Alaska Department of Environmental Conservation

Amendments to:

State Air Quality Control Plan

Vol. III: Appendix III.D.7.7
{Appendix to Volume II. Analysis of Problems, Control Actions; Section III. Area-wide Pollutant Control Program; D. Particulate Matter; 7. Fairbanks North Star Borough PM2.5 Control Plan, Serious Requirements}

Adopted

November 5, 2024

Michael J. Dunleavy, Governor

Emma Pokon, Commissioner

Note: This document is the Appendix to Control Strategies Chapter. The document provides the adopted language of the 2024 Amendments to Serious SIP for inclusion in the section of the State Air Quality Control Plan to address the disapproval of the Serious SIP and the 2020 Amendments. The public notice draft of the 2024 Proposed Amendments can be found and referenced at the https://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-2024-proposed-amendment-serious-sip/

(This page serves as a placeholder for two-sided copy)

Appendix III.D.7.07

Content

1. 2024 Revised Best Available Control Measures Analysis (BACM) for Fairbanks $PM_{2.5}$ Nonattainment Area.

   The following documents are included as part of the BACM analysis, however due to their electronic nature, they may be found posted separately at: https://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-proposed-amendment-serious-sip/

   BACM Cost Effectiveness Analysis – Charbroilers – Measure 68.xlsx
   BACM Cost Effectiveness Analysis – IdlingHDV – Measure 57-60-R20.xlsx
   BACM Cost Effectiveness Analysis – Revised IdlingLDV – Measure 57-60-R20.xlsx
   BACM Cost Effectiveness Analysis – Revised ULSD CE – Measure 51.xlsx
   BACM Cost Effectiveness Analysis – Used Oil Disposal – Measure 70.xlsx

2. BACT Appendix Documents

Chena Power Plant Cover Page

Contents

1. 10.21.24 Final Chena BACT Determination
2. 10.21.24 Chena Power Plant SO_2 BACT MR&R Final
3. AQ0315MSS02 Rev 1 Final Permit

The following spreadsheets are included as part of the appendix. However, due to their electronic nature, they may be found posted separately on the web page:

1. 02.23.24 Statistical Analysis for $PM_{2.5}$ Emission Limit from 2011 Source Test.xlsx
2. 31430_Aurora_DSI_Opinion_of_Probable_Cost_F.xlsx
3. AppxA&B_CPP-BACT_Tables_2024125.xlsx
4. 0327.24 Department DSI Cost Calculation.xlsx
5. 1009.23 Aurora Rail Samples for Coal.xlsx
6. 10.10.23 ADEC preliminary Estimate of Increased Load on Chena Power Plant Baghouse.xlsx

Fort Wainwright BACT Cover Page

Contents

1. 10.21.24 Final Fort Wainwright BACT Determination
2. 10.21.24 Fort Wainwright SO_2 BACT MR&R Final
3. AQ0236MSS03 Rev. 2 Final Permit

GVEA North Pole Power Plant Cover Page

Contents
1. 10.21.24 Final North Pole Power Plant BACT Determination
2. 10.21.24 North Pole Power Plant SO_2 BACT MR&R Final
3. AQ0110MSS01 Rev. 1 Final Permit

The following spreadsheets are included as part of the appendix. However, due to their electronic nature, they may be found posted separately on the web page:

1. Updated Department North Pole Plant SO_2 Controls Economic Analysis.xlsx
2. GVEA Fuel Prices.xlsx
3. AQ0110TVP04 NPP FuelPrices Provided 02.24.2021.xlsx

GVEA Zehnder BACT Cover Page

Contents
1. 10.21.24 Final Zehnder BACT Determination
2. 10.21.24 Zehnder SO_2 BACT MR&R Final
3. AQ0109MSS01 Rev. 2 Final Permit

The following spreadsheets are included as part of the appendix. However, due to their electronic nature, they may be found posted separately on the web page:

1. Updated Department Zehnder Power Plant SO_2 Controls Economic Analysis.xlsx
2. A04_FuelPrices_1810.xlsx

UAF BACT Cover Page

Contents
1. 10.21.24 Final UAF BACT Determination
2. 10.21.24 UAF SO_2 BACT MR&R Final
3. AQ0316MSS08 Rev. 1 Final Permit

The following spreadsheets are included as part of the appendix. However, due to their electronic nature, they may be found posted separately on the web page:

1. Department BACT AppxG Andritz CDS-CostEst.xlsx
2. Department BACT AppxH BACT DSI CostEst _Jan2023.xlsx
3. Department BACT AppxH BACT TriMer_DSI-CostEst_Jan2023.xlsx
4. Departments UAF_BACT AppxF EPA WFG CCM Est.xlsx
5. Updated Department Version of UAF BACT PM2.5 Tables 4-X.xlsx
6. UAF BACT AppxF EPA WFGD CCM Estimate Jan2023.xlsx
7. UAF BACT AppxG Andritz CDS CostEst Jan2023.xlsx
8. UAF BACT APPxH BACT DSI-CostEst Jan2023.xlsx
9. UAF BACT AppxH TriMer DSI-costEst Jan2023.xlsx
10. UAF BACT Report Tables Jan2023.xlsx
11. Costs Assoc W Stack Replacement or CDS Jan2023.xlsx

Control Measures Analysis for Fairbanks $PM_{2.5}$ Nonattainment Area for the 2024 Revision to the Serious State Implementation Plan

Draft

Table of Contents

List of Tables

List of Figures

1. Introduction

In November 2009, a portion of the Fairbanks North Star Borough (FNSB or Fairbanks) was designated as a Moderate nonattainment area for the 2006 24-hour Fine Particulate ($PM_{2.5}$) National Ambient Air Quality Standard (NAAQS).[1] On April 28, 2017, EPA officially re-classified the Fairbanks area from "Moderate" to "Serious" nonattainment for the 24-Hour $PM_{2.5}$ standard.[2] The design value used in the Serious SIP for the 2013-2015 period was 124 $\mu g/m^3$ (microgram per cubic meter). The difference between this value and the ambient standard is 89 $\mu g/m^3$, which means that 98th percentile concentrations (the form of the standard) needed to be reduced by 72% to demonstrate attainment. Alaska Department of Environmental Conservation (ADEC) submitted the Serious Area State Implementation Plan (SIP) for the Fairbanks $PM_{2.5}$ nonattainment area on December 13, 2019. The EPA determined the plan met the completeness criteria on February 11, 2020 (85 FR 7760).[3] Subsequently, the EPA found that the Fairbanks $PM_{2.5}$ nonattainment area failed to attain the applicable Serious area attainment date of December 31, 2019 (85 FR 54509).[4]

ADEC revised the state regulations and the State Air Quality Control Plan and submitted the 2020 amendments to the EPA on December 15, 2020, to meet the requirements of CAA Section 189(d), in addition to the requirements of CAA sections 172 and 189(b). The 2020 Amendment to the Serious SIP (2020 Amendment) has a new base year, 2019, and a lower 4-year modeling design value (64.7 $\mu g/m^3$) reflecting the progress that has been made in reducing emissions and addressing $PM_{2.5}$ air pollution over the last five years. On September 24, 2021, the EPA approved parts of the Serious SIP submissions in the Federal Register (86 FR 52997).[5] However, on January 10, 2023, the EPA published the proposed disapproval of the SIP in the Federal Register 88 FR 1454).[6] Following EPA's proposed disapproval, ADEC prepared responses to EPA's comments and reevaluated the control measures that EPA dismissed in their proposed disapproval. In the 2024 Amendments to the 189(d) Plan for the Serious SIP, ADEC revised the State regulations and control measure strategies based on EPA's comments to meet the requirements of the CAA.

The purpose of this document is to describe the process of revisions to the Control Measures for the 2024 Amendments to the Serious $PM_{2.5}$ Attainment Plan for the Fairbanks North Star Borough in Alaska.

Presented below is a review of the regulatory requirements that continue to be addressed from the 2020 Amendment in the review, analysis, and selection of measures for the 2024 Revised Amendment. Also presented is a summary of revisions made to strengthen both FNSB and Alaska Department of Environmental Conservation (DEC) $PM_{2.5}$ regulatory controls included in the Serious Area SIP. Those revisions form the baseline set of controls against which control measures adopted in other communities and agencies are examined for measure selection in the

[1] https://www.gpo.gov/fdsys/pkg/FR-2009-11-13/pdf/E9-25711.pdf
[2] https://www.federalregister.gov/documents/2017/05/10/2017-09391/determinations-of-attainment-by-the-attainment-date-determinations-of-failure-to-attain-by-the
[3] https://www.govinfo.gov/content/pkg/FR-2020-02-11/pdf/2020-00982.pdf
[4] https://www.govinfo.gov/app/details/FR-2020-09-02/2020-17541
[5] https://www.govinfo.gov/content/pkg/FR-2021-09-24/pdf/2021-20396.pdf
[6] https://www.govinfo.gov/content/pkg/FR-2023-01-10/pdf/2022-28666.pdf

2020 Amendments and their revision in the 2024 Amendment. A brief outline of the remainder of the report is also presented.

Requirements for the 2024 Amendment Analysis

The process for selecting measures for the 2024 Revised Amendment to the Serious SIP is defined in a series of steps detailed in the 2016 Final $PM_{2.5}$ Rule.[7] Those steps clarify and update PM_{10} control measure selection guidance presented in the Addendum to the General Preamble[8] for the selection of $PM_{2.5}$ controls for both Reasonably Available Control Measures (RACM), required for Moderate nonattainment areas and BACM for Serious nonattainment areas. Presented below is a summary of the selection guidance presented in the Final $PM_{2.5}$ Rule that is relevant for the 2024 Revised Amendment Plan. The guidance is defined in a series of steps specified in the BACM selection process (i.e., the same process used to select BACM in the Serious SIP, and 2020 Amendment is used to select measures for the 2024 Revised Amendment). The control measure guidance for the 2020 Amendment requires "all control measures must be quantifiable, enforceable, replicable and accountable" as described in Section VI.D.5 of CAA section 189(d).

