of the determinations questionable. Please include the required economic feasibility analysis.

14. Please include a statement in Section 4.3 of the proposed BACT Determination and Section 7.7.8.3.2 of the proposed SIP document to clarify that EU 8 shall demonstrate compliance with the numerical BACT emission limit by complying with the applicable PM emission standard in 40 CFR 60 Subpart IIII.

15. Section 4.3 in the proposed BACT Determination for large diesel-fired engines, specifically Step 5(c), states that non-emergency operation of EU 8 is limited to "no more than 100 hours per year for maintenance checks and readiness testing." This requirement is inconsistent with Title V Permit AQ1121TVP02, Revision 2 which allows EU 8 to be converted to a non-emergency engine with a limit of 500 hours per year. (Please refer to Conditions 24.3 through 24.6 of that permit). Please revise this requirement to clarify that the limit applies only while the engine is classified as an emergency engine, and that the limit is not inconsistent with applicable requirements under 40 CFR 60 Subpart IIII, which allows 100 hours per year of non-emergency operation but does not restrict those non-emergency operations to maintenance checks and readiness testing. (Please refer to Condition 23.3c of AQ1121TVP02, Revision 2 and 40 CFR 60.4211(f)(3).) Please align the BACT requirements to be consistent with the existing applicable permit requirements and ensure that Section 7.7.8.3.2 of the proposed SIP document is revised for consistency with the underlying proposed BACT Determination.

16. Table 4-9 in Section 4.4 of the proposed BACT Determination includes a PM-2.5 BACT limit of 0.03 grams per kilowatt-hour (g/kW-hr) for EUs 29a and 31a. This limit appears to reflect the EPA Tier 4 final PM emission standard. EUs 29a and 31a are both certified to EPA Tier 4 interim standards. The applicable Tier 4 interim PM standard is 0.3 g/kW-hr. Please revise Table 4-9 to reflect the appropriate emission limit for these Tier 4 interim-certified engines.

17. Section 4.4 in the proposed BACT Determination for small diesel-fired engines, specifically Step 5(b), states that non-emergency operation of the small emergency engines is limited to "no more than 100 hours per year for maintenance checks and readiness testing." Please revise this requirement to clarify that the limit is not inconsistent with applicable requirements under 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ, which allow 100 hours per year of non-emergency operation but does not restrict those non-emergency operations to maintenance checks and readiness testing. (Please refer to Conditions 23.3c and 30.3 of AQ1121TVP02, Revision 2, 40 CFR 60.4211(f)(3), and 40 CFR 63.6640(f).) Please align the BACT requirements to be consistent with the existing applicable permit requirements and ensure that Section 7.7.8.3.2 of the proposed SIP document is revised for consistency with the underlying proposed BACT Determination.

18. Section 4.4 in the proposed BACT Determination has an inconsistent rationale for the BACT requirement to combust ultra-low sulfur diesel (ULSD) in small diesel-fired engines.
    - Step 1 does not identify the use of low sulfur fuel or ULSD an available emission control technology.
    - Step 3 ranks low sulfur fuel in the list of technically feasible control technologies. The use of low sulfur fuel is technically feasible, but the contribution of this technology toward reducing PM-2.5 emissions cannot be quantified.
    - Step 5(a) requires the use of ULSD, with no supporting rationale or cost analysis.

    Please make appropriate revisions to Section 4.4. DU understands that the requirement to combust ULSD will likely remain unchanged for the small diesel-fired engines. Specifically, the SO_2 BACT decision also requires the use of ULSD, so correcting this inconsistency in Section 4.4 will not eliminate the requirement to combust ULSD in the small diesel-fired engines.

19. Section 4.4 in the proposed BACT Determination does not provide a cost analysis to support the proposed PM-2.5 BACT determinations identified in Step 5 for small diesel-fired engines. Because each BACT determination must be based on technical and economic feasibility, the rationale for these proposed BACT determinations is incomplete, making the validity of the determinations questionable. Please include the required economic feasibility analysis.

20. Section 7.7.8.3.2 of the proposed SIP document states that BACT for PM-2.5 emissions from the small diesel-fired engines includes the requirement that "for engines manufactured after the applicability dates of 40 CFR 60 Subpart IIII, comply with the applicable PM-2.5 emissions factors in 40 CFR 60 Subpart IIII." DU believes that ADEC intended to require that the engines subject to 40 CFR 60 Subpart IIII shall comply with the applicable PM emission standard in that rule. (The rule does not include PM-2.5 emission standards.)

21. Table 4-9 of the proposed BACT Determination indicates that all of the small diesel-fired engines are subject to a numerical PM-2.5 emission limit. Section 7.7.8.3.2 of the proposed SIP document does not provide numerical emission limits for those engines not subject to 40 CFR 60 Subpart IIII. Please ensure that the underlying proposed BACT determination and the proposed SIP document are consistent to minimize possible confusion, and that the documents clearly state the compliance demonstration method.

BACT for SO_2

22. In Section 5.1 of the proposed BACT Determination, Table 5.3 specifies SO_2 cost effectiveness for wet scrubbing and spray dry absorbers to be \$20,673 per ton SO_2 removed and \$21,211 per ton SO_2 removed, respectively. Although not explicitly stated, the proposed BACT Determination implies that these two technologies are not economically feasible and so are not SO_2 BACT. While DU has not evaluated the cost estimates for these control technologies, DU agrees that wet scrubbing and spray dry absorbers are not SO_2 BACT. As a result, comments addressing wet scrubbing or spray dry absorbers are not presented in this document.

    The preliminary proposed SO_2 BACT is dry sorbent injection (DSI) which the proposed BACT Determination states at a capital cost of \$14.5 million has a cost effectiveness of \$10,329 per ton SO_2 removed. DU is concerned that the analysis is based on unsupported assumptions and use of a cost model that may not be appropriate for the size of the boilers.

    As a result, DU contracted with Black and Veatch (B&V) to prepare a rough-order-of-magnitude cost estimate for a DSI system to be installed at DU's CHPP six boilers. B&V was selected not only because of their experience performing engineering services on projects in Alaska for electric utilities and the US military, but the fact that they are familiar with the CHPP as a result of a 2017/2018 Heat and Energy Study.

B&V used 0.25% coal sulfur content, assumed a building enclosure for all pieces of equipment, including the silos due to the cold Fairbanks temperatures, and developed capital costs for two different types of sorbent. Trona capital costs are less expensive than sodium bicarbonate, but ongoing operation costs are higher due to the higher sorbent injection rate and cost of sorbent delivery to Fairbanks. With the addition of owner costs, DU estimates that depending on the selected sorbent selection, initial capital costs can range between $26.1 and $31.6 million. This far exceeds ADEC's estimate of $14.5 million. DU's estimate is twice the ADEC cost estimate, and believes that SO_2 controls are not economic feasible.

In addition to the B&V analysis, DU provides the following comments on the SIP DSI analysis;

- Cost Model Validity: The economic analysis spreadsheet[3] containing the cost-effectiveness calculations for the proposed SO_2 BACT determination was originally developed by Sargent & Lundy (S&L) in 2010. The spreadsheet includes a link to the S&L white paper that provides a basis for the calculations that are in Row 25 of the spreadsheet. The S&L white paper states that the model is intended to calculate estimated Total Project Cost (total capital cost of installation), as well as direct and indirect annual operating costs. These calculations are largely based on the estimated usage of sorbent (in this case Trona) on a tons per hour (tph) basis and the gross generating capacity of the plant. The white paper omits information that is necessary to ensure that the spreadsheet is properly applied to a specific situation, including:
  - Types of plants to which the model is applicable (utility power generation, combined heat and power (CHP), cogeneration, other);
  - Applicable number of boilers (single unit or multi-boiler installation);
  - Applicable size range;
  - Equipment included in the Total Purchased Cost (TPC) calculation;
  - On-site bulk storage capacity;
  - A basis for selecting a "Retrofit factor" other than "1.0"; and
  - Data and other information used to develop and support the equations used in the spreadsheet.

  Based on review of the cost effectiveness model and the supporting documentation, determining the validity of the results of the analysis is not possible given the information that ADEC has made available in the public record. The concerns are rooted in three assumptions made by ADEC in preparing the cost model.

- ADEC assumed that the model is valid for a plant the size of DU's Wainwright CHPP.
  - The calculation for "Base Module" cost (Row 30 of the spreadsheet) is based on an equation that uses the predicted sorbent demand. The S&L white paper states that the equation was developed based on "Cost data for several DSI systems." No references or supporting information relating to these projects were provided. While the validity range for the equation was not identified, one piece of information gives some indication of the applicable range. Specifically, the equation has a discontinuity at 25 tph of sorbent flow. Given that the predicted total sorbent flow for all six coal-fired boilers at DU's Wainwright CHPP is 1.5 tph,

[3] 2019-05-10-adec-calculated-so2-economic-analysis-fort-wainwright-locked.xlsx

these boilers would be at the very bottom of the range of potential plant sizes. Without additional data to justify the cost calculation at very low sorbent injection rates, determining if the results of the equation are accurate is very difficult.

- The Preliminary Determination assumes that multiple boilers can accurately be modeled as a lumped heat input in a single spreadsheet.
    - The S&L white paper does not identify the type or configuration of the plant on which the calculation was based. Data input fields included in the spreadsheet (unit size, gross heat rate) indicate that the analysis was developed based on a single power generation unit (single boiler, single steam turbine, no CHP or cogeneration).
    - Based on the inputs to the spreadsheet provided by ADEC, EUs 1 thorough 6 are being treated as a single, lumped heat input value. This approach is an oversimplification and will not accurately account for the equipment and utilities that will be necessary to independently operate six boilers. The actual installation will require six separate trains of sorbent processing and transport equipment. Each train contains a day bin, mills, feeders, blowers, coolers, hoppers, piping, instrumentation, controls, electrical wiring and other supporting equipment. This need for separate systems complicates the design, increases overall footprint, and reduces the economy of scale that might be realized with a single larger unit. DU notes that the Retrofit Factor reflects a difficult retrofit in an attempt to account for this additional complexity.
    - DU also notes that adjusting the analysis to reflect the retrofit of one CHPP boiler (operated at full-load for 8,760 hr/yr) results in a cost-effectiveness value of greater than $35,000 per ton of SO_2 removed. That cost-effectiveness value is significantly greater than the $10,329 per ton removed presented in Section 5.1, Table 5-3 of the BACT Determination (Appendix III.D.7.07, pdf page 357 of 2309). BACT analyses are typically prepared for each emissions unit at a facility. While "grouping" emissions units is not necessarily unreasonable, a BACT analysis prepared for a group of emissions units must be proper and realistic. The S&L cost model does not appear to properly capture the emission control costs for EUs 1 through 6 as a group.
    - The sorbent feed rate currently calculated for EUs 1 through 6 is very low. Should the model be revised to calculate the cost effectiveness on a per unit basis, the feed rate would be roughly one sixth of the current value. This change would further amplify concerns about the accuracy of the TPC calculation.

- ADEC assumed that the model is valid for a heat and power plant.
    - As discussed above, no information is available addressing the type of plant on which the S&L spreadsheet is based. The assumption is that the plant is a single power generation unit. A CHP plant differs significantly from a "traditional" power plant in that the steam produced in a CHP plant is not exclusively used to generate electricity. In an effort to make the spreadsheet work for this application, ADEC used "dummy" data in the "Unit Size (Gross)" and "Gross Heat Rate" fields so that the calculated "Heat Input" field showed the maximum heat input value for EUs 1 through 6 (1,380 million British thermal units per hour (MMBtu/hr)). This approach has unintended consequences relating to the accuracy of the direct annual costs. The fixed and variable operating and maintenance (O&M) costs are

evaluated on a per kilowatt and a per megawatt basis respectively. Utilizing a "dummy" gross generation number to calculate annual costs may not produce an accurate result. Based on review, no method exists to accurately model the direct annual costs for an installation such as the DU EUs 1 through 6 by using the S&L spreadsheet.

  - The average maximum hourly heat input identified in Row 15 of the spreadsheet is incorrect. The value shown reflects the maximum hourly heat input for each of the boiler. The value does not account for the permitted annual coal consumption limit. If the coal consumption limit is considered, the maximum hourly heat input is reduced to 583 MMBtu/hr averaged over a year. A reduction in hourly heat input will have an impact on the overall cost effectiveness calculation, but given the concerns with the calculation itself, identifying the specific impacts is difficult.

- SO_2 Emission Rates: The SIP uses two different SO_2 emission rates. The preliminary BACT determination states that the SO_2 emission rate used in the spreadsheet to calculate the total annualized operating costs was based on 0.2 weight percent (wt. pct.) sulfur coal and AP-42 emission factors. This approach resulted in an emission rate of 0.46 pounds of SO_2 per MMBtu (lb SO_2/MMBtu) heat input. This value is significantly different than the effective emission rate for the plant based on the PTE established in Title V Permit AQ1121TVP02, Revision 2. The effective emission rate is calculated as follows:

  Permitted PTE: 1,764 tons of SO_2
  Permitted coal consumption limit: 336,000 tpy
  Assumed coal energy content: 7,600 British thermal units per pound (Btu/lb)

  1,764 tons SO_2/yr * 1 year/336,000 tons coal * 1 lb coal/7,600 Btu * 10^6 Btu/MMBtu * 1 ton coal/2,000 lb coal * 2,000 lb SO_2/ton
  = 0.691 lb SO_2/MMBtu

  The difference between the ADEC-assumed emission rate and the effective emission rate leads to a significant discrepancy in the SO_2 cost effectiveness calculation. The ADEC spreadsheet divides the total annualized cost (determined by using the 0.46 lb/MMBtu SO_2 rate) by the SO_2 PTE (with an effective rate of 0.691 lb/MMBtu). The use of two different emission rates in this calculation results in an invalid comparison of two values that should not be compared to each other. For the result of the equation to be valid, the total annualized cost must be calculated using an SO_2 emission rate equal to the SO_2 PTE.

- Conclusion: Based on the review of the proposed SO_2 BACT determination and the associated cost effectiveness calculation, no indication could be found that the proposed BACT Determination calculation accurately reflects the actual operating conditions for EUs 1 through 6.

If a more accurate cost effectiveness is to be determined, the cost effectiveness should be recalculated using a bottom-up cost estimating approach based on actual plant conditions. These conditions would include SO_2 emission rates based on current PTE, permit constraints (where applicable and enforceable), available space, ambient conditions, and local factors such as construction logistics, labor wage rates, and local sorbent costs.

23. In Section 5.1 of the proposed BACT Determination, the proposed requirement for the coal sulfur content to be no greater than 0.2 weight percent is not evaluated using the five-step BACT process, or even identified as an available control technology in Step 1. (All coal mined at the Usibelli Coal Mine meets the definition of "low sulfur coal," which is coal with a sulfur content of less than one percent sulfur. The low sulfur coal is considered in Step 1(d).) The current coal sulfur content is not limited beyond the State SIP SO_2 standard and the requirement to determine what the SO_2 emission concentrations would be prior to combusting coal with a sulfur content of greater than 0.4 weight percent. (Refer to Conditions 11 and 11.1 of Permit AQ1121TVP02, Revision 2.) Imposing this limit without first preparing a proper BACT analysis is not appropriate. If this requirement is to be imposed as a limit without a proper BACT analysis to justify the limit, then the limit should be used to calculate a revised baseline emission rate. The BACT analysis should then calculate any further emission reductions based on that revised baseline emission rate.

    DU does not agree that the coal sulfur content assumption of less than or equal to 0.2 weight percent is appropriate. More investigation is needed to determine whether this assumption is valid and feasible. The 0.2 weight percent coal sulfur limit should be assessed through the BACT analysis process. Step 1(d) of the proposed BACT Determination acknowledges that the current contract guarantee is less than 0.4 weight percent sulfur, and that the coal typically ranges from 0.08 to 0.28 weight percent sulfur.

    DU does not procure coal used in the DU CHPP, but is expected to support the Department of Defense's preference to maintain a 90 day coal stockpile in the interests of energy security for Fort Wainwright. The existing 90 day coal storage pile at the CHPP includes coal with a variety of sulfur contents because coal is added to and removed from the pile over a period of years. The sulfur content of the coal pile is not certain to be less than 0.2 weight percent throughout the pile. If the final BACT requirements specify a coal sulfur content less than that currently specified contractually between the Army and Usibelli Coal Mine, please provide a limit to require that any future deliveries of coal meet the sulfur content specification as opposed to limiting the sulfur content of all coal being combusted at the DU CHPP. The coal pile at the DU CHPP is primarily an emergency storage pile and use of that stockpiled coal should not be restricted.

    The Serious SIP was silent on how the sulfur content of coal was to be reported or considered within a regulatory context. The standard operating permit condition should remain the same and that facilities continue to have available the sulfur content of each shipment of fuel.

24. Section 5.1 of the proposed SIP document appears to present language for a possible compliance order by consent (COBC) between ADEC and FWA that would impose requirements on the DU CHPP emissions units. The document does not explain how (or whether) a COBC between ADEC and the Army would ultimately apply to DU or the DU-owned emissions units. The language in the proposed COBC does not distinguish between the entire CHPP and EUs 1-6, and addresses the

additional BACT for the large diesel-fired engines or the source testing or the PM2.5 emission limits for EUs 7a, 7b, 7c, 51a, 51b and requires each EU to be source tested to demonstrate compliance

25. Section 7.7.8.3.3 of the proposed SIP document is unclear as to whether the 0.2 weight percent sulfur limit is a BACT limit or proposed as a requirement in the COBC, or both. If the 0.2 weight percent sulfur limit is intended to be a BACT limit, a BACT analysis was not prepared for this control technology. The underlying BACT determination document does not include a BACT limit requiring the use of coal with a sulfur content less than 0.2 weight percent.

26. Section 5.3 in the proposed BACT Determination for large diesel-fired engines, specifically Step 5(d), states that non-emergency operation of EU 8 is limited to "no more than 100 hours per year for maintenance checks and readiness testing." This requirement is inconsistent with Title V Permit AQ1121TVP02, Revision 2 which allows EU 8 to be converted to a non-emergency engine with a limit of 500 hours per year. (Please refer to Conditions 24.3 through 24.6). Please revise this requirement to clarify that the limit applies only while the engine is classified as an emergency engine, and that the limit is not inconsistent with applicable requirements under 40 CFR 60 Subpart IIII, which allows 100 hours per year of non-emergency operation but does not restrict those non-emergency operations to maintenance checks and readiness testing. (Please refer to Condition 23.3c of AQ1121TVP02, Revision 2 and 40 CFR 60.4211(f)(3).) Please align the BACT requirements to be consistent with the existing applicable permit requirements and ensure that Section 7.7.8.3.3 of the proposed SIP document is revised for consistency with the underlying proposed BACT Determination.

27. Section 5.4 in the proposed BACT determination for small diesel-fired engines, specifically Step 5(c), requires maintaining good combustion practices. The determination that good combustion practices is BACT should be eliminated or a rationale should be provided for selecting good combustion practices in addition to the combustion of ULSD and limited operations. Per Table 5-10 in Section 5.4, good combustion practices were not determined to be SO_2 BACT for small diesel-fired engines at another stationary source. While DU follows good combustion practices as a standard practice, Step 3(c) indicates that good combustion practices are the least effective SO_2 emission control technology.

28. Section 5.4 in the proposed BACT Determination for small diesel-fired engines, specifically Step 5(a), states that non-emergency operation of the small emergency engines is limited to "no more than 100 hours per year for maintenance checks and readiness testing." Please revise this requirement to clarify that the limit is not inconsistent with applicable requirements under 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ, which allow 100 hours per year of non-emergency operation but does not restrict those non-emergency operations to maintenance checks and readiness testing. (Please refer to Conditions 23.3c and 30.3 of AQ1121TVP02, Revision 2, 40 CFR 60.4211(f)(3), and 40 CFR 63.6640(f).) Please align the BACT requirements to be consistent with the existing applicable permit requirements and ensure that Section 7.7.8.3.3 of the proposed SIP document is revised for consistency with the underlying proposed BACT Determination.

Attachment 2

DU correspondence dated December 31, 2018 notifying ADEC of a generator asset transfer from DU to the Army at Ft Wainwright

Adopted

November 19, 2019

DOYON UTILITIES LLC

714 Fourth Avenue, Suite 100 • Fairbanks, AK 99701
PO Box 74040 • Fairbanks, AK 99707
Phone (907) 455-1500 • Fax (907) 455-6788

December 31, 2018

Alaska Department of Environmental Conservation
Air Permits Program
410 Willoughby Avenue, Suite 303
PO Box 111800
Juneau, AK 99801-1800

SUBJECT: Notification of Asset Transfers from the Fort Wainwright (Privatized Emission Units) to the U.S. Army Garrison Fort Wainwright

Doyon Utilities, LLC (DU) is submitting this letter to notify the Alaska Department of Environmental Conservation (ADEC) about the ownership transfer of emissions units previously held by DU to the U.S. Army Garrison Fort Wainwright (Army-FWA).

DU holds Permit No. AQ1121TVP02, Revision 2, for the Fort Wainwright (Privatized Emission Units) portion of the stationary source (DU-FWA). This Permit covers infrastructure, including emissions units, which is owned and operated by DU. Emissions units covered by DU's permits include 16 units identified on Table 1, which accompanies this letter. On December 28, 2018, ownership of these emission units was transferred from DU to the U.S. Army Garrison Fort Wainwright (Army-FWA) through a Bill of Sale and related easement executed between DU and the U.S. Army Corps of Engineers. As of December 29, 2018, the emission units listed in Table 1 are no longer under the ownership or control of DU.

The emission units, listed in Table 1, are now under the ownership of Army-FWA. The Army-FWA currently holds Permit No. AQ0236TVP03, Revision 2. As agreed in a meeting on April 20, 2017 with ADEC and Army-FWA, until DU's Permit No. AQ1121TVP02 is renewed, DU compliance reports will itemize the transferred emissions units, but will reflect that the units have been transferred to the Army-FWA under its Permit. The Army will be responsible for compliance of and reporting for these units under its Permit. It should be noted that Army-FWA submitted a permit revision application to accept ownership and control of these emission units on November 27, 2017. Accordingly, ADEC should contact Army-FWA with questions or concerns about these units.

Sincerely,

Ed Stevenson

Ed Stevenson
VP of Operations

cc: Patrick Dunn, ADEC – Anchorage
Eric Dick, DPW – Fort Wainwright
Kathleen Hook, DU- Fairbanks
Shayne Coiley, DU- Fairbanks
Courtney Kimball, SLR – Fairbanks

CO 18-125

Table 1. Emission Units Transferred from DU Ownership to the U.S. Army Garrison Fort Wainwright

AQ1121TVP02 Rev. 2 EU ID	EU Name	EU Description	Rating/Size	Installation Date
10	Emergency Generator Engine	Building 1060	762 hp	2010
11	Emergency Generator Engine	Building 1060	762 hp	2010
12	Emergency Generator Engine	Building 1193	82 hp	2002
13	Emergency Generator Engine	Building 1555	587 hp	2008
15	Emergency Generator Engine	Building 2117	1,059 hp	2005
16	Emergency Generator Engine	Building 2117	212 hp	2005
17	Emergency Generator Engine	Building 2088	176 hp	2007
18	Emergency Generator Engine	Building 2296	212 hp	2005
19	Emergency Generator Engine	Building 3004	71 hp	2007
20	Emergency Generator Engine	Building 3028	35 hp	1976
21	Emergency Generator Engine	Building 3407	95 hp	2001
24	Emergency Generator Engine	Building 3703	50 hp	1993
25	Emergency Generator Engine	Building 5108	18 hp	2011
26	Emergency Generator Engine	Building 1620	68 hp	2003
27	Emergency Generator Engine	Building 1054	274 hp	2010
28	Emergency Generator Engine	Building 4390	274 hp	2010

From:	INGOGLIA, J M GS-14 USAF AFMC PACAF/AFIMSC Det 2/CEV
To:	Dec Air Comment; Heil, Cynthia L (DEC)
Cc:	HOLLIDAY, MICHAL D Col USAF PACAF/AFIMSC Det 2/CE; STRINGHAM, KATHERINE L GS-13 USAF PACAF/PACAF/AFIMSC Det 2/CEV; WEBB, SCOTT GS-13 USAF AFCEC AFCEE/CZOP; MARTINSON, DAVID A GS-14 USAF PACAF 354 CES/CD
Subject:	Formal Comment to Proposed Regulation Changes Relating to Fine Particulate Matter (PM2.5); Including New and Revised Air Quality Controls and State Implementation Plan (SIP)
Date:	Friday, July 26, 2019 4:28:00 PM
Attachments:	USAF SIP Comments.pdf

Ms Heil,

Attached are USAF comments on the proposed regulation.

We appreciate the opportunity to comment.

Sincerely,

J. Mark Ingoglia, DAF GS14
Chief, Environmental Branch
AFIMSC Det 2, CEV
808 449-1077

DEPARTMENT OF THE AIR FORCE
DETACHMENT 2, AIR FORCE INSTALLATION AND MISSION SUPPORT CENTER
JOINT BASE PEARL HARBOR-HICKAM, HAWAII

26 July 2019

MEMORANDUM FOR ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION
ATTN: CINDY HEIL
Division of Air Quality
555 Cordova Street
Anchorage AK 99501

FROM: AFIMSC Det 2/CE
25 E. St, Suite C-310, Bldg 1102
JBPH-H, HI 96853-5412

SUBJECT: Formal Comment to Proposed Regulation Changes Relating to Fine Particulate Matter (PM2.5); Including New and Revised Air Quality Controls and State Implementation Plan (SIP)

1. On 14 May 2019, the Alaska Department of Environmental Conservation (ADEC) released the Serious Area State Implementation Plan (SIP) for the Fairbanks North Star Borough (FNSB) Fine Particulate (PM2.5) Nonattainment Area (NAA) for public review. Public comments are due by 5:00 p.m. on 26 July 2019. The Air Force appreciates the opportunity to comment on the SIP and the collaborative effort with the ADEC to provide a means to attain the PM2.5 24-hour standard.

2. Although Eielson Air Force Base in not within the NAA, Eielson shares a coal contract with Fort Wainwright Army Garrison for coal obtained from Usibelli Coal Mine (UCM). The Air Force has the following comment on the sulfur content of coal.

a. In Amendments to State Air Quality Control Plan Vol. III: Appendix III.D.7.07 and in the Best Available Control Technology (BACT) Summary Highlight located at http://dec.alaska.gov/media/16232/bact-summary-highlight-051419.pdf, the proposed BACT for coal-sulfur content is 0.2 percent sulfur by weight. This sulfur limit will cut off access to tens of millions of tons of coal from UCM as well as pose a potential threat of fuel supply interruption for the coal-fired power plants using UCM coal.

b. The Air Force requests ADEC adopt a BACT coal-sulfur content of 0.25 percent sulfur by weight based on a semi-annual weighted average of coal-sulfur content in shipments of coal within the semi-annual period corresponding to Facility Operating Report reporting period.

c. The ADEC has proposed that BACT for coal burning facilities in the nonattainment area is a coal-sulfur limit of 0.2 percent sulfur by weight. UCM is the only source of commercial coal available to the coal-fired boiler facilities within the Fairbanks North Star Borough fine particulate nonattainment area. The mine has limited ability to affect the sulfur content in the coal. There is not a coal washing or segregating facility associated with UCM which could ensure a consistent coal-sulfur concentration. Current practice for providing low-sulfur coal to their customers is identifying sulfur content of the resource through drilling and sampling efforts. However, the ability to characterize the sulfur content of the coal mined is limited.

Within the millions of tons of coal resources available to UCM, there is a significant amount of coal with higher sulfur content than 0.2 percent by weight; in fact, any limit proposed to the coal sulfur content is effectively cutting off access to tens of millions of tons of coal resources. As such, the Air Force proposes that the coal-sulfur content limit be lowered to 0.25 percent by weight on an as received basis (wet) as opposed to 0.2 percent by weight as proposed by ADEC. The increase in coal sulfur content will help with coal accessibility and availability over the next decade.

The state was silent on how the measure was to be reported or considered within a regulatory context. The ADEC's standard permit condition for coal fired boilers (Standard Condition XIII) requires that the permittee report sulfur content of each shipment of fuel with the semi-annual Facility Operating Reports. UCM currently provides a semi-annual report to all customers which includes sulfur content of each shipment of coal along with the weighted average coal-sulfur content for the six-month period coinciding with the operating reports' reporting period. The Air Force proposes that the standard operating permit condition remain the same, and that facilities continue to provide the state with the sulfur content of each shipment of fuel; in addition, the weighted average coal-sulfur content of the shipments received by the facility during the reporting period would be referenced in the operating report.

3. If additional information is required, please contact Katherine Stringham, Regional Support Branch Air Program Manager, directly by e-mail at katherine.stringham@us.af.mil or by telephone at (808) 449-1094.

MICHAL HOLLIDAY, Colonel, USAF
Division Chief

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PO Box 74040
Fairbanks, AK 99707

October 4, 2019

Cindy Heil
Alaska Department of Environmental Conservation
Division of Air Quality
555 Cordova St
Anchorage, AK 99501

Re: Additional Comments Addressing the Proposed Best Available Control Technology Determination for Fort Wainwright US Army Garrison and Doyon Utilities

Dear Ms. Heil:

Thank you for the opportunity to provide further information with respect to the proposed Serious SIP. As you know, Doyon Utilities, LLC (DU) provided comments on July 26, 2019 addressing the proposed Best Available Control Technology (BACT) assessment that the Alaska Department of Environmental Conservation (ADEC) prepared, in relevant part, for DU's Central Heat and Power Plant (CHPP) located on Fort Wainwright.

By way of brief background, DU's previous comments noted that the Serious SIP estimated $14.5 million for BACT technology to be installed on all six of DU's boilers. DU identified that this estimate was based on unsupported assumptions and use of a cost model that may not be appropriate for the size of the boilers. DU further noted it had retained engineers from Black and Veatch (B&V) to prepare a high-level estimate, including the costs of DU's contract-required project deliverables, resulting in an installed DSI estimated cost range of approximately double the Serious SIP estimate.

On September 24, 2019, ADEC requested the underlying information provided by B&V. DU hereby submits the memorandum prepared by B&V in July 2019 and reflecting cost estimates for the installation of dry sorbent injection (DSI) on the CHPP boilers. This document reflects B&V assumptions which include coal sulfur content at 0.25%, building enclosure for all pieces of equipment including the silos due to the cold temperatures in Fairbanks, and sorbent delivery costs to Alaska.

B&V provided cost estimates for two types of DSI, Trona and Sodium Bicarbonate (SBC). DU's CHPP operates at approximately 260° Fahrenheit stack temperature. Trona would be effective at this lower stack temperature. Sodium bicarbonate requires a stack temperature above 275° Fahrenheit in order to have a significant impact on SO2 reduction, and would require additional equipment to increase the flue gas temperature. For purposes of determining economic feasibility, DU believes the Trona DSI is the more feasible, least expensive, and likely installation.

In the normal course of utility accounting and project development, DU prepares a project cost estimate worksheet which summarizes both the engineered procured constructed costs, but also includes contract-required DU project management, environmental permitting support, quality assurance reviews, and project deliverables such as GIS, project schematics and documentation. DU followed its standard project estimating procedures, and prepared the enclosed worksheet as used for every utility project in the normal course of our business. This project worksheet reflects DU's cost breakdowns for the standard deliverables required on all capital work by our customer prior to the time a project is considered complete.

In addition to the project costs, there is a dollar value reflecting an Allowance for Funds Used During Construction (AFUDC). Utilities like DU include AFUDC in project costs as a mechanism to recover the costs of advancing funds during the construction phase.

The following is the total estimate for installing Trona DSI on DU's boilers on Fort Wainwright:

Trona DSI System (Engineered Procured Constructed)		$21,681,150
AFUDC		$3,805,335
	Total	**$25,486,485**

In addition to the project costs, B&V estimates annual operating costs of **$2,741,500.**

DU is concerned that this Rough Order of Magnitude (ROM) estimate is still low. For example, this ROM assumes zero dollars for landfill disposal costs. The addition of DSI will increase the CHPP coal ash waste stream and have long term impact to the FWA landfill. The FWA landfill is currently closed and does not accept waste except for CHPP coal ash. DU is operating on Wainwright disposal approval through 2023. DSI operations will increase the coal ash waste generated, therefore DU anticipates that it is likely a new offsite landfill location would be required sooner than anticipated, which would require both significant initial capital costs and ongoing operation costs. In addition, construction on FWA routinely requires management of contaminated soils. However, because this is a ROM estimate, and there has been no preliminary site survey, no costs have been included to manage and dispose of a fairly large excavation, although DU would anticipate encountering soils and groundwater that are contaminated with solvents and petroleum products.

DU understands ADEC's commitment to the SIP process and recognizes and supports the Army's efforts to evaluate the future options for reduced emissions. DU is willing and able to work with ADEC to address any questions or issues that our comments may raise. Please contact Kathleen Hook at khook@doyonutilities.com if you have any questions or would like to further discuss any specific comments.

Best Regards,

Shayne Coiley
Senior Vice President
Doyon Utilities, LLC

cc: S. Koessel, DLA Energy
S. Kimble, DLA Energy
S. Stringham, Utility Chief, FWA Garrison
F. Sandgren, COR, FWA Garrison
D. Burgess, COR, FWA Garrison
P. Marvin,COR FWA Garrison
D.Jones, ADEC

Encl.
B&V Project Estimate
DU Project Cost Estimate
CO 19-084

Adopted
[redacted]

November 19, 2019
[redacted]

MEMORANDUM

Doyon Utilities, LLC, Fairbanks, Alaska
710 4th Ave. Suite 100
Fairbanks, Alaska 99707

[redacted]
July 22, 2019

Attention: [redacted]

Subject: DSI FWA CHPP Cost Estimate Development [redacted]
Cost Estimate for DSI System at Fort Wainwright

Introduction:

[redacted] is pleased to provide this dry sorbent injection (DSI) cost estimate to Doyon Utilities. The cost estimate has been developed by an experienced Air Quality Control specialist that understands the requirements and operating factors to support an installation of this type for the Fort Wainwright (FWA) Garrison. The estimate is for equipment that will support continued operation of the [redacted] boilers at the current FWA combined heat and power plant (CHPP) facility. [redacted] has an experienced air quality staff that can assist with meeting permitting needs, permit requirements, and advise on equipment to meet air emissions at utility power plants, industrial plants, and combined heat and power facilities.

As you are aware, [redacted] The [redacted] team gave several presentations to Doyon Utilities and the US Army, [redacted] regarding estimated costs and recommendations for future planning. The future planning [redacted], including a DSI system as well as review of other energy technologies [redacted] has a history of providing master planning reports for various assignments, such as campus style environments, military installations, and utility owned combined heat and power (CHP) plants, distributed generation, and microgrid projects.

[redacted] has the experience performing engineering services on projects in Alaska for electric utilities and the US military, as well as for electric utilities and industrial power projects in Canada, the lower 48 states, and internationally.

[redacted] is an accomplished engineering design firm with power design being one of our core areas of business. We have completed several projects, proposals, studies, and estimates regarding the use of DSI for control of SO_2 and SO_3. [redacted] provided support for multiple projects for Golden Valley Electric Association, including engineering design, procurement, and construction assistance to a project located in Healy, Alaska for installing a lime storage and transport feed system. Similar projects that [redacted] has recently been involved with include: studying potential risks associated with implementing DSI technology for primary SO_2 control at the Entergy White Bluff Power Station in Arkansas; balance of plant engineering design, start-up and commissioning of DSI injection system on multiple DTE Energy coal fired power plants in Michigan; design engineering, procurement, and construction management at the Vectren F.B. Culley Station in Indiana using DSI for reduction of SO_3; front end engineering design (FEED) study for installing a DSI system at a 400 MW power plant in Alberta, Canada for reducing SO_2; and DSI systems for two confidential clients.

Cost Estimate:

Doyon Utilities has requested a rough-order-of-magnitude cost estimate for a dry sorbent injection (DSI) system to be installed [redacted] on the Fort Wainwright CHPP for the Garrison in Fairbanks, Alaska. DSI systems have proven effective in removing acid gases from flue gas streams when the required removal efficiencies are lower than 90 percent. At large coal-fired power plants, DSI systems have primarily been used to remove either HCl or SO_3, but SO_2 removal has also been successfully demonstrated on smaller industrial sized power boilers.

[redacted] There are three sorbents that are typically used in DSI systems: hydrated lime, sodium bicarbonate (SBC), and sodium sesquicarbonate dihydrate (commonly known as trona). However, hydrated lime is not known to be effective for removing SO_2, as excessive amounts are required when compared to SBC or trona. This cost estimate therefore evaluated costs using trona and SBC.

The following assumptions were made in developing this rough-order-of-magnitude cost.

- Coal sulfur content of 0.25%.
- Outlet SO_2 emissions of 0.08 lb./MMBtu. [redacted]
- Based on a high level estimate, up to approximately 1,500 ton/yr. of SO_2 could potentially be removed based on a 0.25% sulfur content in the coal. [redacted] (A full combustion calculation would need to be performed with a complete design coal analysis to determine an accurate SO_2 reduction in emissions.)
- The DSI system was sized for [redacted] operating at full capacity.
- A capacity factor [redacted] was applied to the maximum sorbent injection rate [redacted] This factor is used in a high level estimate of annual costs.
- Mills were included to reduce the injection rate of sorbent and therefore the total amount used.
- Building enclosures were provided for all pieces of equipment, [redacted] due to the cold temperatures in Fairbanks, Alaska.
- Performance curves from a vendor [redacted] were used in developing this analysis.
- Sorbent costs for delivery to the FWA CHPP were not provided in time for this deliverable, so a previous project cost was used with a markup [redacted] for delivery to Fairbanks, Alaska.

- Capital costs were rounded to the nearest 100k due to the high-level nature of this estimate.
- Owners Costs are not included.
- Fly ash is not sold from this plant.
- Disposal and landfill costs are currently calculated [redacted] using an on-site landfill area; however, [redacted] if the on-site landfill is closed, an estimated cost [redacted] per ton should be expected in the future.
- Equipment location is considered preliminary [redacted]
- Relocating and/or widening of the ash haul truck roadway [redacted] is anticipated and estimated costs included.
- The injection location temperature was identified to be as low as 260° F and with an average of 275° F. The minimum recommended flue gas temperature for injecting sodium sorbents is 275° F, so this cost estimate assumes an injection location temperature of 275° F. Increasing amounts of sorbent will be required as the flue gas temperature decreases below 275° F.
- Equipment life expectancy is typically 30 years [redacted].

[redacted] has been involved in numerous DSI studies and projects over the years and has access to many budgetary and project costs. For this cost estimate, a project in a northern, cold climate that also had buildings for their equipment was primarily used, but due to some required adjustments, other projects' costs were also utilized.

Based on a design coal with 0.25% sulfur content, the following are estimated costs for installing and operating a DSI system at Fort Wainwright.

Trona (with 0.25% Sulfur Content)

DSI System Cost (purchased equipment)	[redacted]	[redacted]
Piping and Instrumentation	[redacted]	[redacted]
Construction Cost	[redacted]	[redacted]
Engineering, Procurement, and Office Support	[redacted]	
Subtotal	[redacted]	
Contingency (10%)	[redacted]	
Total EPC Cost (Engineer-Procure-Construct)	[redacted]	

Annual Costs (Operations)		
Operating Labor	[redacted]	[redacted]
Maintenance Labor and Materials	[redacted]	[redacted]
Max. Reagent (sorbent) injection rate, lb./hr.	[redacted]	[redacted]
Reagent (sorbent) Cost [redacted] factor	[redacted]	[redacted]

Disposal Cost	[redacted]	[redacted]
Water Cost	[redacted]	[redacted]
Auxiliary Power [redacted]	[redacted]	[redacted]
Total Annual Cost	[redacted]	

SBC (with 0.25% Sulfur Content)

DSI System Cost (purchased equipment)	[redacted]	[redacted]
Piping and Instrumentation	[redacted]	[redacted]
Construction Cost	[redacted]	[redacted]
Engineering, Procurement, and Office Support	[redacted]	
Subtotal	[redacted]	
Contingency (10%)	[redacted]	
Total EPC Cost (Engineer-Procure-Construct)	[redacted]	

Annual Costs (Operations)		
Operating Labor	[redacted]	[redacted]
Maintenance Labor and Materials	[redacted]	[redacted]
Max. Reagent (sorbent) injection rate, lb./hr.	[redacted]	[redacted]
Reagent (sorbent) Cost [redacted] capacity factor	[redacted]	[redacted]
Disposal Cost	[redacted]	[redacted]
Water Cost	[redacted]	[redacted]
Auxiliary Power [redacted] capacity factor	[redacted]	[redacted]
Total Annual Cost	[redacted]	

The coal sample analyses provided did not show sulfur contents consistently in the 0.2% and above range. Although there were peaks with excess of 0.2% sulfur content in the coal, a review of the limited coal analysis pages available indicated that on average, the sulfur content appeared to typically be lower. The DSI system will need to be capable of meeting the air emissions when firing coal with design value 0.25% sulfur content [redacted].

The amount of sulfur to be removed is critical to sizing the system, which will have a significant impact on the installation cost as well as operating cost. The sorbent injection rates were calculated using performance curves provided by [redacted] a leading vendor of sodium sorbents. The performance curves provide the normalized stoichiometric ratio (NSR) for sorbents based on the targeted removal efficiency and particulate control device. The NSR is a multiplier to the theoretical injection rate of sorbent required based on chemical formulas. DSI vendors will have their own performance curves that may be slightly different, but for this analysis, [redacted] curves were used instead of canvassing multiple DSI vendors. For more accurate costs, budgetary estimates from vendors and fine-tuning construction costs would be needed, neither of which were attainable for this effort.