- **Step 1: Develop a Comprehensive Inventory of Sources and Source Categories of Directly Emitted $PM_{2.5}$ and $PM_{2.5}$ Precursors** – The inventory identifies the contribution of each source category to directly emitted $PM_{2.5}$ and precursor emissions. This information is needed to understand the relative contribution and significance of each source to the overall burden on the nonattainment area. EPA requires the identification of both anthropogenic (man-made) and non-anthropogenic (natural) emissions. It also requires the analysis to start with the base year emissions inventory submitted with the Serious area attainment plan and to update it as necessary to reflect growth, construction, shutdowns, roadway improvements and other relevant changes that affect activity within the nonattainment area. EPA also requires the Step 1 inventory to be consistent with the emissions inventory requirements for Serious area plans.

- **Step 2: Identify Potential Control Measures** – Consistent with earlier guidance, the $PM_{2.5}$ Final Rule requires states to identify controls for each of the primary and secondary emission sources developed to represent activity within the subject nonattainment area. The starting point for assembling a list of controls is the BACM analysis prepared for the Serious SIP. All controls considered, but not adopted, must be identified. States are required to conduct a comprehensive review of information sources on existing and potential control measures implemented in other nonattainment areas around the country. Measures and technologies considered and implemented in attainment plans are a significant source of information. Other information sources include summaries of control measures assembled by regional planning organizations and local air quality consortiums. EPA also maintains online links to a variety of control programs. States are required to identify both existing and potential new measures for the source

[7] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf
[8] https://www3.epa.gov/ttn/naaqs/aqmguide/collection/cp2/19940816_59fr_41998-42017_addendum_general_preamble.pdf

categories identified in the base emissions inventory. The goal is to identify a list of control measures that are more stringent than those adopted in the Serious SIP.

Step 3: Determine Whether an Available Control Measure or Technology is Technologically Feasible – This step evaluates the technical complexity of implementing a control measure and involves determining if the measure can be implemented with the existing techniques and tools by taking into account the several factors such as source's operating procedures, potential impacts on the environment (e.g., air, water, noise, etc.) and energy (e.g., consumption, availability, etc.). Measures targeting area and mobile sources need to consider the local circumstances, the condition and extent of needed infrastructure, population size, workforce type and habits, etc. In addition, the critical source parameters needed to assess the impacts of the technology need to be identified (e.g., fuel specifications, travel activity, EPA certification, etc.). A key consideration is whether the identified measure provides an emissions benefit beyond those provided by existing federal, state, and local controls. As per the Final Rule, States while assessing the feasibility of a control measure for BACM, should place a higher threshold (more stringent) compared to control measure evaluation for RACM.[9] Additionally, if a control is technologically infeasible but has been implemented in another $PM_{2.5}$ nonattainment area, then the State will need to provide a detailed justification for technological infeasibility. in instances where a control measure has been implemented in another $PM_{2.5}$ nonattainment area. The final Rule also states that, unlike RACM process where the economic and technological feasibility had equal weightage in evaluating a control measure, economic feasibility is a less significant factor in BACM determination process.

- **Step 4: Determine Whether an Available Control Technology or Measure is Economically Feasible** – This step requires an explicit examination of the costs and emission benefits of the technologically feasible measure leading to an assessment of the $/ton of pollutant reduced. As per the Final Rule, the key components used in assessing the economic feasibility includes the capital, maintenance, and operating costs, and emissions reduction as a result of implementing the control measure. Factors to be considered for evaluating the economic feasibility relates to fixed and variable production costs, product supply and demand elasticity, product prices (cost absorption vs. cost pass-through), expected costs incurred by competitors, company profits, employment costs, and other costs for BACM implemented by public sector entities).[10] While the CAA section 110(a)(2)(E)[11] requires the State to provide necessary assurance of having adequate funding, personnel, and authority to implement a control measure, the requirement does not mention that the funding/costs to be borne by the State cannot be included in the economic feasibility assessment of the control measure. Similar to the technological feasibility, States need to consider control measures with a higher costs per ton in the BACM economic evaluation process compared to a RACM. In contrast to the criteria employed in the RACM determination process, economic feasibility "is a less significant factor." States "may not eliminate a particular control measure as potential

[9] 81 Fed. Reg. at 58085
[10] 81 Fed. Reg. at 58085
[11] 40 CFR 51.1010 at 407

BACM if similar sources have successfully implemented such a measure." States are also required to consider technologically feasible measures that have not been implemented by similar sources but can reduce emissions at a cost that is not prohibitive. The Final $PM_{2.5}$ Rule does not establish a specific $/ton threshold for economic feasibility but rather states that cost-effectiveness estimates provide a relative value for each emissions reduction option that is comparable with other options.[12] More expensive control measures must be adopted unless it can be demonstrated that costs and cost-effectiveness prohibitive relative to existing controls.

Step 5: Determine the Earliest Date by Which a Control Measure or Technology can be Implemented in Whole or Part – The CAA requires Serious area attainment plans to provide for the implementation of BACM no later than 4 years after reclassification of the area to Serious or prior to the statutory attainment date for the area. If a state determines that technologically and economically feasible measures can be implemented in whole or in part during this period they must be adopted and implemented as expeditiously as possible. As with the EPA's proposed approach to RACM and RACT, the EPA proposes the term ''implement'' to mean that the control measure or technology has not only been adopted into the SIP for the area but has also been built, installed and/or otherwise physically manifested and the affected sources are required to comply. Since Fairbanks was classified as non-attainment for $PM_{2.5}$ in December 2009 the statutory attainment date was December 2019. After the Fairbanks $PM_{2.5}$ Nonattainment Area failed to attain by December 31, 2019, ADEC was required to adopt the BACM by December 31, 2020.[13] Based on EPA's Final Rule[14] and the regulatory references included for BACM (40 CFR 51.1010 (C)(3)[15], 51.1004(a)(3)[16]), following the finding of failure to attain by the applicable Serious area attainment date, the state may make a demonstration that a measure identified is not technologically or economically feasible to implement in whole or in part within 5 years or such longer period as the EPA may determine is appropriate after the EPA's determination that the area failed to attain by the Serious area attainment date. This date corresponds to December 31, 2024.

Revisions to Strengthen $PM_{2.5}$ Regulatory Controls

Recognizing the need to make continued progress towards attainment, both the Borough and the state continued to evaluate and adopt regulatory controls after the submission of the Serious area SIP and the 2020 Amendments. Since these controls form the baseline against which potential 2024 Revised Amendment control measure technical and economic feasibility is assessed, a summary of the measures adopted is presented below.

[12] 81 Fed. Reg. at 58042
[13] ADEC, 2020 Amendments to the Serious SIP. Appendix III.D.7.7. Assessed at https://dec.alaska.gov/media/22038/appendix-iii-d77-control-strategies-adopted-11-18-20.pdf.
[14] 88 Fed. Reg. at 84626
[15] 40 CFR 51.1010 (C)(3). Accessed at https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-51/subpart-Z/section-51.1010
[16] 51.1004(a)(3). Accessed at https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-51/subpart-Z/section-51.1004#p-51.1004(a)(3)

Borough Ordinance Revisions

The $PM_{2.5}$ Air Quality Control Program is codified in Chapter 21.28. Numerous changes to the program were debated within the Assembly leading to the adoption of ten separate Ordinances amending the program since the submission of the Moderate Area Plan to EPA December 31, 2014, and January 29, 2015. Collectively, those changes significantly increased the coverage and authority of the program to control emissions within the nonattainment area. Passage of Proposition 4, the Home Heating Reclamation Act, on October 5, 2018, however, required the Borough to remove all of the ordinances implementing home heating restrictions, calling air quality alerts and enforcing them. The proposition is effective for a 2-year period and is set to expire October 2020, unless a new similarly structured proposition is approved by voters in the 2020 election. However, action would need to be taken by the FNSB in coordination with the state to establish or reestablish specific local authorities related to home heating. In the absence of a local control program, the Clean Air Act requires states to take responsibility for implementing air quality control programs that move the community towards attainment of the NAAQS. Since the 2020 Amendment, the only changes to the Borough Ordinance related to local air quality have been to increase the incentives offered for the change-out programs in the Nonattainment Area.

Alaska Administrate Code Revisions

With an effective date of January 8, 2020, the Serious SIP was adopted by reference in state regulation (18 AAC 50). In addition, the following sections of Chapter 50, the Air Quality Code were amended with the same effective date unless otherwise noted:

- 18 AAC 50.030 Adopted Serious SIP Chapters and Appendices (revised as of July 29, 2022)
- 18 AAC 50.055 Emission limits for industrial processes and fuel-burning equipment
- 18 AAC 50.075(e) Solid Fuel Heating Device Curtailment during air episodes and requirement to withhold fuel within three hours of effective time of a State 1 or Stage 2 Alert
- 18 AAC 50.075(f) Visible Emission requirements for solid fuel heating devices
- 18 AAC 50.076 Solid fuel-fired heating device fuel requirements; requirements for wood sellers
- 18 AAC 50.076(j) - (k) Commercial wood sellers may only sell dry wood unless exempted.
- 18 AAC 50.076(l) Non-commercial wood sellers may not sell wet wood.
- 18 AAC 50.077 Requirement to remove or replace wood-fired heating devices and wood-fired outdoor hydronic heaters Upon Sale of Property that do not meet EPA or state standards and render the device inoperable.
- 18 AAC 50.077(a) Outdoor hydronic heaters may not be sold or installed in the Nonattainment Area.