[redacted]

July 22, 2019

Should you have any questions please let me know. If needed, we can set up a call with our air quality control engineer [redacted] that performed this analysis and estimate. It has been a pleasure working with Doyon Utilities on this project and we look forward to assisting you in the future.

Very truly yours,

[redacted]

cc: [redacted] Dovon Utilities, Fairbanks, AK
[redacted]

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Adopted November 19, 2019

DOYON UTILITIES LLC

Project Cost Estimate
Summary Page

DU Job #

Project Name: **DSI System at FWA CHPP - Trona (with 0.25% Sulfur Content)** WTD **n/a**

DU Project #: **TBD** Government RFP #: **n/a** WWC **n/a**

Division: **FWA** DU Project Manager: **TBD** EDS **n/a**

Fund Source: [x] **Rate Base (AFUDC)** [ ] Lump Sum CIAC (IDC) [ ] Expense (no AFUDC or IDC) DHS **TBD**

Description		% of Total Project Costs	$ Amount	Contingency %	Contingency $ Amount
Project Management		2.5%	$626,080		
Environmental		1.0%	$249,340		
Design					
Construction Administration					
Other Professional Services					
Quality Assurance (QA)		0.3%	$89,050		
Geographic Information Systems (GIS)		0.1%	$13,680		
Commissioning					
Subtotal, Non-Construction Costs:		**3.8%**	$978,150		
Construction Contract	*% of Direct Costs*				
Water Utility, Direct Costs					
Wastewater Utility, Direct Costs					
Electric Utility, Direct Costs					
District Heat Utility, Direct Costs:	*100.0%*		$20,100,000		
Subtotal, Direct Utility Costs	*100%*		$20,100,000		
General Conditions, Direct Costs					
Subtotal, Direct Costs (DC):			$20,100,000		
Contractor's Overhead (OH)			*(included above)*		
Contractor's Profit (P)			*(included above)*		
Performance/Payment Bonds 3%	of (DC+OH+P)		$603,000		
Subtotal, Contracted Construction Costs:		81.2%	$20,703,000		
DU-Furnished Construction Materials					
DU-Furnished Construction Labor					
Other Construction					
Subtotal, Construction Costs:		81.2%	$20,703,000		
Subtotal, Non-Construction + Construction:		**85.1%**	**$21,681,150**		
Contingency					
Subtotal, Potential Project Cost Excluding AFUDC or IDC:			*$21,681,150*	*This amount used to estimate AFUDC or IDC*	
AFUDC or IDC			$3,805,335		
Total Project Cost Estimate		**100%**	**$25,486,485**		

Summary, Total Project Costs Pro-rated per Utility at Direct Construction Cost %			*% of Direct Utility Costs*	$ Amount
Water Treatment & Distribution System Utility	WTD	n/a		
Wastewater Collection System Utility	WWC	n/a		
Electric Distribution System Utility	EDS	n/a		
District Heat System Utility	DHS	TBD	*100.0%*	$25,486,485
			100%	$25,486,485

Prepared by: **Hannah Witherington** Date: **10/3/2019** Level of Design for this cost estimate: **10%**

Revision Date: 3/15/2019

DOYON UTILITIES

Project Management and Environmetal Services

Project Name:	**DSI System at FWA CHPP - Trona (with 0.25% Sulfur Content)**		DU Job #
		WTD	**n/a**
DU Project #:	**TBD**	WWC	**n/a**
Division:	**FWA**	EDS	**n/a**
Gov't. RFP #:	**n/a**	DHS	**TBD**

Project Management

DU Personnel **Description**	**Avg. Hours per Week**	**Estimated # of Weeks**	**Estimated Total Hrs.**	**Burdened Hourly Rate**	**Amount**
DU Project Manager	20	182	3,640	172	626,080
				Subtotal:	626,080
Contract PM Services and Other PM Costs (travel, per diem, etc.) **Description**					**Amount**
				Subtotal:	
				Project Subtotal, Project Management:	**626,080**

Environmental

DU Personnel **Description**	**Avg. Hours per Week**	**Estimated # of Weeks**	**Estimated Total Hrs.**	**Burdened Hourly Rate**	**Amount**
DU Environmental Specialist	10	182	1,820	137	249,340
				Subtotal:	249,340
Contract Environmental Services and Other Environmental Costs **Description**					**Amount**
Hazardous Materials Survey					
Asbestos Survey					
Lead Survey					
Contaminated Soils Investigation					
Contaminated Soils Monitoring					
				Subtotal:	
				Project Subtotal, Environmental:	**249,340**

DOYON UTILITIES LLC

Quality Assurance (QA)
Geographic Information Systems (GIS)
Commissioning

			DU Job #
Project Name:	**DSI System at FWA CHPP - Trona (with 0.25% Sulfur Content)**	WTD	**n/a**
DU Project #:	**TBD**	WWC	**n/a**
Division:	**FWA**	EDS	**n/a**
Gov't. RFP #:	**n/a**	DHS	**TBD**

Quality Assurance (QA)

DU Personnel Description	Avg. Hours per Week	Estimated # of Weeks	Estimated Total Hrs.	Burdened Hourly Rate	Amount
DU QA Specialist	10	65	650	137	89,050
				Subtotal:	89,050

Contract QA Services and Other QA Costs Description	Amount
Subtotal:	
Project Subtotal, Quality Assurance (QA):	**89,050**

Geographic Information Systems (GIS)

DU Personnel Description	Avg. Hours per Week	Estimated # of Weeks	Estimated Total Hrs.	Burdened Hourly Rate	Amount
DU GIS Analyst	8	15	120	114	13,680
				Subtotal:	13,680

Contract GIS Services and Other GIS Costs Description	Amount
Subtotal:	
Project Subtotal, GIS:	**13,680**

Commissioning

Contract Commissioning Services and Other Commissioning Costs Description	Amount
Project Subtotal, Commisioning:	

DOYON UTILITIES LLC

Heat Distribution System Utility, Direct Costs

Project Name: **DSI System at FWA CHPP - Trona (with 0.25% Sulfur Content)**

DU Project #: **TBD** Division: **FWA** Gov't. RFP #: **n/a**

DHS Job #: **n/a**

	Description	QTY	Unit	Materials Cost		Labor Cost		Equipment Cost		Subtotal Cost
				$ / Unit	Extended	$ / Unit	Extended	$ / Unit	Extended	
1	DSI System Cost (purchased equipment)	1	LS	5,700,000.00	5,700,000					5,700,000
2	Piping and Instrumentation	1	LS	1,700,000.00	1,700,000					1,700,000
3	Construction Cost	1	LS			7,500,000.00	7,500,000			7,500,000
4	Engineering, Procurement, and Office Support	1	LS			3,500,000.00	3,500,000			3,500,000
5	Contingency (10%)	1	LS	1,700,000.00	1,700,000					1,700,000
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28										
29	**Project Subtotal, Heat Distribution System Utility, Direct Costs:**									**20,100,000**

DOYON UTILITIES LLC

Estimate of Cash Flow and Allowance for Funds Used During Construction (AFUDC) Charges (2018 Rate**)

AFUDC charges are incurred only if the Total Project Cost exceeds $150,00 and the project lasts longer than 6 months.

Project Name: **DSI System at FWA CHPP - Trona (with 0.25% Sulfur Content)**
DU Project #: **TBD** Division: **FWA** Gov't. RFP #: **n/a**
DU Job #(s): WTD **n/a** WWC **n/a** EDS **n/a** DHS **TBD**

Step 1 **Enter actual and/or estimated monthly cash flow from start to end of project**
Step 2 **Enter "X" at month of Substantial Completion**

Substantial Completion is achieved when the project is "used and useful". Punch List items may be incomplete.

AFUDC charges stop accumulating at Substantial Completion.

Project Cost Estimate (*not including AFUDC*):	**$21,681,150**
*Estimated cumulative Project Spending:	**$21,681,150**
**Total Estimated AFUDC Charges:	**$3,805,335**

These 2 amounts should be equal when this form is complete.

Project Year 1	2019 (Calendar Year)													
	January	February	March	April	May	June	July	August	September	October	November	December	Total for Yr.	Cummulative to Date
*Estimated Monthly Project Spending:	$2,750,000	$2,640,000	$2,640,000	$350,000	$350,000	$350,000	$350,000	$350,000	$350,000	$350,000	$350,000	$350,000	**$11,180,000**	
*Est. cumulative Project Spending:	$2,750,000	$5,390,000	$8,030,000	$8,380,000	$8,730,000	$9,080,000	$9,430,000	$9,780,000	$10,130,000	$10,480,000	$10,830,000	$11,180,000		**$11,180,000**
Enter "X" at month of Substantial Completion:														
**Estimated Monthly AFUDC charge:	**$17,373**	**$34,052**	**$50,730**	**$52,941**	**$55,152**	**$57,364**	**$59,575**	**$61,786**	**$63,997**	**$66,208**	**$68,419**	**$70,630**	**$658,227**	**$658,227**

Project Year 2	2020													
	January	February	March	April	May	June	July	August	September	October	November	December	Total for Yr.	Cummulative to Date
*Estimated Monthly Project Spending:	$350,000	$350,000	$350,000	$350,000	$350,000	$350,000	$350,000	$350,000	$350,000	$350,000	$350,000	$350,000	**$4,200,000**	
*Est. cumulative Project Spending:	$11,530,000	$11,880,000	$12,230,000	$12,580,000	$12,930,000	$13,280,000	$13,630,000	$13,980,000	$14,330,000	$14,680,000	$15,030,000	$15,380,000		**$15,380,000**
Enter "X" at month of Substantial Completion:														
**Estimated Monthly AFUDC charge:	**$72,842**	**$75,053**	**$77,264**	**$79,475**	**$81,686**	**$83,897**	**$86,109**	**$88,320**	**$90,531**	**$92,742**	**$94,953**	**$97,164**	**$1,020,036**	**$1,678,263**

Project Year 3	2021													
	January	February	March	April	May	June	July	August	September	October	November	December	Total for Yr.	Cummulative to Date
*Estimated Monthly Project Spending:	$350,000	$350,000	$350,000	$350,000	$350,000	$350,000	$350,000	$350,000	$350,000	$350,000	$350,000	$350,000	**$4,200,000**	
*Est. cumulative Project Spending:	$15,730,000	$16,080,000	$16,430,000	$16,780,000	$17,130,000	$17,480,000	$17,830,000	$18,180,000	$18,530,000	$18,880,000	$19,230,000	$19,580,000		**$19,580,000**
Enter "X" at month of Substantial Completion:														
**Estimated Monthly AFUDC charge:	**$99,375**	**$101,587**	**$103,798**	**$106,009**	**$108,220**	**$110,431**	**$112,642**	**$114,854**	**$117,065**	**$119,276**	**$121,487**	**$123,698**	**$1,338,442**	**$3,016,705**

Project Year 4	2022													
	January	February	March	April	May	June	July	August	September	October	November	December	Total for Yr.	Cummulative to Date
*Estimated Monthly Project Spending:	$350,000	$350,000	$350,000	$350,000	$350,000	$351,150							**$2,101,150**	
*Est. cumulative Project Spending:	$19,930,000	$20,280,000	$20,630,000	$20,980,000	$21,330,000	$21,681,150	$21,681,150	$21,681,150	$21,681,150	$21,681,150	$21,681,150	$21,681,150		**$21,681,150**
Enter "X" at month of Substantial Completion:						**x**								
**Estimated Monthly AFUDC charge:	**$125,909**	**$128,120**	**$130,332**	**$132,543**	**$134,754**	**$136,972**							**$788,630**	**$3,805,335**

Project Year 5	2023													
	January	February	March	April	May	June	July	August	September	October	November	December	Total for Yr.	Cummulative to Date
*Estimated Monthly Project Spending:														
*Est. cumulative Project Spending:	$21,681,150	$21,681,150	$21,681,150	$21,681,150	$21,681,150	$21,681,150	$21,681,150	$21,681,150	$21,681,150	$21,681,150	$21,681,150	$21,681,150		**$21,681,150**
Enter "X" at month of Substantial Completion:														
**Estimated Monthly AFUDC charge:														

* *Not including AFUDC*
***AFUDC calculation formula updated 2/18/2016*

ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION
Air Permits Program

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

Prepared by: Aaron Simpson
Supervisor: James R. Plosay
Final Date: November 13, 2019

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Table of Contents

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 within the military installation at Fort Wainwright 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]

This report addresses the significant EUs listed in the DU permit AQ1121TVP02, Revision 2 and the FWA permit AQ0236TVP03, Revision 2. This report provides the Department's review of the BACT analysis for PM-2.5 and BACT analyses provided for oxides of nitrogen (NOx) and sulfur dioxide (SO_2) emissions, which are precursor pollutants that can form PM-2.5 in the atmosphere post combustion.

The 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 NOx, 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.

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

Table A: 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
29	Emergency Pump Engine	75 hp	Building 1056
30	Emergency Pump Engine	75 hp	Building 3403
31	Emergency Pump Engine	75 hp	Building 3724
32	Emergency Pump Engine	75 hp	Building 4162
33	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
51a	DC-1 Fly Ash Dust Collector	3,620 acfm	CHPP
51b	DC-2 Bottom Ash Dust Collector	3,620 acfm	CHPP
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 kW	Building 3498
38	Fire Pump #1	120 hp	Building 5009
39	Fire Pump #2	120 hp	Building 5009
40	Waste Oil-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
60	Emergency Generator Engine	95 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
???	Distillate Fired Boilers (23)	Varies	Varies
???	Waste Oil-Fired Boiler	2.5 gal/hr	Building 3476
???	Waste Oil-Fired Boiler	2.5 gal/hr	Building 3476

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

Step 1 Identify All Potentially Available Control Technologies
The Department identifies all available control technologies for the 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 NOx, PM-2.5, and SO_2 emissions from equipment similar to those listed in Table A and Table B.

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 3, 4, and 5, present the Department's BACT determinations for NOx, PM-2.5, and SO_2.

Step 5 Select BACT
The Department selects the most effective control option not eliminated in Step 4 as BACT for the pollutant and EU under review and lists the final BACT requirements determined for each EU in this step. A project may achieve emission reductions through the application of available technologies, changes in process design, and/or operational limitations. The Department reviewed Fort Wainwright's BACT analysis and made BACT determinations for NOx, 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

The NOx controls proposed in this section are not planned to be implemented. The optional precursor demonstration (as allowed under 40 C.F.R. 51.1006) for the precursor gas NOx for point sources illustrates that NOx controls are not needed. DEC is planning to submit with the Serious SIP a final precursor demonstration as justification not to require NOx controls. Please see the precursor demonstration for NOx in the Serious SIP Modeling Chapter III.D.7.8. The PM2.5 NAAQS Final SIP Requirements Rule states if the state determines through a precursor demonstration that controls for a precursor gas are not needed for attaining the standard, then the controls identified as BACT/BACM or Most Stringent Measure for the precursor gas are not required to be implemented.[2] Final approval of the precursor demonstration is at the time of the Serious SIP approval.

Fort Wainwright has six existing 230 million British Thermal Units (MMBtu)/hr spreader-stoker type boilers that burn coal to produce steam for stationary source-wide heating and power. It also contains small and large emergency engines, fire pumps, and generators, diesel-fired boilers, and material handling equipment subject to BACT. The Department reviewed the control technologies Fort Wainwright identified in their analysis and made a NOx BACT finding for the EUs listed in Tables A and B.

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

3.1 NOx BACT for the Industrial Coal-Fired Boilers

Possible NOx 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 3-1.

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

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

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

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Good Combustion Practices	2	0.1 – 0.6

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

Step 1- Identification of NOx Control Technologies for the Industrial Coal-Fired Boilers
From research, the Department identified the following technologies as available for control of NOx emissions from industrial coal-fired boilers:

(a) Selective Catalytic Reduction (SCR)[3]
SCR is a post-combustion gas treatment technique for reducing nitric oxide (NO) and nitrogen dioxide (NO_2) in the boiler exhaust stream to molecular nitrogen (N_2), water, and oxygen (O_2). In the SCR process, aqueous or anhydrous ammonia (NH_3) is injected into the flue gas upstream of a catalyst bed. The catalyst lowers the activation energy of the NOx decomposition reaction. NOx and NH_3 combine at the catalyst surface forming an ammonium salt intermediate, which subsequently decomposes to produce elemental N_2 and water. Theoretically, SCR systems can be designed for NOx removal efficiencies up close to 100 percent. In practice, commercial coal-, oil-, and natural gas–fired SCR systems are often designed to meet control targets of over 90 percent. However, the reduction may be less than 90 percent when SCR follows other NOx controls such as low NOx burners or flue gas recirculation that achieve relatively low emissions on their own. Challenges associated with using SCR on industrial boilers include a narrow window of acceptable inlet and exhaust temperatures (500°F to 800°F), emission of NH_3 into the atmosphere (NH_3 slip) caused by non-stoichiometric reduction reaction, and disposal of depleted catalysts. The Department considers SCR a technically feasible control technology for the industrial coal-fired boilers.

(b) Selective Non-Catalytic Reduction (SNCR)[4]
SNCR involves the non-catalytic decomposition of NOx in the flue gas to N_2 and water using reducing agents such as urea or NH_3. The process utilizes a gas phase homogeneous reaction between NOx and the reducing agent within a specific temperature window. The reducing agent must be injected into the flue gas at a location in the unit that provides the optimum reaction temperature and residence time. The NH_3 process (trade name-Thermal DeNOx) requires a reaction temperature window of 1,600°F to 2,200°F. In the urea process (trade name–NO_xOUT), the optimum temperature ranges between 1,600°F and 2,100°F. Expected NOx removal efficiencies are typically between 40 to 62 percent, according to the RBLC, or between 30 and 50 percent reduction, according to the EPA fact sheet (EPA-452/F-03-031). The Department considers SNCR a technically feasible control technology for the industrial coal-fired boilers.

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

(c) Non-Selective Catalytic Reduction (NSCR)
NSCR simultaneously reduces NOx and oxidizes CO and hydrocarbons in the exhaust gas to N_2, carbon dioxide (CO_2), and water. The catalyst, usually a noble metal, causes the reducing gases in the exhaust stream (hydrogen, methane, and CO) to reduce both NO and NO_2 to N_2 at a temperature between 800°F and 1,200°F, below the expected temperature of the coal-fired boiler flue gas. NSCR requires a low excess O_2 concentration in the exhaust gas stream to be effective because the O_2 must be depleted before the reduction chemistry can proceed. NSCR is only effective with rich-burn gas-fired units that operate at all times with an air/fuel ratio controller at or close to stoichiometric conditions. Coal-fired boilers operate under conditions far more fuel-lean than required to support NSCR. The Department's research did not identify NSCR as a control technology used to control NOx emissions from large coal-fired boilers installed at any facility after 2005. The Department does not consider NSCR a technically feasible control technology for the industrial coal-fired boilers.

(d) Low NOx Burners (LNBs)
Using LNBs can reduce formation of NOx through careful control of the fuel-air mixture during combustion. Control techniques used in LNBs includes staged air, and staged fuel, as well as other methods that effectively lower the flame temperature. Experience suggests that significant reduction in NOx emissions can be realized using LNBs. The U.S. EPA reports that LNBs have achieved reduction up to 80%, but actual reduction depends on the type of fuel and varies considerably from one installation to another. Typical reductions range from 40% - 60% but under certain conditions, higher reductions are possible. Air staging, or two-stage combustion, is generally described as the introduction of overfire air into the boiler or furnace. Overfire air is the injection of air above the main combustion zone. As indicated by EPA's AP-42, LNBs are applicable to tangential and wall-fired boilers of various sizes but are not applicable to other boiler types such as cyclone furnaces or stokers. The Department does not consider LNBs a technically feasible control technology for the existing stoker type coal-fired boilers.

(e) Circulating Fluidized Bed (CFB)
In a fluidized bed combustor, fuel is introduced to a bed of either sorbent (limestone) or inert material (usually sand) that is fluidized by an upward flow of air. This upward air flow allows for better mixing of the gas and solids to create a better heat transfer and chemical reactions. Combustion takes place in the bed at a lower temperature than other boiler types which lowers the formation of thermally generated NOx. For the purposes of this report, a control technology does not include passive control measures that act to prevent pollutants from forming such as inherent process design features or characteristics. The Department does not consider CFB a technically feasible control technology to retrofit the existing coal-fired boilers.

(f) Low Excess Air (LEA)
Boiler operation with low excess air is considered an integral part of good combustion practices because this process can maximize the boiler efficiency while controlling the formation of NOx. Boilers operated with five to seven percent excess air typically have

peak NOx formation from both peak combustion temperatures and chemical reactions. At both lower and higher excess air concentrations the formation of NOx is reduced. At higher levels of excess air, an increase in the formation of CO occurs. CO can increase exponentially at very high levels of excess air and the combustion efficiency is greatly reduced. As a result, the preference is to reduce excess air such that both NOx and CO generation is minimized and the boiler efficiency is optimized. Only one RLBC entry identified low excess air technology as a NOx control alternative for a mass-feed stoker designed boiler. Boilers are regularly designed to operate with low excess air as described in the previous LNB discussion. The Department considers LEA a technically feasible control technology for the industrial coal-fired boilers.