- 18 AAC 50.077(b) Emissions Standards for new pellet hydronic heaters sold or installed in the Nonattainment Area.
- 18 AAC 50.077(c) Emissions Standards for new woodstoves and pellet stoves sold or installed in the Nonattainment Area.
- 18 AAC 50.077(d) Emissions Standards for new wood-fired heating devices over 350,000 Btu/hr sold or installed in the Nonattainment Area
- 18 AAC 50.077(h) Device Registration requirements
- 18 AAC 50.077(i) - (k) Device Installation requirements
- 18 AAC 50.077(k) Vendors Requirements - wood-fired heating devices
- 18 AAC 50.077(l) Device Requirement remove non-EPA certified devices and outdoor hydronic heaters by December 31, 2024
- 18 AAC 50.077(n) Device Requirements - removal of old EPA certified devices - upon effective date of published EPA finding.
- 18 AAC 50.078(b) Only fuel oil containing no more than 1,000 parts per million (ppm) sulfur may be sold – with an effective date of September 01, 2022
- 18 AAC 50.078(c) - small area sources required to submit information
- 18 AAC 50.078(d) - Commercial coffee roasters must install a pollution control device if any unit emits more than 24 pounds (lbs) of particulate matter (PM) in a 12-month period.
- 18 AAC 50.079(b) may not install or reinstall coal-fired heating devices
- 18 AAC 50.079(c) Requirement to remove coal-fired heating devices upon sale of property unless a wintertime source test shows that it meets emission standards
- 18 AAC 50.079(f) all existing coal-fired heating devices shall be removed by December 31, 2024.

In addition to the code revisions noted above, EPA issued a Federal Register Notice[17] on September 2, 2020, finalizing its determination that Fairbanks failed to attain the ambient $PM_{2.5}$ standard by the attainment date. This finding triggered the implementation of the contingency measure included in the Serious $PM_{2.5}$ SIP. The measure that was implemented effective October 2, 2020, is 18 AAC 50.077(n), date certain removal for EPA-certified devices over 2.0 g/hr and over 25 years old. The rule requires owners of wood heaters to:

- Remove/replace all EPA-certified stoves that are 25 years or older AND have an emission rating greater than 2.0 g/hr by no later than December 31, 2024, or at the time of a property transaction (e.g. home sale, lease, conveyance) whichever is earlier.

[17] https://www.govinfo.gov/content/pkg/FR-2020-09-02/pdf/2020-17541.pdf?utm_campaign=subscription+mailing+list&utm_source=federalregister.gov&utm_medium=email

- For similarly emitting devices newer than 25 years before the effective date of the EPA finding, removal or replacement is required before 25 years from the date of manufacture.

EPA approved the contingency measure submitted as part of the Fairbanks 189(d) Plan as SIP-strengthening on September 24, 2021, (86 FR 52997). In the 2020 Amendments, ADEC identified a contingency measure to increase the stringency of the curtailment program for wood-fired heating devices, that account for a significant portion of the emissions inventory and are a critical element of the Fairbanks attainment plan. The contingency measure would lower the Stage 2 curtailment threshold from 30 to 25 $\mu g/m^3$, under the Fairbanks Emergency Episode Plan, State Air Quality Control Plan, Vol II, Chapter III.D.7.12. In the event that EPA issues any of the findings identified in 18 AAC 50.030(c)(2), the contingency measure lowering the threshold for calling a Stage 2 alert will be triggered upon the effective date of the EPA finding.

EPA approved the contingency measure submitted as part of the 2020 Amendments as SIP-strengthening but proposed to disapprove the contingency measures submitted for the serious SIP and 2020 Amendments as not meeting the contingency measure requirements of CAA section 172(c)(9) and 40 CFR 51.1014. This findings was due to the emissions reduction from contingency measures not being sufficient to demonstrate the one year's worth of RFP and lack of demonstration if these measures would reduce emissions for the applicable $PM_{2.5}$ precursors, including SO_2, and NH_3.

EPA issued a final rule approving and disapproving portions of the Fairbanks area Serious SIP and 189(d) plan requirements effective on January 4, 2024. The disapproval includes sections of the control strategies and BACM analysis. The purpose of this 2024 SIP amendment is to resolve the disapproved portions of the Fairbanks area Serious SIP and 189(d) plan, which include revising and adopting regulations. A regulation package was released for public comment on March 11, 2024 and the public comment period closed on May 10, 2024. The regulations have not been formally adopted and are not listed in this section.

Outline for Remainder of the Section

The remainder of this document is organized to present the findings of updated analyses addressing each of the 5 BACM process steps outlined above. Section 2 presents a summary of the calculations prepared to quantify the baseline emission inventory (Step 1). A summary of the process followed to identify potential control measures is presented in Section 3 (Step 2). Section 4 presents the results of the technological feasibility analysis prepared for each of the measures identified in Section 3 (Step 3). Section 5 presents the results of the economic feasibility analysis for each measure determined in Step 3 to be technologically feasible (Step 4). Section 6 presents information on the earliest date at which measures determined to be technologically feasible (and/or adopted in a new state regulation) in Step 3 and economically feasible in Step 4 can be implemented (Step 5). Section 7 presents a summary of the selected control measures for consideration of implementation in the 2020 Amendment to the Serious SIP. Appendix A contains a reference to the state's economic analysis for Measure 51 (Ultra-low sulfur diesel), Measure 60 (Vehicle idling restrictions for light-duty and heavy-duty vehicles), Measure 68 (Charbroilers), and Measure 70 (Used-oil burners).

2. Step 1 – Develop a Comprehensive Inventory of Sources and Source Categories of Directly Emitted $PM_{2.5}$ and $PM_{2.5}$ Precursors

The first element in the multi-step BACM process consists of the development of an emission inventory (EI) of sources of directly emitted $PM_{2.5}$ and $PM_{2.5}$ precursors within the nonattainment area. This section describes that process. It includes a list of all source categories reflected in the inventory and a summary of the sources and activities in the nonattainment area. It also includes a summary of emissions by source category of both directly emitted $PM_{2.5}$ and its precursors.

Source Categories Inventoried

Overview - The inventory supporting the analysis for the 2024 Amendment Plan was developed in a manner consistent with the EI requirements for Serious Area (and CAA 189(d)) plans specified in EPA's $PM_{2.5}$ Implementation Rule[18] (or PM Rule). This included representation of source activity and emissions on a seasonal, rather than annual basis as provided for under the PM Rule. As discussed in the separate Emission Inventory document (Chapter III.D.7.06, and Appendix III.D.7.06), the use of seasonal estimates is appropriate for the 24-hour $PM_{2.5}$ standard in Fairbanks since violations of the standard are confined to winter months (October through March) and source activity that triggers these violations peaks during that time.

The inventory was developed using the 2020 base year emission inventory for the Fairbanks $PM_{2.5}$ nonattainment area. The base year inventory accounts for emission reductions from control measures adopted and implemented through December 31, 2019. The inventory was projected forward to calendar year 2027 and reflects growth, and controls in place at the end of 2027.

For all inventory sectors, episodic modeling inventory emissions were calculated using a "bottom-up" approach that relied heavily on an exhaustive set of locally measured data used to support the emission estimates. For source types judged to be less significant or for which local data were not available, estimates relied on EPA-developed NEI county-level activity data and emission factors from EPA's *Compilation of Air Pollutant Emission Factors*,[19] AP-42 database.

Figure 1 shows the boundaries of the Fairbanks $PM_{2.5}$ nonattainment area (shaded region) overlaid on the roadway system in the area. The nonattainment area covers 271 square miles. Figure 1 also shows the names and locations of the six major point sources located within the nonattainment area (using blue dots).

Sources Included and Pollutants Covered – The inventory included a review of all anthropogenic and biogenic emission sources within the nonattainment area. As described in greater detail in

[18] Federal Register, Vol. 81, No. 164, August 24, 2016 (FR 81 58010).

[19] Compilation of Air Pollutant Emission Factors," Fifth Edition and Supplements, AP-42, U.S. EPA, Research Triangle Park, NC. January 1995.

the Emission Inventory document, it was determined that biogenic emissions were negligible during the winter season represented in the inventory. In addition, fugitive dust sources of $PM_{2.5}$ were also estimated to be negligible under the snow/ice bound conditions reflected in the winter seasonal inventory.

Pollutants represented in the inventory consisted of both direct $PM_{2.5}$ as well as emissions of potential precursor pollutants: sulfur dioxide (SO_2), oxides of nitrogen (NOx), volatile organic compounds (VOC), and ammonia (NH_3).

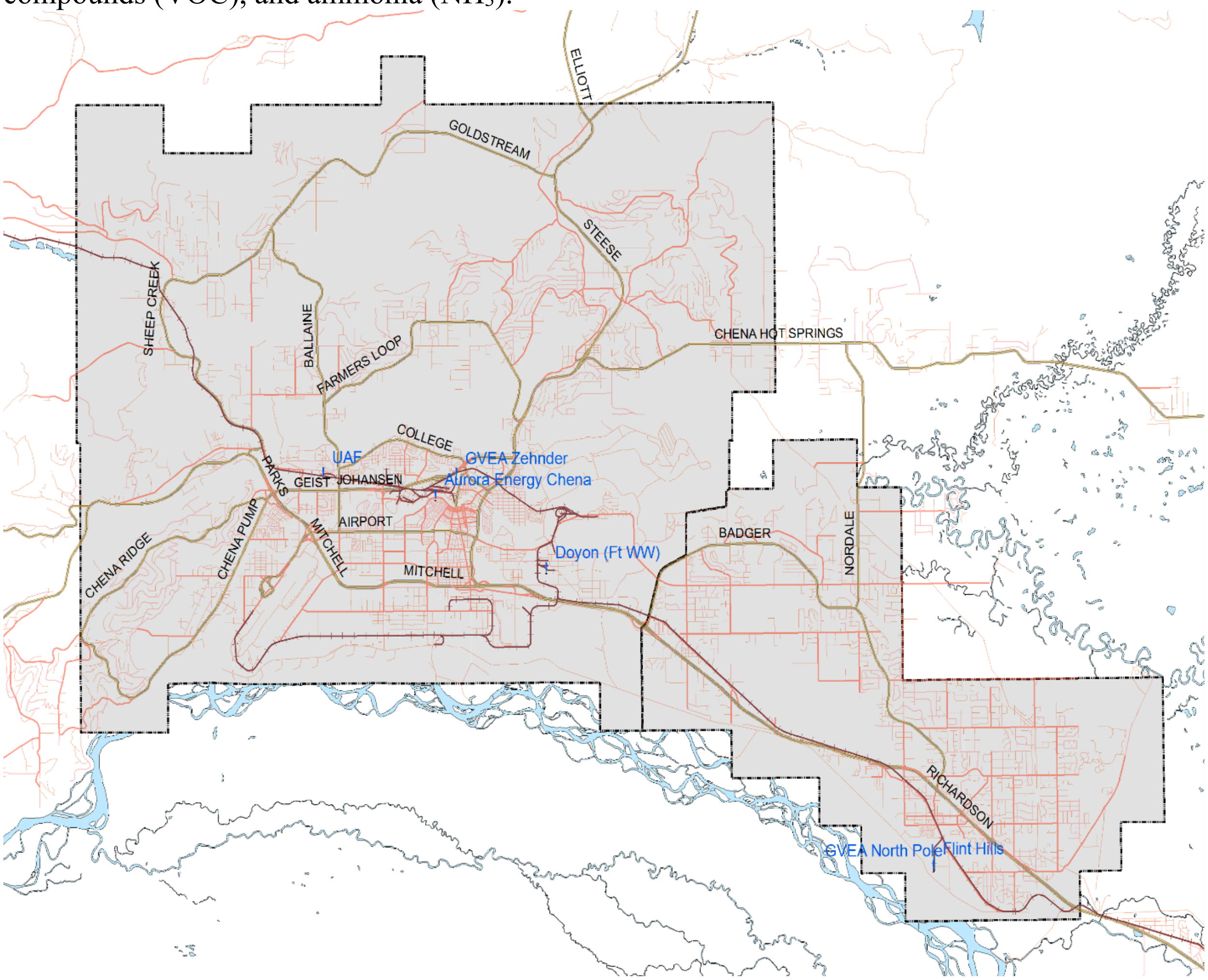

Figure 1. Fairbanks $PM_{2.5}$ Nonattainment Area

<u>Sources Included and Pollutants Covered</u> – The inventory included a review of all anthropogenic and biogenic emission sources within the nonattainment area. As described in greater detail in the Emission Inventory document, it was determined that biogenic emissions were negligible during the winter season represented in the inventory. In addition, fugitive dust sources of $PM_{2.5}$ were also estimated to be negligible under the snow/ice bound conditions reflected in the winter seasonal inventory.

Pollutants represented in the inventory consisted of both direct $PM_{2.5}$ as well as emissions of potential precursor pollutants: sulfur dioxide (SO_2), oxides of nitrogen (NOx), volatile organic compounds (VOC), and ammonia (NH_3).

Summary of Inventory Data Sources and Methods – Table 1 briefly summarizes the data sources and methods used to develop the emissions inventory by source type. It also highlights those elements based on locally collected data. As shown by the shaded regions in Table 1, the majority of wintertime activity and emission factor data supporting the inventory was developed based on local data and test measurements.

Table 1. Summary of Data/Methods Used in 2024 Amendment SIP 2020 Base Year Inventory

Source Type/Category	Source Activity	Emission Factors
Point Sources	Facility and stack-level fuel use and process throughput	Continuous emissions monitoring or facility/fuel-specific factors
Area (Nonpoint) Sources, Space Heating	Detailed wintertime Fairbanks non-attainment area residential heating device activity measurements and surveys	- Test measurements of common Fairbanks wood and oil heating devices using local fuels - AP-42 factors for local devices or fuels not tested (e.g., coal)
Area Sources, All Others	- Seasonal, source category-specific activity from a combination of State/Borough sources - National Emission Inventory (NEI)-based activity for commercial cooking	AP-42 emission factors
On-Road Mobile Sources	Local estimates of seasonal vehicle miles traveled	- MOVES3.1 emission factors based on local fleet/fuel characteristics - Augmented with Fairbanks wintertime vehicle warmup and plug-in emission testing data
Non-Road Mobile Sources	- Local activity estimates for key categories such as snowmobiles, aircraft and rail - MOVES3.1 model-based activity for Fairbanks for other categories	- MOVES3.1 model factors for non-road equipment - AEDT2c model factors for aircraft - EPA factors for locomotives

Within the inventory, activity and emissions were represented at the individual Source Classification Code (SCC) level, with the exception of the major point sources. Major point source emissions were compiled by SCC, facility and emission unit.

As evidenced by source classification structure used to highlight utilization of key local data sources, development of detailed episodic emission estimates to support the attainment modeling focused on three key source types:

1. *Stationary Point Sources* – industrial facility emissions for "major" stationary sources as defined later in this sub-section developed from wintertime activity and fuel usage;

2. *Space Heating Area (Nonpoint) Sources* – residential and commercial heating of buildings with devices/fuels used under wintertime episodic ambient conditions; and

3. *On-Road Mobile Sources* – on-road vehicle emissions based on local activity and fleet characteristics with EPA-accepted adjustments to account for effects of wintertime vehicle/engine block heater "plug-in" use in Fairbanks using MOVES3 (the latest version of MOVES at the time SIP development began for the 2024 Amendment).

As seen in emission summaries presented later in this sub-section, these three source types were the major contributors to both direct $PM_{2.5}$ emissions as well as emissions of potential precursor pollutants SO_2, NO_x, VOC, and NH_3 within both the nonattainment area as well as the broader Grid 3 modeling domain.

Revised Serious SIP Estimates – The Serious SIP contained a 2013 Baseline inventory. The 2020 Amendment was based on a 2019 Baseline inventory. The 2020 Baseline inventory for this 2024 Amendment was substantially updated for the 2020 base year based on new or revised activity estimates since the Serious SIP and 2020 Amendment development for which key elements are summarized below.

- Modeling Episode – As explained in detail in Section III.D.7.8, the 2024 Amendment included development of an entirely new photochemical modeling platform, and for the emission inventory, features a new, more current winter 2019-2020 modeling episode. Thus, as explained by source sector below, episodic emissions for the 2020 Base Year inventory were based on activity collected to represent this 74-day 2019-2020 period.

- Point Sources – Day and hour-specific fuel use for the new 2019-2020 modeling episode were obtained by ADEC from each of the point source facilities within the nonattainment area. Unlike the earlier baseline inventories for the Serious SIP and 2020 Amendment which projected episodic emissions from 2008 to 2013 and 2019 respectively, the 2020 Baseline point source inventory was based directly on these activity data as it temporally aligns with modeling episode.

- Space Heating Area Sources – Space heating energy usage estimates for the 2020 Baseline inventory were based on a comprehensive new Fairbanks Home Heating survey, conducted in Spring 2023. Respondents were asked to provide information on fuel usage by device in their household for the recent two calendar years (2021 and 2022) as well as the recent October through March six month winter period. Data from this 2023 survey was used to replace the projected space heating emissions developed under the Serious SIP and 2020 Amendments from earlier 2011-2015 surveys. The decreases in the fraction of wood devices used in the nonattainment area as well as the amount of wood use per device tracked well with downward trajectories of wood use expected from existing and on-going control programs such as the FNSB Wood Stove Change Out Program and DEC's Solid Fuel Curtailment Program. Results from 2022 and early 2023 period reflected in the new survey were also carefully backcasted to calendar year 2020 to account for changes in conditions and on-going control programs between the survey period and the 2020 Baseline inventory date.

- On-Road and Non-Road Mobile Sources – Under the Serious SIP and the 2020 Amendment, on-road vehicle populations and age distributions had been based on 2014 and 2018 DMV registration data, respectively. For the 2024 Amendment, 2020 DMV registration data were used to align with the 2020 Baseline inventory year. For on-road mobile sources, these 2020 DMV data were used to develop vehicle population, age distribution, and fuel type/technology inputs to the MOVES vehicle emissions model. Within the non-road mobile source sector, annual aircraft activity that had been assumed to be constant by month within the Serious SIP was revised under the 2020 Amendment to the Serious SIP based on monthly data collected from the airfields in the nonattainment area that showed less aircraft activity during winter months than the rest of the year. (Total annual aircraft operations remain unchanged from the Serious SIP, only the monthly distributions were revised.) The estimates of aircraft activity in the 2024 Amendment were unchanged from the approach used under the earlier 2020 Amendment.