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

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

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

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

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

(j) Reburn
Reburn is a combustion hardware modification in which the NOx produced in the main combustion zone is reduced in a second combustion zone downstream. This technique involves withholding up to 40 percent (at full load) of the heat input to the main

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

Step 2 - Eliminate Technically Infeasible NOx Control Technologies for the Coal-Fired Boilers
As explained in Step 1 of Section 3.1, the Department does not consider non-selective catalytic reduction, low NOx burners, circulating fluidized beds, fuel switching, steam/water injection, or reburn as technically feasible technologies to control NO_x emissions from existing industrial coal-fired boilers.

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

(a) Selective Catalytic Reduction (70% - 90% Control)
(b) Selective Non-Catalytic Reduction (30% - 50% Control)
(g) Good Combustion Practices (Less than 40% Control)
(f) Low Excess Air (10% - 20% Control)

Step 4 - Evaluate the Most Effective Controls

Fort Wainwright BACT Proposal

Fort Wainwright provided an economic analysis for the installation of selective catalytic reduction and selective non-catalytic reduction. A summary of the analysis is shown below:

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

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annual Costs ($/year)	Cost Effectiveness ($/ton)
SCR	177	88	$13,860,931	$2,222,777	$25,166
SNCR	105	52	$5,598,476	$936,162	$17,852
Capital Recovery Factor = 0.1424 (7% interest rate for a 10 year equipment life)					

Fort Wainwright contends that the economic analysis indicates the level of NOx reduction does not justify the use of selective catalytic reduction or selective non-catalytic reduction for the coal-fired boilers based on the excessive cost per ton of NOx removed per year.

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

(a) NOx emissions from the operation of the coal-fired boilers will be controlled with good combustion practices and injection of overfire air with oxygen trim systems.

(b) NOx emissions from the coal-fired boilers will not exceed 0.46 lb/MMBtu over a 3-hour averaging period.

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

Department Evaluation of BACT for NOx Emissions from the Industrial Coal-Fired Boilers

The Department revised the cost analyses provided by Fort Wainwright for the installation of SCR and SNCR using the cost estimating procedures identified in EPA's May 2016 Air Pollution Control Cost Estimation Spreadsheet for Selective Catalytic Reduction,[5] and Selective Non-Catalytic Reduction,[6] a baseline emission rate of 0.58 lb NOx/MMBtu,[7] a retrofit factor of 1.5 for a difficult retrofit, a NOx removal efficiency of 90% and 50% for SCR and SNCR respectively, an interest rate of 5.0% (current bank prime interest rate), and a 20 year equipment life. A summary of the analysis is shown below:

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

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR	241	217	$15,295,700	$1,565,833	$7,214
SNCR	241	121	$4,209,767	$521,542	$4,325
Capital Recovery Factor = 0.0802 (5.0 % interest rate for a 20 year equipment life)					

The Department's economic analysis indicates the level of NOx reduction justifies the use of selective catalytic reduction or selective non-catalytic reduction as BACT for the coal-fired boilers located in the Serious PM-2.5 nonattainment area.

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

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

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

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

5 https://www3.epa.gov/ttn/ecas/docs/scr_cost_manual_spreadsheet_2016_vf.xlsm

6 https://www3.epa.gov/ttn/ecas/docs/sncr_cost_manual_spreadsheet_2016_vf.xlsm

7 Emission factor from AP-42 Table 1.1-3 for spreader stoker sub-bituminous coal (8.8 lb NOx/ton) and converted to lb/MMBtu using heat value for Usibelli Coal of 7,560 Btu/lb, http://www.usibelli.com/coal/data-sheet.

(b) NOx emissions from DU EUs 1 through 6 shall not exceed 0.060 lb/MMBtu averaged over a 3-hour period; and

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

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

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

Facility	Process Description	Capacity	Limitation	Control Method
Fort Wainwright	6 Coal-Fired Boilers	1,380 MMBtu/hr	0.06 lb/MMBtu[8]	Selective Catalytic Reduction
UAF	Dual Fuel-Fired Boiler	295.6 MMBtu/hr	0.04 lb/MMBtu[9]	Selective Catalytic Reduction
Chena	4 Coal-Fired Boilers	497 MMBtu/hr	0.402 lb/MMBtu[10]	Good Combustion Practices

3.2 NOx BACT for the Diesel-Fired Boilers

Possible NOx 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 3-5.

Table 3-5. RBLC Summary of NOx Control for Diesel-Fired Boilers

Control Technology	Number of Determinations	Emission Limits (g/hp-hr)
Low-NOx Burner	8	0.023 - 0.14
Good Combustion Practices	1	0.01
No Control Specified	2	0.070 - 0.12

RBLC Review

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

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

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

(a) Low NOx Burners (LNBs)

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

[9] Calculated using a 80% NOx control efficiency for SCR with uncontrolled emission rate from 40 C.F.R. 60.44b(l)(1) [NSPS Subpart Db].

[10] Emission rate averaged from two most recent NOx source tests at Chena Power Plant accepted by the Department which occurred on November 19, 2011 and July 12, 2019.

The theory of LNBs was discussed in detail in the NOx BACT for the coal-fired boilers and will not be repeated here. The Department considers LNB 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 NOx BACT for the coal-fired boilers and will not be repeated here. The Department considers GCPs a technically feasible control technology for the diesel-fired boilers.

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

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

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

(b)	Limited Operation	(94% Control)
(a)	Low NOx Burners	(35% - 55% 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 NOx 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

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

The Department reviewed Fort Wainwright's proposal and finds that the 27 diesel-fired boilers have a combined potential to emit (PTE) of less than 12 tons per year (tpy) for NOx. At 12 tpy, the cost effectiveness in terms of dollars per ton for add-on pollution control for these units is economically infeasible.

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

(a) NOx emissions from the diesel-fired boilers shall not exceed 0.15 lb/MMBtu[11];
(b) Combined operating limit of 600 hours per year for FWA EUs 8, 9, and 10;
(c) Maintain good combustion practices by following the manufacturer's maintenance procedures at all times of operation.

Table 3-6 lists the proposed NOx BACT determination for this facility along with those for other diesel-fired boilers rated at less than 100 MMBtu/hr in the Serious PM-2.5 nonattainment area.

Table 3-6. Comparison of NOx BACT for the Diesel-Fired Boilers at Nearby Power Plants

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

3.3 NOx BACT for the Large Diesel-Fired Engines, Fire Pumps, and Generators

Possible NOx emission control technologies for large engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 17.100 to 17.190, Large Internal Combustion Engines (>500 hp). The search results for large diesel-fired engines are summarized in Table 3-7.

Table 3-7. RBLC Summary of NOx Control for Large Diesel-Fired Engines

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

RBLC Review
A review of similar units in the RBLC indicates selective catalytic reduction, good combustion practices, and compliance with the federal emission standards are the principle NOx control

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

technologies installed on large diesel-fired engines. The lowest NOx emission rate listed in the RBLC is 0.5 g/hp-hr.

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

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

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

(c) Fuel Injection Timing Retard (FITR)
FITR reduces NOx emissions by the delay of the fuel injection in the engine from the time the compression chamber is at minimum volume to a time the compression chamber is expanding. Timing adjustments are relatively straightforward. The larger volume in the compression chamber produces a lower peak flame temperature. With the use of FITR the engine becomes less fuel efficient, particulate matter emissions increase, and there is a limit with respect to the degree the timing may be retarded because an excessive timing delay can cause the engine to misfire. The timing retard is generally limited to no more than three degrees. Diesel engines may also produce more black smoke due to a decrease in exhaust temperature and incomplete combustion. FITR can achieve up to 50 percent NOx reduction. Due to the increase in particulate matter emissions resulting from FITR, this technology will not be carried forward.

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

(e) Federal Emission Standards
RBLC NOx determinations for federal emission standards require the engines meet the requirements of 40 C.F.R. 60 Subpart IIII, 40 C.F.R 63 Subpart ZZZZ, non-road engines

(NREs), or EPA tier certifications. Subpart IIII applies to stationary compression ignition internal combustion engines that are manufactured or reconstructed after July 11, 2005. The Department considers meeting the technology based New Source Performance Standards (NSPS) of Subpart IIII as a technically feasible control technology for the large diesel-fired engines.

(f) 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 Prevention of Significant Deterioration (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.

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

Step 2 - Eliminate Technically Infeasible NOx Control Technologies for the Large Engines
As explained in Step 1 of Section 3.3, the Department does not consider fuel injection timing retard and ignition timing retard as technically feasible technologies to control NOx emissions from the large diesel-fired engines.

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

(f)	Limited Operation	(94% Control)
(a)	Selective Catalytic Reduction	(90% Control)
(g)	Good Combustion Practices	(Less than 40% Control)
(b)	Turbocharger and Aftercooler	(6% – 12% Control)
(e)	Federal Emission Standards	(Baseline)

Step 4 - Evaluate the Most Effective Controls

Fort Wainwright BACT Proposal

Fort Wainwright proposes the following as BACT for NOx 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) 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.

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

The Department reviewed Fort Wainwright's proposal and finds that NOx emissions from the large diesel-fired engines can additionally 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 NOx BACT for the Large Diesel-Fired Engines

The Department's finding is that the BACT for NOx 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 per year;

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

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

(e) Comply with the numerical BACT emission limits listed in Table 3-8 for NOx. For the engines subject to 40 C.F.R. 60 Subpart IIII, demonstrate compliance with the numerical BACT emission limits by complying with the applicable NOx emission standards in Subpart IIII.

Table 3-8 Proposed NOx BACT Limits for the Large Diesel-Fired Engines

Location	EU	Year	Description	Size	Status	BACT Limit	Proposed BACT
DU	8	2009	Generator Engine	2,937 hp	Certified Engine	4.8 g/hp-hr	Limited Operation of 500 hours per year each Good Combustion Practices
FWA	50	2010	Generator Engine	762 hp	Certified Engine	4.8 g/hp-hr	Limited Operation for Non-Emergency Use (100 hours per year each) Good Combustion Practices
FWA	51	2010	Generator Engine	762 hp	Certified Engine	4.8 g/hp-hr	
FWA	53	2008	Generator Engine	587 hp	Certified Engine	3.0 g/hp-hr	
FWA	54	2005	Generator Engine	1,059 hp	Manufacturer Information	5.75 g/hp-hr	
FWA	11	2003	Caterpillar 3512	1,206 hp	AP-42 Table 3.4-1	10.9 lb/hp-hr	Limit combined operation to 600 hours per year
FWA	12	2003	Caterpillar 3512	1,206 hp	AP-42 Table 3.4-1	10.9 lb/hp-hr	
FWA	13	2003	Caterpillar 3512	1,206 hp	AP-42 Table 3.4-1	10.9 lb/hp-hr	

Table 3-9 lists the proposed NOx 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 3-9. Comparison of NOx BACT for Large Diesel-Fired Engines at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
Fort Wainwright	8 Large Diesel-Fired Engines	> 500 hp	3.0 – 10.9 g/hp-hr	Limited Operation Good Combustion Practices Federal Emission Standards
UAF	Large Diesel-Fired Engine	13,266 hp	1.3 g/hp-hr	Selective Catalytic Reduction Turbocharger and Aftercooler Good Combustion Practices Limited Operation
GVEA North Pole	Large Diesel-Fired Engine	600 hp	10.9 g/hp-hr	Turbocharger and Aftercooler Good Combustion Practices Limited Operation
GVEA Zehnder	2 Large Diesel-Fired Engines	11,000 hp (each)	3.7 g/hp-hr	Turbocharger and Aftercooler Good Combustion Practices Limited Operation

3.4 NOx BACT for the Small Emergency Engines, Fire Pumps, and Generators

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

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

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

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

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

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

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

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

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

(e) Limited Operation
Limiting the operation of emission units reduces the potential to emit for those units. The Department considers limited operation as a technically feasible control technology for the small diesel-fired engines.

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

Step 2 - Eliminate Technically Infeasible NOx Control Technologies for the Small Engines
As explained in Step 1 of Section 3.4, the Department does not consider ignition timing retard as a technically feasible technology to control NOx emissions from the small diesel-fired engines.

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

(e)	Limited Operation	(94% Control)
(a)	Selective Catalytic Reduction	(90% Control)
(b)	Turbocharger and Aftercooler	(6% – 12% Control)
(f)	Good Combustion Practices	(Less than 40% 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 NOx emissions from the small diesel-fired engines:

(a) Good Combustion Practices; and

(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.

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

The Department reviewed Fort Wainwright's proposal and found that in addition to maintaining good combustion practices and complying with federal emission standards, limiting operation of the small diesel-fired engines during non-emergency operation to no more than 100 hours per year each is BACT for NOx emissions.

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

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

(a) Limit non-emergency operation of DU EUs 9, 14, 22, 23, 29a, 30, 31a, 32, 33, 34, 35, 36, FWA EUs 26 through 39, 52 and 55 through 65 to no more than 100 hours per year each;

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

(c) Comply with the numerical BACT emission limits listed in Table 3-11 for NOx.

Table 3-11. Proposed NOx BACT Limits for the 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	0.031 lb/hp-hr	Limited Operation for Non-Emergency Use (100 hours per year each) Good Combustion Practices
DU	14	2008	Generator Engine	320 hp	Certified Engine	4.0 g/kW-hr	
DU	22	1989	Generator Engine	35 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
DU	23	2003	Generator Engine	155 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
DU	30	1952	Lift Pump Engine	75 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
DU	32	1955	Lift Pump Engine	75 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
DU	33	1994	Lift Pump Engine	75 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
DU	34	1995	Well Pump Engine	220 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
DU	35	2009	Well Pump Engine	55 hp	Certified Engine	4.7 g/kW-hr	
DU	36	1995	Well Pump Engine	220 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
DU	29a	2014	Lift Pump Engine	74 hp	Certified Engine	4.7 g/kW-hr	
DU	31a	2014	Lift Pump Engine	74 hp	Certified Engine	4.7 g/kW-hr	
FWA	26	2012	QSB7-G3 NR3	295 hp	Certified Engine	4.0 g/kW-hr	
FWA	27	2009	4024HF285B	67 hp	Certified Engine	4.7 g/kW-hr	
FWA	28	2007	CAT C9 GENSET	398 hp	Certified Engine	4.0 g/kW-hr	
FWA	29	ND	TM30UCM	47 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
FWA	30	2007	JW64-UF30	275 hp	Certified Engine	4.0 g/kW-hr	
FWA	31	1994	DDFP-04AT	235 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
FWA	32	1994	DDFP-04AT	235 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
FWA	33	1994	DDFP-04AT	235 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
FWA	34	1994	DDFP-04AT	235 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
FWA	35	1977	N-855-F	240 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
FWA	36	1977	N-855-F	240 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	

Location	EU	Year	Description	Size	Status	BACT Limit	Proposed BACT
FWA	37	2005	JU4H-UF40	94 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
FWA	38	1996	PDFP-06YT	120 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
FWA	39	1996	PDFP-06YT	120 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
FWA	52	2002	Generator Engine	82 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
FWA	55	2005	Generator Engine	212 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
FWA	56	2007	Generator Engine	176 hp	Permit condition 23.1c	6.9 g/hp-hr	
FWA	57	2005	Generator Engine	212 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
FWA	58	2007	Generator Engine	71 hp	Certified Engine	7.5 g/kW-hr	
FWA	59	1976	Generator Engine	35 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
FWA	60	2001	Generator Engine	95 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
FWA	61	1993	Generator Engine	50 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
FWA	62	2011	Generator Engine	18 hp	Certified Engine	7.5 g/kW-hr	
FWA	63	2003	Generator Engine	68 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
FWA	64	2010	Generator Engine	274 hp	Certified Engine	4.0 g/kW-hr	
FWA	65	2010	Generator Engine	274 hp	Certified Engine	4.0 g/kW-hr	

Table 3-12 lists the proposed NOx BACT determination for this facility along with those for other diesel-fired engines rated at less than 500 hp located in the Serious PM-2.5 nonattainment area.

Table 3-12. Comparison of NOx BACT for Small Diesel Engines at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
Fort Wainwright	41 Small Diesel-Fired Engines	< 500 hp	0.007 – 0.031 lb/hp-hr	Limited Operation for Non-Emergency Use (100 hours per year each) Good Combustion Practices
UAF	Six Small Diesel-Fired Engines	< 500 hp	0.0007 – 0.031 lb/hp-hr	Turbocharger and Aftercooler Good Combustion Practices Limited Operation

4. BACT DETERMINATION FOR PM-2.5

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

4.1 PM-2.5 BACT for the 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.

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,[12] pulse-jet,[13] and reverse-air.[14] Fabric filter systems have control efficiencies of 95% to 99.9%, and are generally specified to meet a discharge concentration of filterable particulate (e.g., 0.01 grains per dry standard cubic feet). The Department considers fabric filters a technically feasible control technology for the 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%.[15] 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%.[16] The

[12] https://www3.epa.gov/ttn/catc/dir1/ff-shaker.pdf
[13] https://www3.epa.gov/ttn/catc/dir1/ff-pulse.pdf
[14] https://www3.epa.gov/ttn/catc/dir1/ff-revar.pdf
[15] https://www3.epa.gov/ttn/catc/dir1/fwespwpi.pdf
https://www3.epa.gov/ttn/catc/dir1/fwespwpl.pdf
[16] 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%.[17] One advantage of wet scrubbers is that they can be effective on condensable particulate matter. A disadvantage of wet scrubbers is that they consume water and produce water and sludge. For fine particulate control, a venturi scrubber can be used, but typical loadings for such a scrubber are 0.1-50 grains/scf. The Department considers the use of wet scrubbers 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

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

The theory of GCPs was discussed in detail in the NOx BACT 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 industrial 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 to obtain an emission rate.

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) at all times the units are in operation;

(b) PM-2.5 emissions from DU EUs 1 through 6 shall not exceed 0.045 lb/MMBtu[18] averaged over a 3-hour period; and

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

[18] The 0.045 lb/MMBtu emission rate is calculated using EPA AP-42 Tables 1.1-5 and 1.1-6 for spreader stoker boilers with a baghouse; converted to lb/MMBtu using the typical gross as received heat value (7,560 Btu/lb) and ash content (7 percent) of Usibelli coal identified in the coal data sheet at: http://usibelli.com/coal/data-sheet.

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	Full stream baghouse
UAF	Dual Fuel-Fired Boiler	295.6 MMBtu/hr	0.012 lb/MMBtu[19]	Fabric Filters

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.

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 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 NOx BACT for the industrial coal-fired boilers and will not be repeated here. Proper management of the combustion process

[19] Boiler manufacturer Babcock & Wilcox's PM-2.5 emission guarantee, used to calculate potential to emit in Air Quality Permit AQ0316MSS06.

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 27 diesel-fired boilers 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.

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 is as follows:

(a) PM-2.5 emissions from the diesel-fired boilers shall not exceed 0.012 lb/MMBtu[20] averaged over a 3-hour period, with the exception of the waste fuel boilers which must comply with the State particulate matter emissions standard of 0.05 grains per dry standard cubic foot under 18 AAC 50.055(b)(1);

(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 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	27 Diesel-Fired Boilers	< 100 MMBtu/hr	0.012 lb/MMBtu[20]	Good Combustion Practices
UAF	3 Diesel-Fired Boilers	< 100 MMBtu/hr	0.012 lb/MMBtu[20]	Limited Operation

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

Facility	Process Description	Capacity	Limitation	Control Method
				Good Combustion Practices
Zehnder	2 Diesel-Fired Boilers	< 100 MMBtu/hr	0.012 lb/MMBtu[20]	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.

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 NOx BACT 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	

Location	EU	Year	Description	Size	Status	BACT Limit	Proposed BACT
FWA	12	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	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 Engine	13,266 hp	0.32 g/hp-hr	Positive Crankcase Ventilation 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
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 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 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 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 NOx BACT 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, 30, 31a, 32, 33, 34, 35, 36, FWA EUs 26 through 39, 52, and 55 through 65 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
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	30	1952	Lift Pump Engine	75 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
DU	32	1955	Lift Pump Engine	75 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
DU	33	1994	Lift Pump Engine	75 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	

Location	EU	Year	Description	Size	Status	BACT Limit	Proposed BACT
DU	34	1995	Well Pump Engine	220 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	Combust ULSD
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	29a	2014	Lift Pump Engine	74 hp	Certified Engine	0.3 g/kW-hr	
DU	31a	2014	Lift Pump Engine	74 hp	Certified Engine	0.3 g/kW-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	
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	60	2001	Generator Engine	95 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-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	

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	41 Small Diesel-Fired Engines	< 500 hp	0.015 – 1.0 g/hp-hr	Good Combustion Practices Limited Operation
UAF	One Small Diesel-Fired Engine	< 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 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 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 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 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 EUs 7a – 7c, 51a, and 51b shall be controlled by operating and maintaining fabric filters 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	Limited Operation – This source serves as backup to EU 7a and operates less than 200 hours each year

EU ID	Description	Current Control	BACT Limit	Proposed BACT Control
52	Emergency Coal Storage Pile and Operations	Follow Fugitive Dust Control Plan	Dust Control Plan[21]	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.

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

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

[21] 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.

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.

(e) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT 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.

Step 2 - Eliminate Technically Infeasible SO_2 Control Technologies for Coal-Fired Boilers
All identified control devices are technically feasible for the industrial coal-fired boilers.

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)
(b) Spray Dry Absorbers (90% Control)
(c) Dry Sorbent Injection (Duct Sorbent Injection) (50 – 80% Control)
(d) Low Sulfur Coal (30% Control)
(e) Good Combustion Practices (Less than 40% Control)

Step 4 - Evaluate the Most Effective Controls

Fort Wainwright BACT Proposal

Fort Wainwright provided an economic analysis of the installation of wet and dry scrubber 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)
Wet Scrubber	1,767	1,749	???	???	6,900 - 13,800
Spray-Dry Scrubber	1,767	1,590	???	???	5,200 - 6,200
Dry Sorbent Injection[22]	1,767	1,414	6,191,696	6,384,196	4,516 - 5,968
Capital Recovery Factor = 0.1424 (7% interest rate for a 10 year equipment life)					

Fort Wainwright contends that the economic analysis indicates the level of SO_2 reduction does not justify the use of wet scrubbers, semi-dry scrubbers, or dry scrubber systems (dry-sorbent injection) for the coal-fired boilers based on the excessive cost per ton of SO_2 removed per year.

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.

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

(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 300,000 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 revised the cost analysis provided for the installation of wet scrubbers, semi-dry scrubbers (spray dry absorbers), and dry scrubbers (dry sorbent injection) using a potential to emit of 1,476 tpy for the six coal-fired boilers combined or 246 tpy individually (calculated using the existing permit limit of 336,000 tons of coal per year combined), a baseline emission rate of 0.58 lb SO_2/MMBtu,[23] a retrofit factor of 1.5 for difficult retrofits, a SO_2 removal efficiency of 99%, 90% and 80% for wet scrubbers, spray dry absorbers and dry sorbent injection respectively, an interest rate of 50% (current bank prime interest rate), and a 15 year equipment life. A summary of the analysis is shown below in Table 5-3. Note that the analysis for wet scrubbers and spray dry absorbers includes the six coal-fired boilers combined, while the analysis for the dry sorbent injection system is for each individual boiler:

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)
Wet Scrubber	1,473	1,459	139,740,006	23,856,873	16,356
Spray Dry Absorbers	1,473	1,326	126,965,456	21,926,184	16,748
Dry Sorbent Injection	246	196	3,675,500	2,236,001	11,383
Capital Recovery Factor = 0.0963 (5.0% interest rate for a 15 year equipment life)					

The Department's economic analysis indicates the level of SO_2 reduction justifies the use of dry sorbent injection as BACT for the 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:

[23] Calculated assuming a 0.25% sulfur content by weight (SIP limit, gross as received) and a higher heating value of 7,560 Btu/lb for Healy coal (average of gross as received range) http://www.usibelli.com/coal/data-sheet, and AP-42 Table 1.1-3 emission factors for spreader stoker boilers combusting sub-bituminous coal.

(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 0.12 lb/MMBtu[24] 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
Fort Wainwright	6 Coal-Fired Boilers	1380 MMBtu/hr (combined)	0.12 lb/MMBtu[24]	Dry Sorbent Injection Limited Operation Low Sulfur Coal
UAF	Dual Fuel-Fired Boiler	295.6 MMBtu/hr	0.10 lb/MMBtu	Dry Sorbent Injection Limestone Injection Low Sulfur Coal
Chena	4 Coal-Fired Boilers	497 MMBtu/hr (combined)	0.10 lb/MMBtu	Dry Sorbent Injection Low Sulfur Coal

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 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

[24] BACT limit selected after evaluating existing emission limits in the RBLC database for coal-fired boilers, taking into account previous source test data from coal-fired boilers in Alaska and actual emissions data from other sources employing similar types of controls, using site specific vendor quotes provided by Amerair Industries LLC. and Black & Veatch Corporation, and in-line with EPA's pollution control Fact Sheets while keeping in mind that BACT limits must be achievable at all times.

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 NOx BACT 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 27 diesel fired boilers have a combined PTE of less than 25 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 except for the waste oil 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 is as follows:

(a) SO_2 emissions from the diesel-fired boilers shall be controlled by only combusting ULSD, with the exception of the waste fuel boilers;

(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	Diesel-Fired Boilers	< 100 MMBtu/hr	15 ppmw S in fuel	Good Combustion Practices Ultra-Low Sulfur Diesel
	Waste Fuel-Fired Boilers		0.5 % S by weight	Good Combustion Practices
UAF	3 Diesel-Fired Boilers	< 100 MMBtu/hr	15 ppmw S in fuel	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

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 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
The theory of federal emission standards was discussed in detail in the NOx BACT for the large diesel-fired engines and will not be repeated here. 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 NOx BACT 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 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 NOx BACT 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, 30, 31a, 32, 33, 34, 35, 36, FWA EUs 26 through 39, 52, and 55 through 65 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 5-10. Comparison of SO_2 BACT for Small Diesel-Fired Engines at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
Fort Wainwright	41 Small Diesel-Fired Engines	< 500 hp	15 ppmw S in fuel	Limited Operation Ultra-Low Sulfur Diesel Good Combustion Practices
UAF	Six Small Diesel-Fired 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	Proposed BACT Control
DU 1	Six Coal Fired Boiler 3	230 MMBtu/hr	0.06 lb/MMBtu	Selective Catalytic Reduction
DU 2	Six Coal Fired Boiler 4	230 MMBtu/hr	0.06 lb/MMBtu	
DU 3	Six Coal Fired Boiler 5	230 MMBtu/hr	0.06 lb/MMBtu	
DU 4	Six Coal Fired Boiler 6	230 MMBtu/hr	0.06 lb/MMBtu	
DU 5	Six Coal Fired Boiler 7	230 MMBtu/hr	0.06 lb/MMBtu	
DU 6	Six Coal Fired Boiler 8	230 MMBtu/hr	0.06 lb/MMBtu	
FWA 8	Backup Diesel-Fired Boiler 1	19 MMBtu/hr	0.15 lb/MMBtu	Good Combustion Practices Limited Operation (600 hours/year combined)
FWA 9	Backup Diesel-Fired Boiler 2	19 MMBtu/hr	0.15 lb/ MMBtu	
FWA 10	Backup Diesel-Fired Boiler 3	19 MMBtu/hr	0.15 lb/ MMBtu	
N/A	Diesel-Fired Boilers (24)	Varies	0.15 lb/ MMBtu	Good Combustion Practices
DU 8	Generator Engine	2,937 hp	4.8 g/hp-hr	Good Combustion Practices Limited Operation (100 hours/year each, for non-emergency operation)
FWA 50	Generator Engine	762 hp	4.8 g/hp-hr	
FWA 51	Generator Engine	762 hp	4.8 g/hp-hr	
FWA 53	Generator Engine	587 hp	3.0 g/hp-hr	
FWA 54	Generator Engine	1,059 hp	5.75 g/hp-hr	
FWA 11	Caterpillar 3512	1,206 hp	10.9 g/hp-hr	Good Combustion Practices Limited Operation (600 hours/year combined)
FWA 12	Caterpillar 3512	1,206 hp	10.9 g/hp-hr	
FWA 13	Caterpillar 3512	1,206 hp	10.9 g/hp-hr	
DU 9	Generator Engine	353 hp	0.031 lb/hp-hr	Good Combustion Practices Limited Operation (100 hours/year each, for non-emergency operation)
DU 14	Generator Engine	320 hp	4.0 g/kW-hr	
DU 22	Generator Engine	35 hp	0.031 lb/hp-hr	
FWA 52	Generator Engine	82 hp	0.031 lb/hp-hr	
FWA 55	Generator Engine	212 hp	0.031 lb/hp-hr	
FWA 56	Generator Engine	176 hp	6.9 lb/hp-hr	
FWA 57	Generator Engine	212 hp	0.031 lb/hp-hr	
FWA 58	Generator Engine	71 hp	7.5 g/kW-hr	
FWA 59	Generator Engine	35 hp	0.031 lb/hp-hr	
FWA 60	Generator Engine	95 hp	0.031 lb/hp-hr	

EU ID	Description	Capacity	Proposed BACT Limit	Proposed BACT Control
FWA 23	Generator Engine	155 hp	0.031 lb/hp-hr	Good Combustion Practices Limited Operation (100 hours/year each, for non-emergency operation)
FWA 61	Generator Engine	50 hp	0.031 lb/hp-hr	
FWA 62	Generator Engine	18 hp	7.5 g/kW-hr	
FWA 63	Generator Engine	68 hp	0.031 lb/hp-hr	
FWA 64	Generator Engine	274 hp	4.0 g/kW-hr	
FWA 65	Generator Engine	274 hp	4.0 g/kW-hr	
DU 30	Lift Pump Engine	75 hp	0.031 lb/hp-hr	
DU 32	Lift Pump Engine	75 hp	0.031 lb/hp-hr	
DU 33	Lift Pump Engine	75 hp	0.031 lb/hp-hr	
DU 34	Well Pump Engine	220 hp	0.031 lb/hp-hr	
DU 35	Well Pump Engine	55 hp	4.7 g/hp-hr	
DU 36	Well Pump Engine	220 hp	0.031 lb/hp-hr	
DU 29a	Lift Pump Engine	74 hp	4.7 g/kW-hr	
DU 31a	Lift Pump Engine	74 hp	4.7 g/kW-hr	
FWA 26	QSB7-G3 NR3	295 hp	4.0 g/kW-hr	
FWA 27	4024HF285B	67 hp	4.7 g/kW-hr	
FWA 28	CAT C9 GENSET	398 hp	4.0 g/kW-hr	
FWA 29	TM30UCM	47 hp	0.031 lb/hp-hr	
FWA 30	JW64-UF30	275 hp	4.0 g/kW-hr	
FWA 31	DDFP-04AT	235 hp	0.031 lb/hp-hr	
FWA 32	DDFP-04AT	235 hp	0.031 lb/hp-hr	
FWA 33	DDFP-04AT	235 hp	0.031 lb/hp-hr	
FWA 34	DDFP-04AT	235 hp	0.031 lb/hp-hr	
FWA 35	N-855-F	240 hp	0.031 lb/hp-hr	
FWA 36	N-855-F	240 hp	0.031 lb/hp-hr	
FWA 37	JU4H-UF40	94 hp	0.031 lb/hp-hr	
FWA 38	PDFP-06YT	120 hp	0.031 lb/hp-hr	
FWA 39	PDFP-06YT	120 hp	0.031 lb/hp-hr	

Table 6-2. Proposed PM-2.5 BACT Limits

EU ID	Description	Capacity	Proposed BACT Limit	Proposed BACT Control
DU 1	Six Coal Fired Boiler 3	230 MMBtu/hr	0.045 lb/MMBtu	Full stream baghouse
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	0.012 lb/MMBtu	Good Combustion Practices Limited Operation (600 hours/year combined) Combust ULSD
FWA 9	Backup Diesel-Fired Boiler 2	19 MMBtu/hr	0.012 lb/MMBtu	
FWA 10	Backup Diesel-Fired Boiler 3	19 MMBtu/hr	0.012 lb/MMBtu	
N/A	Diesel-Fired Boilers	Varies	0.012 lb/MMBtu	Good Combustion Practices Combust ULSD
DU 8	Generator Engine	2,937 hp	0.15 g/hp-hr	40 CFR 60 Subpart IIII Combust ULSD Good Combustion Practices Limited Operation (100 hours/year each, for non-emergency operation)
DU 13	Generator Engine	587 hp	0.15 g/hp-hr	
FWA 50	Generator Engine	762 hp	0.15 g/hp-hr	
FWA 51	Generator Engine	762 hp	0.15 g/hp-hr	
FWA 54	Generator Engine	1,059 hp	0.32 g/hp-hr	Limited Operation (100 hours/year, for non-emergency operation) Good Combustion Practices Combust ULSD
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

EU ID	Description	Capacity	Proposed BACT Limit	Proposed BACT Control
DU 14	Generator Engine	320 hp	0.2 g/kW-hr	(100 hours/year each, for non-emergency operation) Good Combustion Practices Combust ULSD
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 60	Generator Engine	95 hp	2.20 E-3 lb/hp-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	
DU 30	Lift Pump Engine	75 hp	2.20 E-3 lb/hp-hr	
DU 32	Lift Pump Engine	75 hp	2.20 E-3 lb/hp-hr	
DU 33	Lift Pump Engine	75 hp	2.20 E-3 lb/hp-hr	
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 31a	Lift Pump Engine	74 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

EU ID	Description	Capacity	Proposed BACT Limit	Proposed BACT Control
FWA 34	DDFP-04AT	235 hp	2.20 E-3 lb/hp-hr	(100 hours/year each, for non-emergency operation) Good Combustion Practices Combust ULSD
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	94 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	Proposed BACT Control
7a	South Coal Handling Dust Collector	0.0025 gr/dscf	Enclosed emission points and follow manufacturer recommendations for operations and maintenance
7b	South Underbunker Dust Collector	0.02 gr/dscf	Enclosed emission points and follow manufacturer recommendations for operations and maintenance
7c	North Coal Handling Dust Collector	0.02 gr/dscf	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	Chemical Stabilizers, Wind Fencing, Covered Haul Vehicles, Watering, and Wind Awareness
51a	Fly Ash Dust Collector	0.02 gr/dscf	Enclosed emission points and follow manufacturer recommendations for operations and maintenance
51b	Bottom Ash Dust Collector	0.02 gr/dscf	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	Proposed BACT Control
DU 1	Six Coal Fired Boiler 3	230 MMBtu/hr	0.12 lb/MMBtu	Dry Sorbent Injection Limited Operation (336,000 tons/year combined) Low Sulfur Coal
DU 2	Six Coal Fired Boiler 4	230 MMBtu/hr	0.12 lb/MMBtu	
DU 3	Six Coal Fired Boiler 5	230 MMBtu/hr	0.12 lb/MMBtu	
DU 4	Six Coal Fired Boiler 6	230 MMBtu/hr	0.12 lb/MMBtu	
DU 5	Six Coal Fired Boiler 7	230 MMBtu/hr	0.12 lb/MMBtu	
DU 6	Six Coal Fired Boiler 8	230 MMBtu/hr	0.12 lb/MMBtu	
FWA 8	Backup Diesel-Fired Boiler 1	19 MMBtu/hr	15 ppmv S in fuel	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	
N/A	Diesel-Fired Boilers	Varies	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) Good Combustion Practices Combust ULSD
DU 13	Generator Engine	587 hp	15 ppmv S in fuel	
DU 15	Generator Engine	1,059 hp	15 ppmv S in fuel	
FWA 50	Generator Engine	762 hp	15 ppmv S in fuel	
FWA 51	Generator Engine	762 hp	15 ppmv S in fuel	
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 Combust ULSD
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	
FWA 52	Generator Engine	82 hp	15 ppmv S in fuel	
FWA 55	Generator Engine	212 hp	15 ppmv S in fuel	
FWA 56	Generator Engine	176 hp	15 ppmv S in fuel	

EU ID	Description	Capacity	Proposed BACT Limit	Proposed BACT Control
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 60	Generator Engine	95 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	
DU 30	Lift Pump Engine	75 hp	15 ppmv S in fuel	
DU 32	Lift Pump Engine	75 hp	15 ppmv S in fuel	
DU 33	Lift Pump Engine	75 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 31a	Lift Pump Engine	74 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	
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	94 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	

ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION

18 AAC 50 AIR QUALITY CONTROL

Response to Comments on May 14, 2019, Proposed Regulations:

Fort Wainwright

November 13, 2019

Table of Contents

Introduction

This document provides the Alaska Department of Environmental Conservation's (ADEC) response to public comments received regarding the May 14, 2019, draft regulations pertaining to regulation changes relating to fine particulate matter (PM-2.5) including new and revised air quality controls and a new State Implementation Plan comprised of 15 sections covering monitoring, modeling, control measures, emission inventory, attainment demonstration, and episode plan, which are intended to meet federal requirements for the serious nonattainment area within the Fairbanks North Star Borough (FNSB).

The details describing the proposed regulation changes were presented in ADEC's public notice dated May 14, 2019. ADEC received emailed comments, hand written comments at ADEC's open house, oral testimony at ADEC's public hearings, and comments submitted via the Air Quality Division's online comment system.

This document responds to individual comments from the Environmental Protection Agency (EPA) and aggregated comments from the public. For each section of the proposed regulations and for the State Implementation Plan (SIP), the document summarizes the comments received and provides ADEC's response.

Opportunities for Public Comment

The public notice dated May 14, 2019, provided information on the opportunities for the public to submit comments. The deadline to submit comments was July 26, 2019 at 5:00 p.m. This provided a 73 day period for the public to review the proposal and submit comments.

Opportunities to submit written comments included submitting electronic comments using the Air Quality Division's online comment form, submitting electronic comments via email, submitting written comments via facsimile, and submitting written comments via email.

Opportunities to submit oral comments included a daytime and an evening public hearing held in Fairbanks on June 26, 2019. The hearings provided the opportunity for the public to submit oral comments.

1. Comments from Doyon Utilities, LLC.

1a. General Comments

Doyon Utilities Comment (1):

Section 7.7.8.3 of the proposed SIP document states incorrectly that the Fort Wainwright (FWA) Central Heat and Power Plant (CHPP) emissions units "are operated by a private utility company, Doyon Utilities, LLC (DU) and owned by the US Army Garrison Fort Wainwright."

The Central Heat and Power Plant (CHPP) was owned and operated by the Department of Defense until formally transferred to Doyon Utilities on August 15, 2008. Prior to transfer, Department of Defense solicited proposals for privatization of the CHPP and other electric and steam utility assets. DU was the successful bidder and signed a 50-year contract on September 28, 2007 to become the new owner and operator. For more than ten years, Doyon Utilities has owned and operated the plant under the economic jurisdiction of the Regulatory Commission of Alaska Certificate of Public Convenience and Necessity #725. Under the regulated model, DU recovers operating and capital costs through rates established by the RCA. In addition to economic regulation, DU is subject to environmental regulation as well. DU has held a series of air permits from ADEC for the emissions units in the CHPP. The Army does not maintain a physical presence at any of DU's facilities, nor is the Army responsible for day to day operational discussions. As the customer who pays for utility services via tariff rates, the Army is interested in compliance issues of DU's facilities.

Response:

The Department made a technical correction to Section 7.7.8.3 of the SIP Control Strategies chapter to clarify that the EUs at the CHPP are owned and operated by Doyon Utilities, LLC (DU).

Doyon Utilities Comment (2):

Section 7.7.8.3 of the proposed SIP document and Tables A and B of the proposed Best Available Control Technology (BACT) Determination do not reflect the asset transfer of several generator engines from DU to the Army in late December 2018. The documents identify those engines as DU emissions units instead of Army garrison emissions units. DU submitted a notification of these changes to the Alaska Department of Environmental Conservation (ADEC) on December 31, 2018. See Attachment 2 for a copy of this notification.

Response:

The Department revised the emissions unit inventory to reflect the transfer of the EUs from DU to the Army.

Doyon Utilities Comment (3):

In some instances, the proposed SIP document and the underlying proposed BACT Determination are inconsistent with respect to applicable emissions limits and other requirements. Because both documents will become part of the SIP, please ensure that these two documents are internally consistent and clearly state which requirements are applicable to each emissions unit. DU has attempted to address specific inconsistencies in the subsequent comments.

Response:

The Department revised the SIP Control Strategies chapter and the BACT Determination to ensure consistency with respect to applicable emissions limits. The Department included Table 4-9 from the BACT Determination into the SIP Control Strategies chapter Section 7.7.8.3.2 to clearly identify the numerical BACT limits for the diesel-fired engines. The Department also included a bullet preceding the table to clarify that compliance with the limits will be demonstrated by maintaining records of maintenance procedures conducted in accordance with 40 C.F.R. Subparts 60 and 63, and the EU operating manuals. The Department also included a table in the beginning of the SIP Control Strategies chapter Section 7.7.8.3 titled "DEC BACT and SIP Findings Summary Table" which includes the Department's final decisions and timelines.

1b. BACT for Nitrogen Oxides (NOx)

In Section 7.7.8.3.1 of the proposed SIP document, ADEC states that "the NOx controls proposed in this section are not planned to be implemented." In the event that the U.S. Environmental Protection Agency (EPA) does not approve the precursor demonstration as justification not to require NOx controls, DU provides the following comments on the proposed NOx BACT determination and associated SIP requirements.