Summary of Emissions

Emissions for the 2020 Baseline inventory within the Fairbanks $PM_{2.5}$ nonattainment area were updated from the Serious SIP, and 2020 Amendment based on new or revised activity estimates as summarized in the preceding section. They were tabulated by key source sector and updated to reflect the effects of growth through 2027 and controls in place at the end of 2027. Table 2 presents the resulting Control emission inventory estimates, expressed as average day emissions within the winter season for base year 2020. Emissions of direct $PM_{2.5}$ are highlighted in the first column. Precursor pollutant emissions are also shown. As seen in Table 2, space heating contributes the largest share of direct $PM_{2.5}$, with wood-burning being the dominant fuel type. For the gaseous precursor pollutants, point sources are the major contributors of NOx while SO_2 emissions are dominated by point sources, aircraft (within the non-road mobile sector), and space heating oil. Most VOC and NH_3 emissions are produced by space heating, with other contributions from mobile sources.

Table 2. 2020 Baseline Emissions Inventory (tons/day) by Source Sector

Source Sector	Nonattainment Area Winter Season Emissions (tons/day)				
	$PM_{2.5}$	NOx	SO_2	VOC	NH_3
Point Sources	0.58	13.51	6.54	0.04	0.087
Area, Space Heating	1.97	2.17	3.61	6.66	0.109
Area, Space Heat, Wood	1.89	0.23	0.04	6.55	0.067
Area, Space Heat, Oil	0.06	1.72	3.54	0.10	0.003
Area, Space Heat, Coal	0.00	0.00	0.00	0.00	0.000

Area, Space Heat, Other	0.02	0.22	0.02	0.01	0.039
Area, Other	0.11	0.36	0.03	2.12	0.047
Mobile, On-Road	0.07	1.18	0.00	1.42	0.040
Mobile, Aircraft	0.12	0.43	5.44	0.15	0.000
Mobile, Non-Road less aircraft	0.09	0.29	0.00	2.64	0.001
TOTALS	**2.95**	**17.94**	**15.63**	**13.04**	**0.285**

To provide a clearer understanding of the significance of each source sector, Table 3 provides a breakdown of the percentage contributions of each sector (or subcategory) to total emissions for each pollutant. As shown in Table 3 over 60% of direct $PM_{2.5}$ comes from space heating. Point sources contribute just under 20% of direct $PM_{2.5}$, with other area sources and mobile sources accounting for the remaining 13%. For NOx, point sources are the major contributor, accounting for 75% of total emissions. Space heating is the second largest NOx source, representing 12%. SO_2 emissions come primarily from point sources (42%), with mobile aircraft sources as the next largest share at 35%.

Table 3. 2020 Baseline Emissions Inventory
Contributions by Source Sector (% of total pollutant emissions)

Source Sector	**Nonattainment Area Winter Season Emissions (tons/day)**				
	$PM_{2.5}$	**NOx**	**SO_2**	**VOC**	**NH_3**
Point Sources	19.6%	75.3%	41.9%	0.3%	30.7%
Area, Space Heating	67.1%	12.1%	23.1%	51%	38.2%
Area, Space Heat, Wood	64.2%	1.3%	0.3%	50.2%	23.4%
Area, Space Heat, Oil	2.2%	9.6%	22.7%	0.7%	1.2%
Area, Space Heat, Coal	0.1%	0%	0%	0%	0.1%
Area, Space Heat, Other	0.6%	1.2%	0.1%	0.1%	13.5%
Area, Other	3.9%	2%	0.2%	16.3%	16.4%
Mobile, On-Road	2.5%	6.6%	0%	10.9%	14%
Mobile, Aircraft	4%	2.4%	34.8%	1.2%	0%
Mobile, Non-Road less aircraft	3.1%	1.6%	0%	20.3%	0.5%
TOTALS	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

Since the portion of emission sources encompassing all categories except point sources are subject to 5% emission reductions for control measures and recently adopted regulations (point sources are addressed under BACT), these tabulations show that space heating continues to be the dominant, but not singular source of emissions under the 2024 Amendment to the Serious SIP.

3. Step 2 – Identify Potential Control Measures

The second step in the 2024 Revised Amendment Plan identification and evaluation process is to identify candidate control measures. In this step, a list of control measures potentially applicable to the mobile and area source $PM_{2.5}$ source categories is developed for consideration for a plan amendment required under CAA Section 189(d). States are required to examine a wide range of information sources on existing and potential control measures in the search for candidate control measures. The Final $PM_{2.5}$ Rule requires the list of potential controls to include "options not previously considered as BACM", control measures being implemented in other nonattainment areas, and measures considered by regional planning organizations and state and local air quality consortiums. The goal is to identify a list of control measures that are more stringent than those adopted in the Serious Area SIP.

The process followed to select control measures for the 2024 Revised Amendment was to assemble a list of the control measures not adopted in the Serious SIP and the 2020 Amendment and to review the control measures implemented in serious $PM_{2.5}$ nonattainment communities to determine if any revisions had been adopted since the submission of the 2020 Amendment to the Serious SIP. A review of the following air quality regulatory agencies was conducted to determine if any control measures were adopted since the submission of the 2020 Amendment.

- San Joaquin Valley Air Pollution Control District (SJVAPCD), CA
- Bay Area Air Quality Management District (BAAQMD), CA
- South Coast Air Quality Management District (SCAQMD), CA
- Utah Division of Air Quality (UDAQ), UT
- Northern Sierra Air Quality Management District, CA
- Sacramento Metropolitan Air Quality Management District (SMAQMD), CA
- City of Berkeley
- Texas Commission of Environmental Quality (TCEQ), TX
- New York City Department of Environmental Protection (NYCDEP)
- Puget Sound Clean Air Agency (PSCAA), WA
- Vermont Air Quality and Climate Division (VAQCD)
- Colorado Department of Public Health and Environment (CDPHE), CO
- San Diego Air Pollution Control District (SDAPCD), CA
- Oregon Department of Environmental Quality (ODEQ), OR

The following jurisdictions have updated SIPs since the submission of the 2020 Amendment and ADEC reviewed these in detail to assess if there were any new control measures to be evaluated for the 2024 Amendment.

- The Northern Sierra Air Quality Management District submitted an updated contingency measure SIP revision[20] as part of the moderate area SIP in October 2020 for Plumas County, in California which was approved by EPA in 2021. In November 2022, the EPA determined that the Portola NA failed to attain the 2012 $PM_{2.5}$ NAAQS by December 31, 2021, moderate area attainment date and reclassified the area to serious. In the updated Plan, the district

[20] CARB. Proposed Portola $PM_{2.5}$ Plan Contingency Measure SIP Submission. October 16, 2020.

developed several contingency measures that reduced $PM_{2.5}$ emissions equivalent to one year's worth of progress. Firstly, the district updated the residential wood burning curtailment program by lowering the thresholds from 30 to 20 µg/m^3 and extended the program duration from Nov – Feb to Sep – April (for 8 months) for Zone 1 comprised of the City of Portola. Secondly, the district extended the incentive-based wood stove change-out program beyond 2020 due to the COVID-19 delays. In addition, the district planned to implement a voluntary curtailment program in Zone 2 (the rest of the Plumas County nonattainment area) and use the weatherization assistance program for low-income households to weatherize 30 summer cabins that are being used for all-year-round residences.

ADEC's curtailment control measure is already stringent set at 20µg/m^3 for Stage 1 and 30 µg/m^3 for Stage 2 Alert compared to the curtailment levels in Portola. Further, extending the curtailment duration beyond winter months is irrelevant as the nonattainment period in Fairbanks is only during winter. In addition, there is an ongoing woodstove change out program, and several voluntary weatherization programs in the Nonattainment Area.

- The San Joaquin Valley Air Pollution Control Board and CARB developed the Initial SIP in October 2023[21] as a result of EPA's reclassification of the San Joaquin Valley as a Serious nonattainment area for the 2012 $PM_{2.5}$ annual NAAQS, and CARB withdrawing the portions of the 2018 $PM_{2.5}$ Plan for the 2012 $PM_{2.5}$ NAAQS. This initial submission prepared 18 months after the effective date of reclassification focuses on the BACM analysis, emissions inventor, precursor analysis, and nonattainment new source review. Although this Plan has not been reviewed by EPA, ADEC assessed the Plan as the SJVAPCD is one of the most reviewed SIP's as part of BACM Step 2 in identifying potential control measures. A comparison of SJVAPCD control measures that were referred to in the Fairbanks 189(d) Plan versus the changes in the 2023 Initial Serious SIP is provided in Table 4.

Table 4. Evaluation of Control Measures from SJVAPCD SIP

SJVAPCD Control Measures referred to in the Fairbanks 189(d) Plan	2023 SJVAPCD Initial Serious SIP
Wood Burning Fireplace and Wood Burning Heaters (SJVAPCD Rule 4901)	
DEC Measure 4: Require Confirmation of Proper Installation by Requiring Professional Installation or On-Site Inspection	No changes to these requirements.
DEC Measure 5: Register/Require Industry Certification of Heating Professionals	No changes to these requirements.
DEC Measure 9: Limit the density of solid-fuel heating devices in new construction	No changes to these limits.
DEC Measure 19: Require Registration of Devices to Qualify for Exemption from Curtailments	No changes.
DEC Measure 20: Require Renewals with Inspection Requirements: Registration	No changes.