Doyon Utilities Comment (4):

If NOx BACT is required, the proposed BACT for the CHPP coal-fired boilers, Emissions Units 1 through 6, is selective catalytic reduction (SCR). The proposed emission limit is 0.060 pounds per million British thermal units (lb/MMBtu) averaged over three hours. The proposed SIP document and supporting proposed BACT Determination do not provide engineering design data supporting this emission limit for these boilers. How did ADEC determine that this emission limit was appropriate? The calculation of the emission limit is based on a 90 percent reduction in NOx emissions compared to the baseline. A 90 percent reduction is the typical maximum reduction that can be expected from the use of SCR. However, no specific engineering information is presented to support the conclusion that a 90 percent NOx emission reduction is achievable for the DU CHPP boilers, particularly in light of the economic analysis discrepancies, addressed below.

<u>Response:</u>

The Department did not revise the proposed NOx BACT limit for EUs 1 through 6 because it finds that 0.060 lb/MMBtu is an achievable limit for coal-fired boilers equipped with an SCR control system. As indicated in Chapter 2 of the June 2019 edition of EPA's Cost Control Manual for SCR: [1]

> *"Theoretically, SCR systems can be designed for NOx removal efficiencies up close to 100 percent. In practice, commercial coal-, oil-, and natural gas–fired SCR systems are often designed to meet control targets of over 90 percent. However, the reduction may be less than 90 percent when SCR follows other NOx controls such as LNB or FGR that achieve relatively low emissions on their own. The outlet concentration from SCR on a utility boiler is rarely less than 0.04 lb/million British thermal units (MMBtu)."*

The Department is unable to provide detailed engineering design data supporting the proposed NOx emission limit in the absence of site-specific vendor quotes for each NOx control technology. As indicated in the Department's September 10, 2018 request for additional information, "the cost analyses must be based on emission unit-specific quotes for capital equipment purchase and installation costs at Fort Wainwright." Without this information, a reasonable estimation of an achievable BACT limit must be used.

As indicated in Footnote 7 of the BACT Determination for Fort Wainwright, the 0.060 lb/MMBtu emission limit was calculated using the emission factor from AP-42 Table 1.1-3 for spreader stoker, sub-bituminous coal (8.8 lb NOx/ton) and converted to lb/MMBtu using the typical gross as received heat value for Usibelli Coal[2] *of 7,560 Btu/lb, assuming a 90 percent control efficiency for SCR.*

$$\left(\frac{8.8\ lb_{NOx}}{ton_{coal}}\right) \times \left(\frac{ton_{coal}}{2000\ lb_{coal}}\right) \times \left(\frac{lb_{coal}}{7560\ Btu}\right) \times \left(\frac{10^6 Btu}{MMBtu}\right) \times \left(\frac{100\% - 90\%}{100\%}\right) = \left(\frac{0.058\ lb_{NOx}}{MMBtu}\right)$$

However, as noted in the newly inserted BACT and SIP findings summary table in the SIP Control Strategies chapter Section 7.7.8.3, the Department is not requiring NOx controls for Fort Wainwright assuming the precursor demonstration is approved by the EPA.

<u>Doyon Utilities Comment (5):</u>

The economic analysis spreadsheet[3] is a cost model offered to support the SCR BACT determination. The cost model was developed by Sargent & Lundy (S&L) but does not appear to be an appropriate model for costs pertaining to the DU CHPP boilers. Additionally, the inputs to the cost model may not be appropriate or adequate to properly determine costs.

DU reviewed the cost effectiveness model and supporting documentation. The validity of the model cannot be confirmed based on the information that ADEC made available in the public

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[1] https://www.epa.gov/sites/production/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf
[2] http://www.usibelli.com/coal/data-sheet
[3] 2019-05-10-adec-calculated-scr-economic-analysis-for-wainwright.xlsm

record. From what is available in the public record, DU can note three assumptions in the model that do not look appropriate as applied to DU.

- ADEC assumed that the model is valid for a plant the size of DU's CHPP.

  The S&L SCR Cost Development Methodology[4] white paper dated January 2017 addresses several caveats which are not identified or addressed in the draft BACT Determination. The white paper states that "the costs for retrofitting a plant smaller than 100 megawatts (MW) increase rapidly due to the economy of size. S&L is not aware of any SCR installations in recent years for smaller than 100-MW units." The draft BACT Determination does not appear to adjust for the expected increased costs for retrofitting smaller plants such as the DU CHPP. DU's CHPP boilers each have a maximum heat input rate of 250 MMBtu/hr which is an equivalent maximum input of approximately 75 MW. The DU CHPP boilers have an output significantly less than 100 MW. As a result, as noted in the S&L white paper, the cost model should have been adjusted for size; because the adjustment was not made, the cost model would underestimate emissions control costs for EUs 1 through 6.

  The S&L white paper states that older units typically have limited space in which to add an SCR reactor and associated ductwork, and that the existing fans may not be sufficient to overcome the added pressure drop. The proposed BACT determination does not discuss these concerns. Whether the cost model as applied by ADEC accounts for these issues is unclear. DU readily confirms there would be significant design confirms for physical space and fan capacity if the boilers were to be retrofitted with SCR.

- The proposed BACT Determination assumes that multiple boilers can accurately be modeled using a totaled heat input in a single spreadsheet.

  The S&L white paper states that "a combined SCR for small units is not a feasible option." Each boiler requires a single, dedicated SCR reactor due to the needed heat recovery.

  Review of the spreadsheet provided by ADEC, reflects the proposed BACT considers EUs 1 thorough 6 as a single, lumped heat input value. This approach is an oversimplification and will not accurately account for the equipment and utilities necessary to independently operate six boilers. The actual installation will require six separate trains of reagent processing and transport equipment. Each train contains a various feeders, blowers, coolers, hoppers, piping, instrumentation, controls, electrical wiring and other supporting equipment. This need for separate systems complicates the design, increases overall footprint, and reduces the economy of scale that might be realized with a single larger unit.

- ADEC assumed that the model is valid for a heat and power plant.

  No information is available addressing the type of plant on which the S&L spreadsheet is based. It appears S&L assumed that the plant is a single power generation unit. However, a combined heat and power (CHP) plant differs significantly from a "traditional" power plant in that the steam produced in a CHP plant is not exclusively used to generate electricity. DU is unable to confirm that the direct annual costs can be accurately modeled for an installation such as the DU's EUs 1

[4] https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-3_scr_cost_development_methodology.pdf

through 6 by using the S&L spreadsheet.

Response:

The Department did not use the cost model developed by Sargent and Lundy for estimating SCR costs pertaining to the CHPP boilers. Rather, it used EPA's 2016 SCR Cost Manual Spreadsheet.[5] *As indicated in the Read Me tab of this spreadsheet, it can be used to estimate capital and annualized costs for applying SCR to coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour. As indicated in DU's comment, "CHPP boilers each have a maximum heat input rate of* ***250 MMBtu/hr*** *which is an equivalent maximum input of approximately 75 MW" (emphasis added). Therefore, absent a detailed engineering study and cost quotations from system suppliers, the Department finds this spreadsheet to be the most appropriate approach for estimating the cost effectiveness for implementing SCR control on the boilers. Regarding the type of plant for which the spreadsheet is based (traditional vs. combined heat and power), "the size and costs of the SCR are based primarily on five parameters: the boiler size or heat input, the type of fuel burned, the required level of NOx reduction, reagent consumption rate, and catalyst costs."* [5]

The Department acknowledges that the methodology of calculating SCR cost effectiveness using one combined heat input for the six coal-fired boilers (with six individual exhaust stacks) may result in an underestimate of the actual costs due to an economy of scale. Therefore, the Department recalculated the cost effectiveness for installing SCR on each 230 MMBtu/hr boiler using a baseline emission rate of 0.58 lb NOx/MMBtu, a difficult retrofit factor of 1.5 (the EPA spreadsheet has a retrofit factor difficulty ranging from 0.8 to 1.5), a NOx removal efficiency of 90%, an interest rate of 5.0% (current bank prime interest rate), and a 20 year equipment life. The resulting cost effectiveness value for installation of SCR NOx controls is $7,214 per ton of NOx removed. For additional information see the Fort Wainwright SCR Economic Analysis Spreadsheet in Appendix III.D.7.07 to the Control Strategies Chapter on the Fairbanks Serious SIP website at http://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-serious-sip/.

Doyon Utilities Comment (6):

Section 3.3 in the proposed BACT Determination for large diesel-fired engines, specifically Step 5(c), states that non-emergency operation of EU 8 is limited to "no more than 100 hours per year for maintenance checks and readiness testing." This requirement is inconsistent with Title V Permit AQ1121TVP02, Revision 2 which allows EU 8 to be converted to a non-emergency engine with a limit of 500 hours per year. (Please refer to Conditions 24.3 through 24.6 of that permit). Please revise this requirement to clarify that the limit applies only while the engine is classified as an emergency engine, and that the limit is not inconsistent with applicable requirements under 40 Code of Federal Regulations (CFR) 60 Subpart IIII, which allows 100 hours per year of non-emergency operation but does not restrict those non-emergency operations to maintenance checks and readiness testing. (Please refer to Condition 23.3c of Permit AQ1121TVP02, Revision 2 and 40 CFR 60.4211(f)(3).) Please align the BACT

[5] https://www3.epa.gov/ttn/ecas/docs/scr_cost_manual_spreadsheet_2016_vf.xlsm

requirements to be consistent with the existing applicable permit requirements and ensure that Section 7.7.8.3.1 of the proposed SIP document is revised for consistency with the underlying proposed BACT Determination.

Response:

The Department revised the limited operational requirement for EU 8 in Section 3.3 of the BACT Determination and Section 7.7.8.3.1 of the SIP Control Strategies chapter to clarify that EU 8 has the option to be converted to a non-emergency engine with a 500 hour per year limit, per Operating Permit AQ1121TVP02 Rev. 2.

Doyon Utilities Comment (7):

Please include a statement in Section 3.3 of the proposed BACT Determination and Section 7.7.8.3.1 of the proposed SIP document to clarify that EU 8 shall demonstrate compliance with the numerical BACT emission limit by complying with the applicable NOx emission standard in 40 CFR 60 Subpart IIII.

Response:

The Department revised Section 3.3 of the proposed BACT Determination and Section 7.7.8.3.1 of the proposed SIP Control Strategies chapter to clarify that "for the engines subject to 40 C.F.R. 60 Subpart IIII, demonstrate compliance with the numerical BACT emission limits by complying with the applicable NOx emission standards in 40 C.F.R. 60 Subpart IIII."

Doyon Utilities Comment (8):

Section 3.4 in the proposed BACT Determination for small diesel-fired engines, specifically Step 5(a), states that non-emergency operation of the small emergency engines is limited to "no more than 100 hours per year for maintenance checks and readiness testing." Please revise this requirement to clarify that the limit is not inconsistent with applicable requirements under 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ, which allow 100 hours per year of non-emergency operation but does not restrict those non-emergency operations to maintenance checks and readiness testing. (Please refer to Conditions 23.3c and 30.3 of Permit AQ1121TVP02, Revision 2, 40 CFR 60.4211(f)(3), and 40 CFR 63.6640(f).) Please align the BACT requirements to be consistent with the existing applicable permit requirements and ensure that Section 7.7.8.3.1 of the proposed SIP document is revised for consistency with the underlying proposed BACT Determination.

Response:

The Department revised Section 3.4 of the BACT Determination and Section 7.7.8.3.1 of the SIP Control Strategies chapter to clarify that the 100 hours per year limit is for non-emergency operations.

Doyon Utilities Comment (9):

Section 7.7.8.3.1 of the proposed SIP document states that BACT for NOx emissions from the small diesel-fired engines includes the requirement that "for engines manufactured after the applicability dates of 40 CFR 60 Subpart IIII, comply with the applicable NOx emissions factors in 40 CFR 60 Subpart IIII." DU believes that ADEC intended to require that the engines subject to 40 CFR 60 Subpart IIII shall comply with the applicable NOx emission standard in that rule.

Response:

The Department changed the word "factors" to "standards" to clarify the intent of the requirement.

Doyon Utilities Comment (10):

Table 3-11 of the proposed BACT Determination indicates that all of the small diesel-fired engines are subject to a numerical NOx emission limit. Section 7.7.8.3.1 of the proposed SIP document does not provide numerical emission limits for those engines not subject to 40 CFR 60 Subpart IIII. Please ensure that the underlying proposed BACT determination and the proposed SIP document are consistent to minimize possible confusion, and that the documents clearly state the compliance demonstration method.

Response:

The Department added Table 3-11 from the proposed BACT Determination Appendix into Section 7.7.8.3.1 of the SIP Control Strategies chapter to clarify the NOx emission limits for the small diesel-fired engines.

1c. BACT for Fine Fraction Respirable Particulate Matter (PM-2.5)

Doyon Utilities Comment (11):

Section 7.7.8.3.2 of the proposed SIP document and Section 4.1 of the proposed BACT Determination establish a PM-2.5 emission limit for EUs 1 through 6 of 0.006 pounds per million British thermal units (lb/MMBtu). ADEC has not provided a sound rationale for this determination and the PM-2.5 BACT emission limit. DU does not have PM-2.5 source test data for these boilers and is concerned that this limit may be unreasonably low, restrictive, and not achievable as a practical matter.

- **The basis for this limit is a source test for a different air pollutant.** The PM-2.5 BACT limit of 0.006 lb/MMBtu is based on one source test run from a three-run test conducted on EU 1 at Fort Wainwright in April 2017. This source test was an EPA Method 5 test, which measures filterable particulate matter (PM). PM includes all filterable particulate matter regardless of size. PM-2.5 includes filterable particulate matter with a nominal aerodynamic diameter of 2.5 microns or less. PM-2.5 also includes all condensable matter while PM does not include any condensable matter. The proposed BACT Determination states that the lowest PM-2.5 emission rate listed in the RBLC (RACT BACT LAER Clearinghouse database) is 0.012 lb/MMBtu. The BACT emission limit being imposed is an order of magnitude less than the lowest emission rate cited in the RBLC. No rationale or supporting engineering data are provided to justify this low emission limit, or to explain the reasons ADEC believes the limit is achievable.

- **The basis for this limit is one source test run on one boiler.** Relying on one run from one source test is an inappropriate method to establish an emission limit for any purpose. While DU appreciates that ADEC was attempting to select the worst-case run, using data from one run instead of the source test result is not appropriate or standard practice.

- If ADEC wished to rely on source testing to establish PM-2.5 limits for the coal-fired boilers, ADEC should have conducted or requested source testing for PM-2.5 emissions while adequate time was available to do so. Neither Section 7.7 of the proposed SIP document nor the underlying proposed BACT Determination explain the reasons the PM source test result is representative of the PM-2.5 emission rate. If the assumption is being made that PM-2.5 emissions from EUs 1 through 6 are less than or equal to PM emissions, this assumption should be supported (with source test results) to confirm that compliance with the limit can be achieved. Otherwise, please explain the rationale for selecting a PM-2.5 emission rate of 0.006 lb/MMBtu as the PM-2.5 BACT emission limit for EUs 1 through 6.

- In comments dated May 23, 2018, DU noted that the appropriateness of using a filterable PM emission limit to establish a PM-2.5 BACT limit had not been established. These comments were submitted to address the preliminary BACT Determination issued by ADEC in March 2018. ADEC does not appear to have considered this information in reaching the BACT determination. DU is requesting clarification from ADEC regarding whether the previously submitted information listed below was included in the BACT evaluation. If yes, DU is requesting clarification with respect how the information was considered. If no, DU is requesting clarification with respect to the reasons the information was not considered.

- During review of these proposed SIP elements, DU reviewed a spreadsheet file “Fbks_PtSrcs_2013-2019_Episode_Inventories_ToSLR.xlsm,” described by Trinity Consultants as “A version of our comprehensive point source episodic EI calculation spreadsheet with 2013- 2019 EI data. This spreadsheet references facility specific spreadsheets with hourly episodic emission or fuel/throughput rates from the original 2008 episodes.” In that spreadsheet, DU noted that ADEC and Trinity appeared to use a PM-2.5 emission factor of 0.697 pounds per ton of coal (lb/ton) to calculate PM-2.5 emissions from EUs 1 through 6 in certain tables. DU calculated this emission factor from data in Tables 1.1-5 and 1.1-6 in AP-42. The emission factor has been used to calculate potential assessable PM-2.5 emissions for EUs 1 through 6 in the two most recent Title V permit renewal applications (submitted in May 2013 and April 2019). The spreadsheet also includes tabs that show much lower PM-2.5 emission rates. DU is requesting clarification regarding the method used to calculate those lower rates and which emissions factors were used. BACT limits must be achievable in practice. As a result, DU requests that ADEC revisit the PM-2.5 BACT analysis using the appropriate available information to establish a PM-2.5 BACT limit that is well-supported with respect to being technically and economically feasible as well as achievable as a practical matter.

- The proposed SIP includes PM2.5 emission limits for EUs 7a, 7b, 7c, 51a, 51b and requires each EU to be source tested to demonstrate compliance. EUs 7a and 7c have been source tested previously but certain modification to the test method were needed due to space constraints. DU does not know whether the configurations of EUs 51 and 51b are conducive to conducting a PM2.5 source test.

Response:

The Department revised the PM-2.5 BACT limit for the coal-fired boilers from 0.006 lb/MMBtu to 0.045 lb/MMBtu to more accurately represent the particulate emissions by including both condensable and filterable particulate matter. The Department calculated this numerical limit using the baghouse controlled emissions factors from AP-42 Tables 1.1-5 and 1.1-6 for spreader stoker boilers, as follows:

$$\left(\frac{0.04\ lb_{PM\ Total\ Condensable}}{MMBtu}\right) + \left[\left(\frac{0.01 * A\ lb_{PM-2.5\ Filterable}}{ton_{coal}}\right) \times \left(\frac{ton_{coal}}{2000\ lb_{coal}}\right) \times \left(\frac{lb_{coal}}{7560\ Btu}\right) \times \left(\frac{10^6\ Btu}{MMBtu}\right)\right] = 0.045\ lb/MMBtu$$

A = 7% Ash Content [6]

7560 Btu/lb coal [6]

The Department notes that 0.045 lb/MMBtu converts to 0.680 lb/ton of Usibelli coal. This is consistent with the equations used to calculate the PM-2.5 emission factors in the two most recent Title V permit applications, using the typical gross as received heat value of 7,560 Btu/lb and an ash content of 7% for Usibelli coal.

The Department revised the compliance method for the material handling units (EUs 7a, 7b, 7c, 51a, and 51b) from conducting a source test to demonstrating compliance by following the fugitive dust control plan and the manufacturer's operating and maintenance procedures at all times of operation.

Doyon Utilities Comments (12 and 13):

Section 4.3 in the proposed BACT Determination has an inconsistent rationale for the BACT requirement to combust ultra-low sulfur diesel (ULSD) in large diesel-fired engines. (Specifically, this comment addresses privatized EU 8, the backup generator engine at the CHPP.)

- In Step 1(d), the use of low sulfur fuel is listed as an available and feasible emission control technology.

[6] http://usibelli.com/coal/data-sheet

- Step 2 states that all control technologies identified are technically feasible to control particulate emissions from large diesel-fired engines. DU notes that the use of low sulfur fuel is technically feasible, but the contribution of this technology toward reducing PM-2.5 emissions cannot be quantified.
- Step 3 does not address the use of ULSD.
- Step 5(d) requires the use of ULSD, with no supporting rationale or cost analysis.

Please make appropriate revisions to Section 4.3. DU understands that the requirement to combust ULSD will likely remain unchanged for the large diesel-fired engine. Specifically, the sulfur dioxide (SO_2) BACT decision also requires the use of ULSD, so correcting this inconsistency in Section 4.3 will not eliminate the requirement to combust ULSD in the large diesel-fired engine. The combustion of ULSD is required in the large diesel-fired engines that are subject to 40 CFR 60 Subpart IIII.

Section 4.3 in the proposed BACT Determination does not provide a cost analysis to support the proposed PM-2.5 BACT determinations identified in Step 5 for large diesel-fired engines. Because each BACT determination must be based on technical and economic feasibility, the rationale for these proposed BACT determinations is incomplete, making the validity of the determinations questionable. Please include the required economic feasibility analysis.

Response:

The Department's rationale for selecting ULSD as one of the PM-2.5 control requirements for privatized EU 8 is that it was proposed by the Army to control SO_2 emissions, and will also control PM-2.5 emissions. Because the most effective PM-2.5 control technology was selected (limited operation), a cost analysis is not required to be performed. Additionally, the Department agrees that Subpart IIII (federal emissions standards) requires EU 8 to combust ULSD and therefore constitutes a baseline emission rate (i.e., BACT floor). Therefore, ULSD must be included as a PM-2.5 control technology and no substantive changes to Section 4.3 were made.

Doyon Utilities Comment (14):

Please include a statement in Section 4.3 of the proposed BACT Determination and Section 7.7.8.3.2 of the proposed SIP document to clarify that EU 8 shall demonstrate compliance with the numerical BACT emission limit by complying with the applicable PM emission standard in 40 CFR 60 Subpart IIII.