[21] SJVAPCD. Initial SIP Requirements for the 2012 Annual PM2.5 Standard. October 19, 2023.

requirements and operation during curtailment periods	
DEC Measure 21: Optional Device Registration for Curtailment Exemptions	No changes.
DEC Measure 26: Require Inspection of Device and Installation	No changes.
DEC Measure 32: Require Dry Wood to be Clearly Labeled to Prohibit Marketing of Non-Dry Wood as Dry Wood	No changes.
DEC Measure 46: Lack of electrical or natural gas service availability	No changes.
DEC Measure 66: Curtailment Threshold	In May 2023, the district amended Rule 4901 to establish a sequence of increasingly stringent contingency curtailment thresholds for all counties that would be triggered upon the contingency measure requirements. • Contingency measure 1 to lower the level 1 and level 2 thresholds for non hot-spot counties from 20 to 12 $\mu g/m^3$ and 65 to 35 $\mu g/m^3$ respectively. No changes were proposed for hot-spot counties. • Contingency measure 2 to further lower the level 1 thresholds for all counties from 12 to 11 $\mu g/m^3$ and no changes for level 2 set at 35 $\mu g/m^3$.
Charbroilers (SJVAPCD Rule 4692)	
DEC Measure 68: Underfired charbroilers are not subject to the requirements of Rule 4692, except for reporting requirements. The district rejected control DEC Measures based on economic infeasibility for underfired charbroilers.	No changes. The district has identified new control technologies to reduce emissions from underfired charbroilers (in addition to ESP, filtration, regenerative filters, and wool filters have been added as viable control technologies). The district also updated the CE numbers compared to previous BACM analysis which continue to be economically infeasible.
Incinerators (SJVAPCD Rule 4203)	
DEC Measure 69: Incinerators	No changes.
Transportation Control Measures (TCMs)	
The 2018 SJV PM2.5 Plan relied on the TCMs originally submitted as part of a 2002 Severe Ozone Plan, and the selection or dismissal of TCMs was based solely on qualitative assessment.	The district conducted a BACM analysis for the 2023 Plan and did not identify any new measures for implementation as the ongoing TCMs meet the BACM requirements.
Weatherization	
One of the components of Rule 4901 that relates to weatherization is the public education and outreach program.	No changes.

Based on this evaluation, except for revised contingency measures, there are no new control measures to be considered for the 2024 Amendment. Similar to the San Joaquin Valley, in the 2024 Amendment, ADEC is revising the contingency measures to meet the requirements of CAA section 172(c)(9) and 40 CFR 51.1014. The measures would increase the stringency of the Curtailment Program thresholds/alert levels for wood-fired heating devices and increase compliance with Wood Device Removal (STF-17) measure. The contingency measure would lower the Stage 1 level from 20$\mu g/m^3$ to 15$\mu g/m^3$ and Stage 2 level from 30$\mu g/m^3$ to 20$\mu g/m^3$ and increase compliance for STF-17 from 30% to 45%. Contingency measures are explained in Section III.D.7.11. Based on the revised contingency measures, the curtailment program in the Fairbanks Nonattainment Area is as stringent as the San Joaquin Valley because the alerts apply to the entire Nonattainment Area and level 1 threshold is at 12$\mu g/m^3$ compared to ADEC's Stage 1 at 15$\mu g/m^3$, and level 2 threshold is at 35$\mu g/m^3$ compared to ADEC's Stage 2 at 20$\mu g/m^3$.

- Yuba City-Marysville Area, Sacramento: CARB submitted the second maintenance plan for $PM_{2.5}$ in April 2023. As this is a maintenance plan, a review of this Plan is not required as part of the BACM step 2 process.

The review of the control measures employed in these $PM_{2.5}$ programs determined that no new measures had been implemented since the submission of the 2020 Amendment to Serious SIP.

Listed below are the measures that were not adopted because they were determined to be technologically infeasible (Step 3), economically infeasible (Step 4) or could not be implemented within the required timeframe (Step 5). Also listed is the source of the control measure, which includes the community implementing the measure, EPA comments, and comments submitted for the Fairbanks RACM and BACM analyses.

A wide range of rules implementing SIP controls were examined to identify control measures for consideration as BACM and 2024 Revised Amendment Plan control measures. Several states and local jurisdictions were found to have multiple rules addressing $PM_{2.5}$ control. Most rules are extensive and contain separate sections addressing definitions, prohibitions, stage restrictions, exemptions, penalties, etc. Use of these links facilitated the comparative evaluation of control program requirements in the Fairbanks North Star Borough and State of Alaska to those of other jurisdictions to determine if those of other jurisdictions are potentially more stringent than corresponding Fairbanks area requirements - the screening qualification for consideration as BACM as well as for consideration as control measures under CAA Section 189(d) requirements.

After reviewing the range of $PM_{2.5}$ control programs in place across the country, it became apparent that many had similar structures, and detailed requirements reflecting local decisions about how best to implement needed controls. Since the programs reviewed did not fit into a uniform template, evaluations of them had to be conducted in a careful manner to understand requirement nuances. Definitions differ, prohibitions and thresholds for implementation differ, exemptions frequently differ, etc. Thus, while it was tempting to contrast entire regulatory packages to determine which provided the largest reduction in emissions, quantification of reductions was found to be a complex exercise because of the numerous regulatory differences between these packages and that of Fairbanks. Several of the findings made during this initial approach were that:

1. Considerable effort would be required to develop separate spreadsheets for each regulatory package to quantify overall emission benefits in Fairbanks;
2. Individual components of regulatory packages that could provide benefits in Fairbanks could be missed if other components of the same packages offset these benefits when packages were considered in total (i.e., throwing the baby out with the bathwater);
3. Comparisons of individual regulatory elements is easier to analyze and present for review;
4. Comparisons of individual regulatory elements do not require spreadsheet analysis to determine which elements are more stringent;
5. Frequently, the data or estimates needed to contrast measures quantitatively do not exist: impacts on emissions due to differences in exemption details, approved device categories, installation requirements, curtailment requirements, enforcement policies, shifts in behavior, etc.

Collectively, the issues listed above led to a decision to contrast elements of regulatory packages with those of the Borough and the State of Alaska. The search for regulatory elements that appeared to be more stringent than those in Fairbanks and Alaska regulations first produced a list of jurisdictions implementing them and web links to the applicable regulations.

The next step was to isolate the specific elements in these rules and regulatory packages that appeared to be more stringent than the corresponding elements in FNSB and Alaska regulations. These elements were assigned short descriptive titles and then organized into groups of common functionalities. In other words, all the specific elements that regulated device installation were grouped together under the group title of "Device Installation – General". Element groups were then organized in a sequence that followed the chronological events in device acquisition, use, and retirement, such as sale, installation, permitting, exemption granting, operation, curtailment during air quality advisories, and removal. Because the analysis of source categories contributing to $PM_{2.5}$ nonattainment in the Borough identified coal burning, heating oil combustion, and motor vehicle travel as being significant, elements of regulations implemented by other jurisdictions that addressed these sources were grouped together in separate categories.

The list of these functionality groups and individual regulatory elements evaluated and not adopted in the Serious SIP, and 2020 Amendment is presented in Table 5. Listed with each regulatory element are the jurisdictions implementing these elements. Because some of the measures came from a mixture of sources that were not implementing jurisdictions, they were grouped into the last "Other" category. They included (a) EPA comments[22] on the draft BACM document in May 2018 that identified several additional control measures to be addressed in the analysis. In addition (b), analysis of commercial controls in process at the time of the release of the draft 2020 Amendment were completed and are included in this analysis. Finally (c), comments received from the public on the Moderate SIP suggested additional control measures

[22] Attachment to a letter from Dan Brown to Denise Koch, 5/23/2018, EPA comments on ADEC Preliminary Draft Serious SIP Development materials for the Fairbanks serious PM2.5 nonattainment area.

and were included in the original RACM analysis, not adopted, considered in the BACM analysis, and not adopted, and (d) comments received from EPA on the 2020 Amendments.

In the Serious Area SIP Section 7.7, control strategies from the Air Quality Stakeholders recommendations were cross-referenced with the BACM analysis and final regulation package. Due to the multiple processes for identifying control measures, and the overlap between the measures, a crosswalk and summary was developed in Table 7.7-6 of the Serious Area SIP. The crosswalk and summary table were reviewed to determine if any Air Quality Stakeholder measures were identified but not adequately addressed. The results of the review show that each Air Quality Stakeholder measure was either associated with a control measure in the Serious Area SIP BACM analysis, or was classified as non-regulatory, or was a recommendation for named point sources and addressed in the BACT analysis.

Table 5. Control Measures Implemented in $PM_{2.5}$ Nonattainment Areas and Suggested in SIP Comments That Have Not Been Implemented in FNSB or only Implemented in Part.

Measure Description	Areas Implementing Measure
Sale of Devices - New	
1. Surcharge on Device Sales	Washington State
Sale of Devices – Used	
6. Prohibit installation of flue dampers unless device was certified using a flue damper	Missoula County, MT
8. Prohibit installation of Solid Fuel Heating Device (SFHD) in new construction	South Coast Air Basin, CA San Joaquin Valley, CA Bay Area, CA
9. Limit the density of SFHD in new developments	San Joaquin Valley, CA East Kern, CA
10. Install EPA-certified device whenever a fireplace or chimney is remodeled	Bay Area, CA
Device Installation - Hydronic Heaters	
11. Prohibit use of rain caps on stacks	Maine, ME
12. Require minimum stack height relative to rooflines of nearby unserved buildings	Maine, ME New York, NY Utah, UT
14. Require installation of thermal mass to improve efficiency and prevent frequent cycling in selected new units	U.S. Environmental Protection Agency
Device Operation – Opacity	
18. No Visible Emissions during Curtailment Periods	Puget Sound CAA, WA Maricopa County, AZ
Device Operation – Permits	
23. Require exempt households to display a decal visible from a point of public access	Ada County, ID
Device Operation – NOASH	
25. Require detailed application or inspection to verify need	Puget Sound CAA, WA

Measure Description	Areas Implementing Measure
27. Require annual renewal of waiver	Maricopa County, AZ
28. Set income threshold	Missoula County, MT Maricopa County, AZ
29. Allow only NOASH households to burn during curtailment periods	Utah, UT
Fuels	
31. Require sale of only dry wood during late summer to end of winter	South Coast Air Basin, CA
32. Require dry wood to be clearly labeled to prohibit marketing of non-dry wood as dry wood	San Joaquin Valley, CA Bay Area, CA
Open Burning	
35. Restrict burning during air pollution events	Ada County, ID Klamath County, OR
Curtailment Programs – Averaging Period	
38. Ambient $PM_{2.5}$ concentration (1-hr average)	Idaho, ID
Curtailment Programs – Thresholds	
39. Use of AQI as Basis for Curtailment Threshold	Idaho, ID
Curtailment Program – Exemptions	
42. Burn down period	Puget Sound CAA, WA Maricopa County, AZ
45. Elevation-based	South Coast Air Basin, CA
46. Lack of electrical or natural gas service availability	Utah, UT South Coast Air Basin, CA San Joaquin Valley, CA
Coal	
50. Require low sulfur content coal	Missoula City-County, MT Puget Sound CAA, WA
Ultra-low Sulfur Diesel/Heating Oil	
51. Ultra-low Sulfur Heating Oil	Missoula City-County, MT New York, NY Pennsylvania, PA
Used Oil	
52. Operation and sale of small “pot burners” prohibited	Vermont, VT
53. No Sale or Exchange of Used Oil for Fuel, unless it Meets Constituent Property Limits	Vermont, VT
Transportation	
54. Adopt CARB vehicle standards	Pennsylvania, PA Klamath County, OR
55. School bus retrofits	Klamath County, OR
56. Road paving	Nogales, AZ Pinal County, AZ Klamath County, OR
57. Transportation Control Measures (TCMs)*	South Coast Air Basin, CA
58. Controls on road sanding and salting	Utah, UT

Measure Description	Areas Implementing Measure
59. I/M Program*	Pennsylvania, PA
60. Vehicle Idling	EPA Comment
Other	
61. Fuel Oil Boiler Upgrade – Burner Upgrade/Repair	EPA Comment
62. Fuel Oil Boiler Upgrade – Replacement	EPA Comment
63. Require Electrostatic Precipitators	FNSB
64. Weatherization and Energy Efficiency	EPA Comment City of Berkeley, CA San Joaquin Valley, CA South Coast Air Basin, CA Dallas-Ft Worth, TX
67. Coffee Roasters	Commercial/ EPA Comment Vermont Colorado
68. Charbroilers	Commercial/ EPA Comment
69. Incinerators	Commercial
70. Used Oil Burners	FNSB/ EPA Comment
R1. Regional Kilns	RACM
R7. Ban Use of Hydronic Heaters	RACM
R15. Ban New Installations – Wood Stoves	RACM
R17. Ban Use of Wood Stoves	RACM
R20. Transportation Control Measures	RACM
R29. Increase Coverage of District Heating System	RACM

* Measures 57 & 59 are addressed in the Measure R20 Transportation Control Measure feasibility analysis.

All of the above controls are focused on the reduction of particulate emissions. As noted in the Modeling Chapter of the $PM_{2.5}$ Serious SIP neither VOC nor NOx are significant precursor pollutants in the Fairbanks $PM_{2.5}$ nonattainment area. There is no need to identify control measures for these precursor pollutants. With regard to ammonia, EPA commented that "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 point sources." While a precursor demonstration of NH_3 insignificance is not feasible, a literature search for non-point source ammonia controls found no controls for Fairbanks emission sources. Controls addressing agriculture and animal waste ammonia, the predominant sources in lower-48 communities, are well documented, but those sources do not exist in Fairbanks. Therefore, no ammonia controls have been included in the 2020 Amendment Plan analysis. EPA in its Final Rule,[23] approved ADEC's analysis that found no NH_3 specific emission controls in the Fairbanks Nonattainment Area.

[23] 88 Fed. Reg. at 84636.

4. Step 3 – Determine Whether an Available Control Measure or Technology is Technologically Feasible

The third step in the 2020 Amendment Plan identification and evaluation process is the analysis of the technological feasibility of each of the candidate measures identified in Step 2. As noted above, it requires the consideration of many factors including impacts on the environment (e.g., air, water, noise, etc.) and energy (e.g., consumption, availability, etc.). Measures targeting area and mobile sources need to consider infrastructure, population size, workforce type and habits, etc. In addition, the critical source parameters needed to assess the impacts of the technology need to be identified (e.g., fuel specifications, travel activity, EPA certification, etc.). A key consideration is whether the identified measure provides an emissions benefit beyond those provided by existing federal, state and local controls (i.e., is it more stringent).

As discussed in Step 2 the approach employed in selecting measures for analysis focused on differences between elements of individual rules implemented in $PM_{2.5}$ nonattainment areas and those currently implemented by the Borough and the State for the Fairbanks $PM_{2.5}$ nonattainment area. This section provides the results of detailed comparisons between the selected candidate measures and existing State regulations to determine if the candidate measures are more stringent and can provide emission reductions beyond those of currently implemented measures. Step 2 identified a total of 47 control measures for consideration in 2020 Amendment analysis. Following EPA's comments on the 2020 Amendment, Step 2 identified a total of 11 control measures from the list of 47 measures from the 2020 Amendment for re-evaluation for the 2024 Amendment. **<u>While all 47 measures are presented in this section, the set of 11 measures re-evaluated for the 2024 Amendment are presented in bold and underlined format.</u>** The presentation of analysis findings follows a generic format with the following components:

- Measure #, Title
- Implementing Jurisdiction
- Regulation Weblink(s)
- Background
- Analysis
- Conclusion

This format is designed to provide transparency in the information used to prepare the analysis. The weblink(s) allow easy access to the referenced rules discussed in the background and analysis presentations.

<u>Measure 1: Surcharge on Device Sales</u>

<u>Applicable Jurisdiction(s)</u>

- Washington State

<u>Regulation Weblink(s)</u>

- https://dor.wa.gov/find-taxes-rates/other-taxes/solid-fuel-burning-device-tax

Background

A Washington State regulation imposes a fee upon the sale of solid fuel wood burning devices within the state. This regulation was adopted in or prior to 1987.[24] The fee, originally established at $15/unit, is currently set at $30/unit.[25]

This regulation requires that revenues from the program be used solely for the purposes of public education and enforcement of the solid fuel burning device program," with revenue distributed as follows:

a) 34% of the funds shall be distributed to the Woodsmoke Education Program, run by the state air agency, the Washington Department of Ecology, for the purposes of enforcement and educating the public about the effects of solid fuel heating devices on air quality and methods for achieving better efficiency from solid fuel burning devices; and
b) The remaining 66% of the funds are made available to local air authorities with enforcement programs under the Woodsmoke Enforcement Program on the basis of population.

If a local air authority is not in place, does not implement an enforcement program, or elects not to receive the funds, the funds that would otherwise be distributed under this subsection are transferred to the Department of Ecology. Businesses selling new wood stoves are also required to distribute and explain educational materials.

The biennial 2015-2017 budget for the Washington Department of Ecology estimated an income of $547,000 from the combined Woodsmoke Education and Enforcement Program, with $38,000 being allocated to the Department of Ecology for administration of affected programs and $509,000 allocated to the Air Quality Program. Of this $509,000, 34% (or roughly $173,000) was used to fund the <u>statewide</u> Woodsmoke Education Program. $274,000 of the remaining 66% (or $336,000) was disbursed to <u>local agencies</u> to fund both woodstove education and enforcement grants.[26] (Not all of the available funds are requests.)

EPA commented that implementing 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."

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[24] Washington Laws, 1990, available at http://leg.wa.gov/CodeReviser/documents/sessionlaw/1990c128.pdf?cite=1990%20c%20128%20%C2%A7%206; Accessed 10/10/2017.
[25] Washington State Department of Revenue, available at https://dor.wa.gov/find-taxes-rates/other-taxes/solid-fuel-burning-device-tax; Accessed 10/10/2017.
[26] State of Washington Department of Ecology, Budget & Program Overview 2015-2017, available at https://fortress.wa.gov/ecy/publications/documents/1501007.pdf; accessed 10/12/2017.

Analysis

Discussions with Washington Department of Ecology staff[27] found that surveys they conducted were not able to clearly estimate emission benefits from state-level education/outreach, nor were they able to provide quantitative estimates of their emission benefits based on how funds were pooled and used by local agencies. Similar findings were confirmed based on communication with the Puget Sound Clean Air Agency, one of the local air authorities that receives funding from the Department of Ecology. They too combine funds received from the Wood Stove Education and Enforcement program with revenues from other sources and use the funding for education and enforcement related to burn restrictions, but they could not easily quantify the benefits of the specific funded programs. In addition, the revenues received from this program by the local agencies are small relative to the funds received from other sources.[28]

Given the co-mingling of monies from device sale surcharges with other funding sources, both Washington State and its local air agencies cannot easily estimate emission benefits attributed to either education or enforcement-related programs.