Response:

The Department did not change Section 4.3 of the BACT Determination or Section 7.7.8.3.2 of the SIP Control Strategies chapter. Step 5(f) of Section 4.3 of the BACT Determination requires the EUs to comply with the numerical BACT emission limits listed in Table 4.6 which specifies complying with the federal emission standards in 40 C.F.R. 60 Subpart IIII.

Doyon Utilities Comment (15):

Section 4.3 in the proposed BACT Determination for large diesel-fired engines, specifically Step 5(c), states that non-emergency operation of EU 8 is limited to "no more than 100 hours per year for maintenance checks and readiness testing." This requirement is inconsistent with Title V Permit AQ1121TVP02, Revision 2 which allows EU 8 to be converted to a non-emergency engine with a limit of 500 hours per year. (Please refer to Conditions 24.3 through 24.6 of that permit). Please revise this requirement to clarify that the limit applies only while the engine is classified as an emergency engine, and that the limit is not inconsistent with applicable requirements under 40 CFR 60 Subpart IIII, which allows 100 hours per year of non-emergency operation but does not restrict those non-emergency operations to maintenance checks and readiness testing. (Please refer to Condition 23.3c of AQ1121TVP02, Revision 2 and 40 CFR 60.4211(f)(3).) Please align the BACT requirements to be consistent with the existing applicable permit requirements and ensure that Section 7.7.8.3.2 of the proposed SIP document is revised for consistency with the underlying proposed BACT Determination.

Response:

The Department revised the limited operational requirement for EU 8 in Section 4.3 of the BACT Determination and Section 7.7.8.3.2 of the SIP Control Strategies chapter to clarify that EU 8 has the option to be converted to a non-emergency engine with a 500 hour per year limit, per Operating Permit AQ1121TVP02 Rev. 2.

Doyon Utilities Comment (16):

Table 4-9 in Section 4.4 of the proposed BACT Determination includes a PM-2.5 BACT limit of 0.03 grams per kilowatt-hour (g/kW-hr) for EUs 29a and 31a. This limit appears to reflect the EPA Tier 4 final PM emission standard. EUs 29a and 31a are both certified to EPA Tier 4 interim standards. The applicable Tier 4 interim PM standard is 0.3 g/kW-hr. Please revise Table 4-9 to reflect the appropriate emission limit for these Tier 4 interim-certified engines.

Response:

The Department revised Section 4.4 of the BACT Determination to correct the BACT emissions limit to 0.3 g/kW-hr to reflect the appropriate EPA Tier 4 interim PM emissions standard. The Department also made this change in the BACT Determination summary Table 6.2.

Doyon Utilities Comment (17):

Section 4.4 in the proposed BACT Determination for small diesel-fired engines, specifically Step 5(b), states that non-emergency operation of the small emergency engines is limited to "no more than 100 hours per year for maintenance checks and readiness testing." Please revise this requirement to clarify that the limit is not inconsistent with applicable requirements under 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ, which allow 100 hours per year of non-emergency operation but does not restrict those non-emergency operations to maintenance checks and readiness testing. (Please refer to Conditions 23.3c and 30.3 of AQ1121TVP02, Revision 2, 40 CFR 60.4211(f)(3), and 40 CFR 63.6640(f).) Please align the BACT requirements to be consistent with the existing applicable permit requirements and ensure that Section 7.7.8.3.2 of the proposed SIP document is revised for consistency with the underlying proposed BACT Determination.

Response:

The Department revised Section 4.4 of the BACT Determination and Section 7.7.8.3.2 of the SIP Chapter to clarify that the 100 hours per year limit is for non-emergency operations.

Doyon Utilities Comment (18):

Section 4.4 in the proposed BACT Determination has an inconsistent rationale for the BACT requirement to combust ultra-low sulfur diesel (ULSD) in small diesel-fired engines.

- Step 1 does not identify the use of low sulfur fuel or ULSD an available emission control technology.
- Step 3 ranks low sulfur fuel in the list of technically feasible control technologies. The use of low sulfur fuel is technically feasible, but the contribution of this technology toward reducing PM-2.5 emissions cannot be quantified.
- Step 5(a) requires the use of ULSD, with no supporting rationale or cost analysis.

Please make appropriate revisions to Section 4.4. DU understands that the requirement to combust ULSD will likely remain unchanged for the small diesel-fired engines. Specifically, the SO_2 BACT decision also requires the use of ULSD, so correcting this inconsistency in Section 4.4 will not eliminate the requirement to combust ULSD in the small diesel-fired engines.

Response:

The Department revised Section 4.4 to identify low ash/sulfur fuel as a control technology. Residual fuels and crude oil are known to contain ash forming components and primary sulfates, which are particulates. Therefore, the Department considers low ash/sulfur fuel a technically feasible particulate matter control technology (i.e., clean fuel).

Doyon Utilities Comment (19):

Section 4.4 in the proposed BACT Determination does not provide a cost analysis to support the proposed PM-2.5 BACT determinations identified in Step 5 for small diesel-fired engines. Because each BACT determination must be based on technical and economic feasibility, the rationale for these proposed BACT determinations is incomplete, making the validity of the determinations questionable. Please include the required economic feasibility analysis.

Response:

The Department revised Section 4.4 to identify limited operation as a technically feasible control technology and to clarify that the Army proposed limiting the operation of the engines to 500 hours per year (94% control). Additionally, ULSD was proposed by the Army to control SO_2 emissions, and will also control PM-2.5 emissions. Because limited operation combined with ULSD was proposed by the Army, and is the most effective PM-2.5 control technology, a cost analysis is not required to be performed.

Doyon Utilities Comment (20):

Section 7.7.8.3.2 of the proposed SIP document states that BACT for PM-2.5 emissions from the small diesel-fired engines includes the requirement that "for engines manufactured after the applicability dates of 40 CFR 60 Subpart IIII, comply with the applicable PM-2.5 emissions factors in 40 CFR 60 Subpart IIII." DU believes that ADEC intended to require that the engines subject to 40 CFR 60 Subpart IIII shall comply with the applicable PM emission standard in that rule. (The rule does not include PM-2.5 emission standards.)

Response:

The Department changed "PM-2.5" to "particulate matter" to clarify the applicable emission standards in 40 C.F.R. Subpart IIII.

Doyon Utilities Comment (21):

Table 4-9 of the proposed BACT Determination indicates that all of the small diesel-fired engines are subject to a numerical PM-2.5 emission limit. Section 7.7.8.3.2 of the proposed SIP document does not provide numerical emission limits for those engines not subject to 40 CFR 60 Subpart IIII. Please ensure that the underlying proposed BACT determination and the proposed SIP document are consistent to minimize possible confusion, and that the documents clearly state the compliance demonstration method.

Response:

The Department included Table 4-9 from the BACT Determination into the Control Strategies Section 7.7.8.3.2 to clearly identify the numerical BACT limits for the diesel-fired engines. The Department also included a bullet preceding the table to clarify that compliance with the limits will be demonstrated by maintaining records of maintenance procedures conducted in accordance with 40 C.F.R. Subparts 60 and 63, and by following the EU operating manuals.

1d. BACT for Sulfur Dioxide (SO_2)

Doyon Utilities Comment (22):

In Section 5.1 of the proposed BACT Determination, Table 5.3 specifies SO_2 cost effectiveness for wet scrubbing and spray dry absorbers to be $20,673 per ton SO_2 removed and $21,211 per ton SO_2 removed, respectively. Although not explicitly stated, the proposed BACT

Determination implies that these two technologies are not economically feasible and so are not SO_2 BACT. While DU has not evaluated the cost estimates for these control technologies, DU agrees that wet scrubbing and spray dry absorbers are not SO_2 BACT. As a result, comments addressing wet scrubbing or spray dry absorbers are not presented in this document.

The preliminary proposed SO_2 BACT is dry sorbent injection (DSI) which the proposed BACT Determination states at a capital cost of $14.5 million has a cost effectiveness of $10,329 per ton SO_2 removed. DU is concerned that the analysis is based on unsupported assumptions and use of a cost model that may not be appropriate for the size of the boilers.

As a result, DU contracted with Black and Veatch (B&V) to prepare a rough-order-of-magnitude cost estimate for a DSI system to be installed at DU's CHPP six boilers. B&V was selected not only because of their experience performing engineering services on projects in Alaska for electric utilities and the US military, but the fact that they are familiar with the CHPP as a result of a 2017/2018 Heat and Energy Study.

B&V used 0.25% coal sulfur content, assumed a building enclosure for all pieces of equipment, including the silos due to the cold Fairbanks temperatures, and developed capital costs for two different types of sorbent. Trona capital costs are less expensive than sodium bicarbonate, but ongoing operation costs are higher due to the higher sorbent injection rate and cost of sorbent delivery to Fairbanks. With the addition of owner costs, DU estimates that depending on the selected sorbent selection, initial capital costs can range between $26.1 and $31.6 million. This far exceeds ADEC's estimate of $14.5 million. DU's estimate is twice the ADEC cost estimate, and believes that SO_2 controls are not economic feasible.

In addition to the B&V analysis, DU provides the following comments on the SIP DSI analysis;

- Cost Model Validity: The economic analysis spreadsheet[7] containing the cost-effectiveness calculations for the proposed SO_2 BACT determination was originally developed by Sargent & Lundy (S&L) in 2010. The spreadsheet includes a link to the S&L white paper that provides a basis for the calculations that are in Row 25 of the spreadsheet. The S&L white paper states that the model is intended to calculate estimated Total Project Cost (total capital cost of installation), as well as direct and indirect annual operating costs. These calculations are largely based on the estimated usage of sorbent (in this case Trona) on a tons per hour (tph) basis and the gross generating capacity of the plant. The white paper omits information that is necessary to ensure that the spreadsheet is properly applied to a specific situation, including:
    - Types of plants to which the model is applicable (utility power generation, combined heat and power (CHP), cogeneration, other);
    - Applicable number of boilers (single unit or multi-boiler installation);
    - Applicable size range;
    - Equipment included in the Total Purchased Cost (TPC) calculation;
    - On-site bulk storage capacity;
    - A basis for selecting a "Retrofit factor" other than "1.0"; and
    - Data and other information used to develop and support the equations used in the

[7] 2019-05-10-adec-calculated-so2-economic-analysis-fort-wainwright-locked.xlsx

spreadsheet.

Based on review of the cost effectiveness model and the supporting documentation, determining the validity of the results of the analysis is not possible given the information that ADEC has made available in the public record. The concerns are rooted in three assumptions made by ADEC in preparing the cost model.

- ADEC assumed that the model is valid for a plant the size of DU's Wainwright CHPP.
  - The calculation for "Base Module" cost (Row 30 of the spreadsheet) is based on an equation that uses the predicted sorbent demand. The S&L white paper states that the equation was developed based on "Cost data for several DSI systems." No references or supporting information relating to these projects were provided. While the validity range for the equation was not identified, one piece of information gives some indication of the applicable range. Specifically, the equation has a discontinuity at 25 tph of sorbent flow. Given that the predicted total sorbent flow for all six coal-fired boilers at DU's Wainwright CHPP is 1.5 tph, these boilers would be at the very bottom of the range of potential plant sizes. Without additional data to justify the cost calculation at very low sorbent injection rates, determining if the results of the equation are accurate is very difficult.
- The Preliminary Determination assumes that multiple boilers can accurately be modeled as a lumped heat input in a single spreadsheet.
  - The S&L white paper does not identify the type or configuration of the plant on which the calculation was based. Data input fields included in the spreadsheet (unit size, gross heat rate) indicate that the analysis was developed based on a single power generation unit (single boiler, single steam turbine, no CHP or cogeneration).
  - Based on the inputs to the spreadsheet provided by ADEC, EUs 1 thorough 6 are being treated as a single, lumped heat input value. This approach is an oversimplification and will not accurately account for the equipment and utilities that will be necessary to independently operate six boilers. The actual installation will require six separate trains of sorbent processing and transport equipment. Each train contains a day bin, mills, feeders, blowers, coolers, hoppers, piping, instrumentation, controls, electrical wiring and other supporting equipment. This need for separate systems complicates the design, increases overall footprint, and reduces the economy of scale that might be realized with a single larger unit. DU notes that the Retrofit Factor reflects a difficult retrofit in an attempt to account for this additional complexity.
  - DU also notes that adjusting the analysis to reflect the retrofit of one CHPP boiler (operated at full-load for 8,760 hr/yr) results in a cost-effectiveness value of greater than $35,000 per ton of SO_2 removed. That cost-effectiveness value is significantly greater than the $10,329 per ton removed presented in Section 5.1, Table 5-3 of the BACT Determination (Appendix III.D.7.07, pdf page 357 of 2309). BACT analyses are typically prepared for each emissions unit at a facility. While "grouping" emissions units is not necessarily unreasonable, a BACT analysis prepared for a group of emissions units must be proper and realistic. The S&L cost model does not appear to properly capture the emission control costs for EUs 1 through 6 as a group.
  - The sorbent feed rate currently calculated for EUs 1 through 6 is very low. Should the model be revised to calculate the cost effectiveness on a per unit basis, the feed rate would be roughly one sixth of the current value. This change would further amplify

concerns about the accuracy of the TPC calculation.

- ADEC assumed that the model is valid for a heat and power plant.
    - As discussed above, no information is available addressing the type of plant on which the S&L spreadsheet is based. The assumption is that the plant is a single power generation unit. A CHP plant differs significantly from a "traditional" power plant in that the steam produced in a CHP plant is not exclusively used to generate electricity. In an effort to make the spreadsheet work for this application, ADEC used "dummy" data in the "Unit Size (Gross)" and "Gross Heat Rate" fields so that the calculated "Heat Input" field showed the maximum heat input value for EUs 1 through 6 (1,380 million British thermal units per hour (MMBtu/hr)). This approach has unintended consequences relating to the accuracy of the direct annual costs. The fixed and variable operating and maintenance (O&M) costs are evaluated on a per kilowatt and a per megawatt basis respectively. Utilizing a "dummy" gross generation number to calculate annual costs may not produce an accurate result. Based on review, no method exists to accurately model the direct annual costs for an installation such as the DU EUs 1 through 6 by using the S&L spreadsheet.
    - The average maximum hourly heat input identified in Row 15 of the spreadsheet is incorrect. The value shown reflects the maximum hourly heat input for each of the boiler. The value does not account for the permitted annual coal consumption limit. If the coal consumption limit is considered, the maximum hourly heat input is reduced to 583 MMBtu/hr averaged over a year. A reduction in hourly heat input will have an impact on the overall cost effectiveness calculation, but given the concerns with the calculation itself, identifying the specific impacts is difficult.

- SO_2 Emission Rates: The SIP uses two different SO_2 emission rates. The preliminary BACT determination states that the SO_2 emission rate used in the spreadsheet to calculate the total annualized operating costs was based on 0.2 weight percent (wt. pct.) sulfur coal and AP-42 emission factors. This approach resulted in an emission rate of 0.46 pounds of SO_2 per MMBtu (lb SO_2/MMBtu) heat input. This value is significantly different than the effective emission rate for the plant based on the PTE established in Title V Permit AQ1121TVP02, Revision 2. The effective emission rate is calculated as follows:

    Permitted PTE: 1,764 tons of SO_2
    Permitted coal consumption limit: 336,000 tpy
    Assumed coal energy content: 7,600 British thermal units per pound (Btu/lb)

    1,764 tons SO_2/yr * 1 year/336,000 tons coal * 1 lb coal/7,600 Btu * 10^6 Btu/MMBtu * 1 ton coal/2,000 lb coal * 2,000 lb SO_2/ton
    = 0.691 lb SO_2/MMBtu

- The difference between the ADEC-assumed emission rate and the effective emission rate leads to a significant discrepancy in the SO_2 cost effectiveness calculation. The ADEC spreadsheet divides the total annualized cost (determined by using the 0.46 lb/MMBtu SO_2 rate) by the SO_2 PTE (with an effective rate of 0.691 lb/MMBtu). The use of two different emission rates in this calculation results in an invalid comparison of two values that should not be compared to each other. For the result of the equation to be valid, the total annualized cost must be calculated using an SO_2 emission rate equal to the SO_2 PTE.

- Conclusion: Based on the review of the proposed SO_2 BACT determination and the associated cost effectiveness calculation, no indication could be found that the proposed BACT Determination calculation accurately reflects the actual operating conditions for EUs 1 through 6.

If a more accurate cost effectiveness is to be determined, the cost effectiveness should be recalculated using a bottom-up cost estimating approach based on actual plant conditions. These conditions would include SO_2 emission rates based on current PTE, permit constraints (where applicable and enforceable), available space, ambient conditions, and local factors such as construction logistics, labor wage rates, and local sorbent costs.

Response:

The Department acknowledges that DU is concerned that the cost analysis is based on unsupported assumptions and the use of a cost model that may not be appropriate for the size of the boilers. However, absent a detailed engineering study and cost quotations from system suppliers, any control technologies successfully implemented nationwide will be considered technologically and economically feasible. See 40 CFR 51.1010(a)(3), 81 FR 58081-85.

The Department also acknowledges that DU obtained a rough order-of-magnitude cost estimate from Black and Veatch for a DSI system to be installed at the FWA CHPP. Black and Veatch indicate in its July 22, 2019 Memorandum that retrofitting the six coal-fired boilers would require an initial capital cost of roughly $20.1 million dollars with an operating cost of approximately $2.3 million dollars per year (See Attachment A to this RTC for the Black and Veatch Estimate).

However, the Army also provided a cost estimate from Amerair Industries LLC that indicates it will design, fabricate, and supply the DSI system and all associated equipment for the price of $2.8 million dollars (See Attachment B to this RTC for the Amerair Estimate). Additionally, the Army's BACT analysis calculated a total cost of 6.2 million dollars for installation of DSI with a calculated cost of $4,500/ton to $6,000/ton SO_2 *removed, for the 80% and 50% control efficiency cases, respectively.*

Therefore, based on the two aforementioned cost estimates and this comment, the Department revised the cost effectiveness calculation for retrofitting the coal-fired boilers to include dry sorbent injection and finds the cost estimate ***does not*** *result in an adverse economic impact (emphasis added). The Department revised its assumptions to represent an increased sulfur content of the coal to 0.25% by weight, adjusted the current bank prime interest rate of 5.0%, and dropped the heat input rate to the 23 MW, which is the size of one of the six boilers at the CHPP. The new Department calculated cost per ton of* SO_2 *removed is $11,383, which is considered to be cost effective for a BACT control in the Serious non-attainment area.*

Doyon Utilities Comment (23):

In Section 5.1 of the proposed BACT Determination, the proposed requirement for the coal sulfur content to be no greater than 0.2 weight percent is not evaluated using the five-step BACT process, or even identified as an available control technology in Step 1. (All coal mined at the Usibelli Coal Mine meets the definition of "low sulfur coal," which is coal with a sulfur content of less than one percent sulfur. The low sulfur coal is considered in Step 1(d).) The current coal sulfur content is not limited beyond the State SIP SO_2 standard and the requirement to determine what the SO_2 emission concentrations would be prior to combusting coal with a sulfur content of greater than 0.4 weight percent. (Refer to Conditions 11 and 11.1 of Permit AQ1121TVP02, Revision 2.) Imposing this limit without first preparing a proper BACT analysis is not appropriate. If this requirement is to be imposed as a limit without a proper BACT analysis to justify the limit, then the limit should be used to calculate a revised baseline emission rate. The BACT analysis should then calculate any further emission reductions based on that revised baseline emission rate.

DU does not agree that the coal sulfur content assumption of less than or equal to 0.2 weight percent is appropriate. More investigation is needed to determine whether this assumption is valid and feasible. The 0.2 weight percent coal sulfur limit should be assessed through the BACT analysis process. Step 1(d) of the proposed BACT Determination acknowledges that the current contract guarantee is less than 0.4 weight percent sulfur, and that the coal typically ranges from 0.08 to 0.28 weight percent sulfur.

DU does not procure coal used in the DU CHPP, but is expected to support the Department of Defense's preference to maintain a 90 day coal stockpile in the interests of energy security for Fort Wainwright. The existing 90 day coal storage pile at the CHPP includes coal with a variety of sulfur contents because coal is added to and removed from the pile over a period of years. The sulfur content of the coal pile is not certain to be less than 0.2 weight percent throughout the pile. If the final BACT requirements specify a coal sulfur content less than that currently specified contractually between the Army and Usibelli Coal Mine, please provide a limit to require that any future deliveries of coal meet the sulfur content specification as opposed to limiting the sulfur content of all coal being combusted at the DU CHPP. The coal pile at the DU CHPP is primarily an emergency storage pile and use of that stockpiled coal should not be restricted.

The Serious SIP was silent on how the sulfur content of coal was to be reported or considered within a regulatory context. The standard operating permit condition should remain the same and that facilities continue to have available the sulfur content of each shipment of fuel.

<u>Response:</u>

The Department acknowledges that the 0.2 percent sulfur content limit wasn't included as part of the BACT determination and therefore didn't go through EPA's top-down evaluation process. Instead it was established in the Control Strategies chapter as a method to limit SO_2 emissions in a reasonable way. The Department received multiple comments requesting that this limit be revised to 0.25 percent sulfur by weight. A 0.25 percent sulfur limit meets the Department's need to ensure no backsliding occurs and therefore acquiesced to that request.

The Department is therefore requiring all coal delivered to stationary sources in the Fairbanks nonattainment area to have a gross as received sulfur content of no greater than a 0.25% by *weight. This new coal sulfur requirement will need to be incorporated into DU's air quality permit. The Department used this 0.25% by weight sulfur content to recalculate the cost effectiveness for installing SO_2 controls on the coal-fired boilers at Fort Wainwright, see the Department's response to the previous comment for more details.*

Requiring the change in sulfur content to be implemented on an as-delivered-basis will allow the coal already stockpiled at Fort Wainwright to be utilized, ensuring the Department of Defense's preference to maintain a 90 day coal stockpile in the interests of energy security.

Doyon Utilities Comment (24):

Section 5.1 of the proposed SIP document appears to present language for a possible compliance order by consent (COBC) between ADEC and FWA that would impose requirements on the DU CHPP emissions units. The document does not explain how (or whether) a COBC between ADEC and the Army would ultimately apply to DU or the DU-owned emissions units. The language in the proposed COBC does not distinguish between the entire CHPP and EUs 1-6, and addresses the additional BACT for the large diesel-fired engines or the source testing or the PM2.5 emission limits for EUs 7a, 7b, 7c, 51a, 51b and requires each EU to be source tested to demonstrate compliance.

Response:

The Department has removed all references to a possible COBC between the Department and the Army from the SIP Control Strategies chapter.

Doyon Utilities Comment (25):

Section 7.7.8.3.3 of the proposed SIP document is unclear as to whether the 0.2 weight percent sulfur limit is a BACT limit or proposed as a requirement in the COBC, or both. If the 0.2 weight percent sulfur limit is intended to be a BACT limit, a BACT analysis was not prepared for this control technology. The underlying BACT Determination does not include a BACT limit requiring the use of coal with a sulfur content less than 0.2 weight percent.

Response:

The previously proposed coal sulfur limit of 0.2 percent by weight has been increased to 0.25 percent by weight. This requirement is not a BACT requirement, but rather a requirement of the SIP. To differentiate between the BACT requirements and the final determinations required by the SIP, the Department has moved the final determinations section in the SIP's Control Strategies Chapter to the beginning of the section for each source. Fort Wainwright's requirement to limit coal deliveries to 0.25 percent by weight is now summarized in the table in Section 7.7.8.3 of the SIP Control Strategies chapter.

Doyon Utilities Comment (26):

Section 5.3 in the proposed BACT Determination for large diesel-fired engines, specifically

Step 5(d), states that non-emergency operation of EU 8 is limited to "no more than 100 hours per year for maintenance checks and readiness testing." This requirement is inconsistent with Title V Permit AQ1121TVP02, Revision 2 which allows EU 8 to be converted to a non-emergency engine with a limit of 500 hours per year. (Please refer to Conditions 24.3 through 24.6). Please revise this requirement to clarify that the limit applies only while the engine is classified as an emergency engine, and that the limit is not inconsistent with applicable requirements under 40 CFR 60 Subpart IIII, which allows 100 hours per year of non-emergency operation but does not restrict those non- emergency operations to maintenance checks and readiness testing. (Please refer to Condition 23.3c of AQ1121TVP02, Revision 2 and 40 CFR 60.4211(f)(3).) Please align the BACT requirements to be consistent with the existing applicable permit requirements and ensure that Section 7.7.8.3.3 of the proposed SIP document is revised for consistency with the underlying proposed BACT Determination.

Response:

The Department revised the limited operational requirement for EU 8 in Section 5.3 of the BACT Determination and Section 7.7.8.3.3 of the SIP Chapter to clarify that EU 8 has the option to be converted to a non-emergency engine with a 500 hour per year limit, per Operating Permit AQ1121TVP02 Rev. 2.

Doyon Utilities Comment (27):

Section 5.4 in the proposed BACT determination for small diesel-fired engines, specifically Step 5(c), requires maintaining good combustion practices. The determination that good combustion practices is BACT should be eliminated or a rationale should be provided for selecting good combustion practices in addition to the combustion of ULSD and limited operations. Per Table 5-10 in Section 5.4, good combustion practices were not determined to be SO_2 BACT for small diesel-fired engines at another stationary source. While DU follows good combustion practices as a standard practice, Step 3(c) indicates that good combustion practices are the least effective SO_2 emission control technology.

Response:

The Department is not removing good combustion practices (GCP) from Section 5.4 because it finds that it is a reasonable control technology and identified in numerous locations in both the Control Strategies chapter of the SIP, the BACT Determination, and other PSD permits approved by the Department. While not explicitly identified in the RBLC Summary Table 5-9, a search of RBLC will yield multiple results of GCP being selected as BACT for diesel fired engines. Additionally, the Department had previously selected GCP as an SO_2 BACT control for the small diesel-fired engines located at the Fairbanks Campus Power Plant (UAF) and inadvertently did not include it in Fort Wainwright's BACT Comparison Table 5-10. Table 5-10 now includes GCP, Limited Operation, and Ultra-Low Sulfur Diesel for both Fort Wainwright and UAF as SO_2 controls for small diesel-fired engines.

Doyon Utilities Comment (28):

Section 5.4 in the proposed BACT Determination for small diesel-fired engines, specifically Step 5(a), states that non-emergency operation of the small emergency engines is limited to "no more than 100 hours per year for maintenance checks and readiness testing." Please revise this requirement to clarify that the limit is not inconsistent with applicable requirements under 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ, which allow 100 hours per year of non-emergency operation but does not restrict those non-emergency operations to maintenance checks and readiness testing. (Please refer to Conditions 23.3c and 30.3 of AQ1121TVP02, Revision 2, 40 CFR 60.4211(f)(3), and 40 CFR 63.6640(f).) Please align the BACT requirements to be consistent with the existing applicable permit requirements and ensure that Section 7.7.8.3.3 of the proposed SIP document is revised for consistency with the underlying proposed BACT Determination.

Response:

The Department revised Section 5.4 of the BACT Determination and Section 7.7.8.3.3 of the SIP Chapter to clarify that the 100 hours per year limit is for non-emergency operations

2. Comments from the United States Army Garrison Alaska

U.S. Army Comment (1): Section 7.7.8.3 Fort Wainwright

Please reword the sentence: "The EUs located within the military installation at Fort Wainwright Central Heating and Power Plant (CHPP) are operated by a private utility company, Doyon Utilities, LLC. (DU) and owned by the U.S. Army Garrison Fort Wainwright (FWA)" to "EUs located within the military installation include units such as boilers and generators that are owned and operated by the U.S. Army Garrison Alaska (FWA). The FWA Central Heating and Power Plant (CHPP), also located within the installation footprint, is owned and operated by a private utility company, Doyon Utilities, LLC (DU)."

The current wording suggests that DU operates all of the emission units {EUs) located within the installation footprint, which is misleading and inaccurate. DU also owns the CHPP, not Fort Wainwright. U.S. Army Garrison Fort Wainwright is now United States Army Garrison Alaska.

Response:

The Department made a technical correction to Section 7.7.8.3 of the SIP Chapter to clarify that the EUs at the CHPP is owned and operated by Doyon Utilities, LLC.

U.S. Army Comment (2): Section 7.7.8.3 Fort Wainwright, applies throughout the section

Several emission units were transferred between DU and Fort Wainwright at the beginning of 2019. The following corrections should be made to accurately reflect EU ownership and which entity has requirements to comply with: DU EU 10 is now FWA EU 50; DU EU 11 is now FWA EU 51; DU EU 12 is now FWA EU 52; DU EU 13 is now FWA EU 53; DU EU 15 is now FWA EU 54; DU EU 16 is now FWA EU 55; DU EU 17 is now FWA EU 56; DU EU 18 is now FWA EU 57; DU EU 19 is now FWA EU 58; DU EU 20 is now FWA EU 59; DU EU 21 is now FWA EU 60; DU EU 24 is now FWA EU 61; DU EU 25 is now FWA EU 62; DU EU 26 is now FWA EU 63; DU EU 27 is now FWA EU 64; and DU EU 28 Is now FWA EU 65.

Response:

The Department revised the emissions unit inventory to reflect the transfer of the EUs from DU to the Army.

U.S. Army Comment (3): Section 7.7.8.3.1 NOx Controls for Fort Wainwright, Last Paragraph

"Limit EU 8 to 500 hours of operation per year." Please clarify which EU 8 is being referred to here: FWA EU 8 or DU EU 8?

Response:

The Department made changes to the SIP Chapter 7.7.8.3.3, and BACT Determination Section's 3.3, 4.3, and 5.3 to clarify that DU EU 8 is the diesel-fired engine with a 500 hours per year operating limit.

U.S. Army Comment (4): NOx Controls for Fort Wainwright

"Limit non-emergency operation of the 27 diesel fired boilers, with the exception of the waste-fuel boilers, to no more than 500 hours per year, for maintenance checks and readiness testing."

In reviewing this requirement, there is a misstated assumption in the Fort Wainwright Best Available Control Technologies (BACT) Analysis that states that the boilers are emergency boilers. The only emergency boilers in use on Fort Wainwright are EUs 8, 9, and 10. All other boilers in the emissions inventory are considered insignificant emission sources and are not used for emergency purposes, as they are the primary heating source at their designated building Identifier. Limiting boilers to 500 hours would affect Army readiness and create problems with maintaining mission important infrastructure during seasonally cold temperatures.

Response:

The Department revised the BACT determination and Control Strategies SIP chapter to remove the 500 hour per year limits from the small diesel-fired boilers, since these units are not emergency boilers. As described in the BACT sections, the unrestricted potential to emit for the boilers is relatively small and would not result in additional controls being cost effective.

U.S. Army Comment (5): Section 7.7.8.3.2 PM2.5 Controls for Fort Wainwright

"Limit non-emergency operation of the 27 diesel fired boilers, with the exception of the waste-fuel boilers, to no more than 500 hours per year, for maintenance checks and readiness testing."

In reviewing this requirement, there is a misstated assumption in the Fort Wainwright BACT

Analysis that states that the boilers are emergency boilers. The only emergency boilers in use on Fort Wainwright are EUs 8, 9, and 10. All other boilers in the emissions inventory are considered insignificant emission sources and are not used for emergency purposes, as they are the primary heating source at their designated building identifier. Limiting boilers to 500 hours would affect Army readiness and create problems with maintaining mission important infrastructure during seasonally cold temperatures.

Response:

The Department revised the BACT determination and Control Strategies SIP Chapter to remove the 500 hour per year limits from the small diesel-fired boilers, since these units are not emergency boilers. As described in the BACT sections, the unrestricted PTE for the boilers is relatively small and would not result in additional controls being cost effective.

U.S. Army Comment (6): Section 7.7.8.3.3 SO_2 Controls for Fort Wainwright

"Limit non-emergency operation of the 27 diesel fired boilers, with the exception of the waste-fuel boilers, to no more than 500 hours per year, for maintenance checks and readiness testing."

In reviewing this requirement, there is a misstated assumption in the Fort Wainwright BACT Analysis that states that the boilers are emergency boilers. The only emergency boilers in use on Fort Wainwright are EUs 8, 9, and 10. All other boilers in the emissions inventory are considered insignificant emission sources and are not used for emergency purposes, as they are the primary heating source at their designated building identifier. Limiting boilers to 500 hours would affect Army readiness and create problems with maintaining mission important infrastructure during seasonally cold temperatures.

Response:

The Department revised the BACT determination and Control Strategies SIP Chapter to remove the 500 hour per year limits from the small diesel-fired boilers, since these units are not emergency boilers. As described in the BACT sections, the unrestricted PTE for the boilers is relatively small and would not result in additional controls being cost effective.

U.S. Army Comment (7): Section DEC BACT DETERMINATION for Fort Wainwright Central Heating and Power Plant

Based on a review of the control package and the BACT analyses for the other two coal fired facilities located in the nonattainment area, the economic feasibility argument finding should equitably apply to all coal fired facilities in the nonattainment area. There is no articulated argument stating why the Fort Wainwright CHHP is required to have additional controls or why it is dissimilar to the other coal power plants that are subject to the same requirements. The Fort Wainwright CHHP is a coal fired plant with the same or similar processes as the Chena Power Plant and the UAF Power Plant, and would be subject to the same proposed coal sulfur limitations. Studies completed by EPA in 2016, as highlighted in Vol. II: 111.D.7.8 Modeling document, states that wood smoke contributes between 60-80% of the fine particulate matter found on filters during the winter months, while major sources contribute less than 10%. Installation of costly controls on an aging facility may that have little to no influence on the air quality in the nonattainment area, where wood smoke is identified as the major primary contributor.

Additionally, Fort Wainwright is assessing future energy usage based on aging infrastructure and is developing plans for improvement or replacement of current utilities, which has a projected timetable of less than 15 years. As such, Fort Wainwright requests that an Economic Infeasibility determination be applied to the Fort Wainwright CHHP.

Response:

Consistent with the BACT Determination for Fort Wainwright, the BACT Determinations for the Chena Power Plant and UAF Campus Power Plant identify SO_2 and NOx BACT controls for the coal fired boilers at these sources. The NOx controls proposed in these determinations are not planned to be implemented. The optional precursor demonstration (as allowed under 40 C.F.R. 51.1006) for the precursor gas NOx for point sources illustrates that NOx controls are not needed. The Department assumes EPA will approve this precursor demonstration.

Regarding the economic infeasibility finding for Chena Power Plant and UAF Campus Power Plant stated in the Control Strategies SIP chapter, these sources provided financial indicators to the Department contending that they cannot afford the control technologies demonstrated to be economically feasible in the BACT Determinations. As stated in the PM-2.5 implementation rule:

> *"If a source contends that a source specific control-level should not be established because the source cannot afford the control measure or technology that is demonstrated to be economically feasible for other sources in its source category, the source should make its claim known to the state and support the claim with information regarding the impact of imposing the identified control measure or technology on the following financial indicators, to the extent applicable:*
>
> *(1) Fixed and variable production costs ($/unit)*
>
> *(2) Product supply and demand elasticity*
>
> *(3) Product prices (cost absorption vs. cost pass-through)*
>
> *(4) Expected costs incurred by competitors*
>
> *(5) Company profits*
>
> *(6) Employment costs*
>
> *(7) Other costs (e.g., for RACM implemented by public sector entities)."*

The Department acknowledges that the majority of PM-2.5 found on the filters during high particulate matter days in the winter months are a result of wood smoke, but this does not obviate the requirement under the Clean Air Act to conduct BACT analyses on point sources that emit more than 70 tons per year of PM-2.5 or for any individual PM-2.5 precursor (NOx, SO_2, NH_3, VOCs). These sources are subject to site-specific review for BACT.

3. Comments from the United States Air Force (USAF)

USAF Comments (1 and 2):

On 14 May 2019, the Alaska Department of Environmental Conservation (ADEC) released the Serious Area State Implementation Plan (SIP) for the Fairbanks North Star Borough (FNSB) Fine Particulate (PM2.5) Nonattainment Area (NAA) for public review. Public comments are due by 5:00 p.m. on 26 July 2019. The Air Force appreciates the opportunity to comment on the SIP and the collaborative effort with the ADEC to provide a means to attain the PM2.5 24-hour standard.

Although Eielson Air Force Base in not within the NAA, Eielson shares a coal contract with Fort Wainwright Army Garrison for coal obtained from Usibelli Coal Mine (UCM). The Air Force has the following comment on the sulfur content of coal.

a) In Amendments to State Air Quality Control Plan Vol. III: Appendix III.D.7.07 and in the Best Available Control Technology (BACT) Summary Highlight located at http://dec.alaska.gov/media/16232/bact-summary-highlight-051419.pdf the proposed BACT for coal sulfur content is 0.2 percent sulfur by weight. This sulfur limit will cut off access to tens of millions of tons of coal from UCM as well as pose a potential threat of fuel supply interruption for the coal-fired power plant using UCM coal.

b) The Air Force requests ADEC adopt a BACT coal-sulfur content of 0.25 percent sulfur by weight based on a semi-annual weighted average of coal-sulfur content in shipments of coal within the semi-annual period corresponding to Facility Operating Report reporting period.

c) The ADEC has proposed that BACT for coal burning facilities in the nonattainment area is a coal-sulfur limit of 0.2 percent sulfur by weight. UCM is the only source of commercial coal available to the coal-fired boiler facilities within the Fairbanks North Star Borough fine particulate nonattainment area. The mine has limited ability to affect the sulfur content in the coal. There is not a coal washing or segregating facility associated with UCM which could ensure a consistent coal- sulfur concentration. Current practice for providing low-sulfur coal to their customers is identifying sulfur content of the resource through drilling and sampling efforts. However, the ability to characterize the sulfur content of the coal mined is limited.

   Within the millions of tons of coal resources available to UCM, there is a significant amount of coal with higher sulfur content than 0.2 percent by weight; in fact, any limit proposed to the coal sulfur content is effectively cutting off access to tens of millions of tons of coal resources. As such, the Air Force proposes that the coal-sulfur content limit be lowered to 0.25 percent by weight on an as received basis (wet) as opposed to 0.2 percent by weight as proposed by ADEC. The increase in coal sulfur content will help with coal accessibility and availability over the next decade.

> The state was silent on how the measure was to be reported or considered within a regulatory context. The ADEC's standard permit condition for coal fired boilers (Standard Condition XIII) requires that the permittee report sulfur content of each shipment of fuel with the semi-annual Facility Operating Reports. UCM currently provides a semi-annual report to all customers which includes sulfur content of each shipment of coal along with the weighted average coal-sulfur content for the six-month period coinciding with the operating reports' reporting period. The Air Force proposes that the standard operating permit condition remain the same, and that facilities continue to provide the 'State with the sulfur content of each shipment of fuel; in addition, the weighted average coal-sulfur content of the shipments received by the facility during the reporting period would be referenced in the operating report.

Response:

The Department is requiring all coal delivered to stationary sources in the Fairbanks nonattainment area to have a gross as received sulfur content of no greater than a 0.25% by weight. The sources identified in the SIP Control Strategies Chapter that use coal will be required to submit an application to apply for an air permit to include the new coal sulfur content limit. The Department is not intending to change Standard Permit Condition XIII to implement this change.

APPENDIX A: BLACK AND VEATCH COST ESTIMATE

APPENDIX B: A AMERAIR QUOTE FOR FGD

From:	Jones, Dave F (DEC)
To:	scoiley@doyonutilities.com
Cc:	ijackson@doyonutilities.com; Edwards, Alice L S (DEC); Heil, Cynthia L (DEC); James R Plosay (DEC) (jim.plosay@alaska.gov); Simpson, Aaron J (DEC)
Subject:	Fairbanks PM-2.5 Serious SIP - Information Request for B&V Cost Estimate for DSI Controls on Coal Fired Boilers
Date:	Tuesday, September 24, 2019 10:50:00 AM

Shayne,

On July 26, 2019, the Alaska Department of Environmental Conservation (Department) received comments from Doyon Utilities, LLC (DU) for the Fairbanks PM-2.5 Serious SIP. In Comment 22, DU states it received a "rough-order-of-magnitude cost estimate" from Black and Veatch (B&V) for installing a dry sorbent injection (DSI) system on the coal-fired boilers (EUs 1 through 6), located at Fort Wainwright. The comment indicates that the initial capital cost estimates, depending on the selected sorbent selection, can range from between $26.1 and $31.6 million. If DU would like the Department to consider the cost information from B&V, please provide that information to the Department no later than Friday, October 4, 2019.

Regards,

Dave Jones
Env. Engineering Assistant I
ADEC – Air Quality – Juneau
dave.jones2@alaska.gov
907.465.5122

From: Isaac Jackson
To: Heil, Cynthia L (DEC)
Cc: Jones, Dave F (DEC); Stephanie.Koessel@dla.mil; Samantha.Kimble@dla.mil; stephen.d.stringham2.civ@mail.mil; "fred.o.sandgren.civ@mail.mil"; Burgess, Diana L CIV USARMY IMCOM PACIFIC (USA); peter.marvin.civ@mail.mil; Shayne Coiley; Kathleen Hook; Edwards, Alice L S (DEC); Plosay, James R (DEC); Simpson, Aaron J (DEC)
Subject: RE: [EXTERNAL] :Fairbanks PM-2.5 Serious SIP - Information Request for B&V Cost Estimate for DSI Controls on Coal Fired Boilers [CO 19-084]
Date: Friday, October 4, 2019 4:53:01 PM
Attachments: DU FWA Additional BACT Comments 10.4.19_CO_19_084.pdf

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Attached is Doyon Utilities response to the Alaska Department of Environmental Conservation’s request for information, via email on September 24, 2019, regarding the Black and Veatch (B&V) cost estimate for installing dry sorbent injection (DSI) on the coal fired boilers located at Fort Wainwright, Alaska.

Please contact Kathleen Hook khook@doyonutilities.com or (907) 455-1540 if you have any questions.