Another consideration is that DEC has no authority to collect the funds obtained through surcharges. Funds collected from surcharges in Alaska go straight into the state's general fund, they are not allocated to DEC unless the legislature appropriates those funds to the agency. The implementation of this measure would require the annual allocation of the collected funds to DEC for use in enforcement and/or education. The uncertainty of this allocation means that the measure is not permanent and enforceable, and therefore does not support a SIP commitment. The only way that could occur would be through a Constitutional Amendment. The Dedicated Funds Clause of the Constitution of the State of Alaska prohibits the dedication of "proceeds of any state tax or license" to "any special purpose." AK Const. Art. 9 § 7. A constitutional amendment changing this long-standing provision is highly unlikely. Even if support could be garnered, multiple years would be required to amend the state constitution.

Conclusion

ADEC lacks the authority required to implement this measure, therefore it is technologically infeasible and cannot be considered as a measure for the 2020 Amendment to the Serious SIP.

Measure 6: Prohibit Installation of Flue Dampers Unless Device was Certified Using Flue Damper

Applicable Jurisdiction(s)

- Missoula, Montana

Regulation Weblink(s)

[27] Personal communication with Stuart Clark, Washington Department of Ecology, 10/12/2017. Personal communication with Matthew Vandrush, Washington Department of Ecology, 10/12/2016.
[28] Personal communication with Amy Warren, Puget Sound Clean Air Agency, October 13, 2017.

- https://www.missoulacounty.us/home/showdocument?id=8452

Background

With respect to enclosed combustion devices, the term "draft" refers to the negative pressure created at the air inlet to the combustion chamber by the buoyancy of hot combustion gases exiting the combustion chamber through a vertical stack or chimney. The magnitude of stack draft is primarily governed by the difference in temperature between outdoor air and the combustion gases within the stack, and the volume of the stack (or chimney). Since outdoor air and stack gas temperatures change both seasonally and during a typical diurnal heating cycle, the amount of draft can vary similarly.

In residential wood stoves and inserts, inlet air and combustion gas flow rates are generally controlled by a damper installed at the inlet air ports to the combustion chamber. Where building codes and wood burning regulations allow, dampers can also be installed downstream of the combustion chamber in the exhaust stack to directly regulate combustion gas flow rates. Many dampers require manual adjustment, but some are thermostatically controlled to open the damper when combustion chamber temperatures decline during the burndown phase.

Solid fuel burning appliances are designed to operate within an optimum draft range. If the draft is set too low, insufficient air is available to sustain combustion except when very small quantities of fuel are present in the combustion chamber. If the draft is set too high, excess air (beyond what is needed for proper combustion) is allowed into the combustion chamber which reduces combustion temperatures and reduces the device's heating efficiency (resulting in increased fuel use) and may also result in unsafe operation. The optimum range of draft for properly installed and operated residential wood-burning devices such as wood stoves and fireplace inserts typically falls in the negative pressure range of minus 0.04 to 0.08 inches of water column.

Analysis

The BACM analysis of this measure is unchanged - Missoula, Montana is the only jurisdiction to enforce a regulation prohibiting the installation of a flue (exhaust stack) damper unless the device is specifically certified with a flue damper. The staff from the Montana Department of Environmental Quality could not locate a staff report associated with the adoption of this regulation by their Board in 1986 as part of the Montana Clean Air Act. They also suggested that no analysis was conducted to review the likely impact of flue damper installation on emissions prior to adoption.[29]

During wintertime conditions in Fairbanks flue draft varies dramatically beyond the optimal range due to wider temperature differences between flue gases and ambient air. When outdoor temperatures fall to the -10 to -20°F range typical of ambient $PM_{2.5}$ violations in Fairbanks, draft negative pressures can reach or exceed minus 0.20 inches of water column, which is well in

[29] Personal communication with Julie Mohr, Montana Department of Environmental Quality, October 5, 2017; Personal communication with Benjamin Schmidt, Missoula City/County Health Department, October 6, 2017.

excess of the typical design ranges for wood stoves and inserts.[30] Under these conditions, resident time of hot combustion gases in a wood stove or fireplace insert will be reduced, increasing the quantity of fuel needed to be burned to maintain the target indoor temperature. Thus, use of a flue damper will reduce inlet air and exhaust gas flowrates and the resulting draft to within the designed operating ranges of woodstoves and fireplace inserts and provide an emissions reduction benefit through reduced fuel consumption. With regard to the installation of new wood burning devices, the 2015 NSPS mandates that owner manuals specify whether flue dampers are required and professional installers are required to observe installation instructions. 18 AAC 50.077(j) requires the use of installers certified by the National Fireplace Institute and/or the Masonry Heaters Association as appropriate.

Conclusion

The BACM analysis concluded that the benefits of this measure in an arctic environment are likely to increase emissions through increased fuel combustion. That finding has not changed, this rule will produce no benefit for new installations; therefore the measure is technologically infeasible and not eligible for consideration as a control measure for the 2020 Amendment to the Serious SIP.

Measure 8: Prohibit Installation of Solid Fuel Heating Device in New Construction

Implementing Jurisdiction(s)

- South Coast AQMD, Bay Area AQMD

Regulation Weblink(s)

- http://www.aqmd.gov/docs/default-source/rule-book/rule-iv/rule-445.pdf?sfvrsn=4
- https://www.baaqmd.gov/~/media/dotgov/files/rules/regulation-6-rule-3/documents/20191120_r0603_final-pdf.pdf?la=en

Background

The South Coast Air Quality Management District prohibits the installation of a wood-burning device into any new construction (Section 445.d.1) except in new developments where no natural gas service exists within 150 feet of the property line (Section 445.f.2). Devices installed in new construction without natural gas service are limited to USEPA certified wood-burning heaters, pellet stoves, masonry heater, or dedicated gaseous-fueled fireplaces (Section 445.d.2). South Coast AQMD does not require a permit for device installation or operation.

The Bay Area Air Quality Management District prohibits the installation of a wood-burning device in any new construction building effective November 1, 2016 (Section 6-3-306). The Bay

[30] Personal communication with Kent Severns, The Woodway, Fairbanks, AK, October 6, 2017.

Area regulation does not provide an exemption from this requirement in areas not served by natural gas infrastructure.

Fairbanks had regulations addressing the installation of solid fuel devices in new construction, but they were removed with the passage of the Home Heating Reclamation Act. The state has no regulations governing installation of wood-burning devices specific to new construction but does have 18 AAC 50.077 governing the sale and installation of any wood fired heating device which covers not only new construction but also all sales and installations in existing construction.

Analysis

While Fairbanks currently has natural gas service, it is capacity constrained and will not be in a position to expand service to new customers until 2020 in Fairbanks and 2021 in North Pole.[31] As a result, the installation requirements in the South Coast rule that would be applicable if adopted by the state would be limited solely to the type of device installed.

Alaska has implemented new regulations that establish more stringent emission ratings for new heating devices and related installation requirements. Those regulations, however do not prohibit the installation of wood-burning devices in new construction. Backup heating systems are essential for survival in an arctic environment as loss of primary heating is not an uncommon occurrence with many causes including: extreme cold temperatures, ice storms, fuel supply loss, power outages, etc. ADEC has required in regulations effective January 8, 2020, that wood heaters may not be installed as a sole source of heat in structures within the nonattainment area, with an exception for small, dry cabins on two acre or larger parcels (see 18 AAC 50.077(j)(2)).

ADEC often hears from FNSB residents who have significant concerns regarding the need for non-electric backup heating systems in their homes. As described in the Emission Inventory, the predominant heating method within the residential space heating sector is residential fuel oil. All fuel oil boilers and heaters require electricity to operate the auxiliary systems such as fans and pumps. Given the subarctic climate and periodic power failures, these individuals have real safety concerns for themselves and their families as well as concerns about damage to their property.

These concerns and expressed needs for reliable backup heat are likely very different in the FNSB nonattainment area than in the San Francisco Bay Area where the BACM prohibition originates. However, based on the Borough's woodstove changeout/conversion program it is technically feasible to design a new home with adequate backup heating systems that do not rely on solid fuel heating appliances.

Even though it may be technically feasible in certain situations, without widespread availability toof natural gas there are limited technologies to provide backup heat to address the safety concerns. While voluntary programs are in place, only 28 emergency power back up systems have been installed through the Borough's program. With the limited number of actual installations, ADEC is cautiously optimistic that the emergency power back up systems will become a proven technology, but at this point the limited installations do not demonstrate that

[31] AIDEA IGU Financing Agreement op. cit., Appendix A

this technology is feasible in every situation. Due to the importance of these systems to ensure citizens safety in an arctic climate, it is not prudent to exclude an entire sector of proven residential heating technology that many citizens rely on for an immediate safety concern.

In order to address new installations ADEC is implementing 18 AAC 50.077. This regulation is broader than just new construction; by regulating at the point of sale any new installation, including installation in existing homes, is affected. 18 AAC 50.077(a) includes a general prohibition on the installation of wood fired heating devices within the area, with exceptions defined in subsequent sections. No outdoor hydronic heaters may be sold or installed unless pellet fueled. 18 AAC 50.077(b) identifies 0.10 lb/MMBtu as the emission rate used as a requirement for pellet fueled hydronic heaters, that EPA certification is required, and that the certification from EPA will be reviewed by ADEC and only approved if the underlying certification test results are accepted. 18 AAC 50.077(c) identifies 2.0 g/hr as the emission rate used as a requirement for cordwood stoves and pellet fueled stoves, an additional emission requirement that the 1-hr filter pull shall not exceed 6.0 g/hr, that EPA certification is required, and that the certification from EPA will be reviewed by ADEC and only approved if the underlying certification test results are accepted. 18 AAC 50.077(d) identifies 2.0 g/hr as the emission rate for wood-fired heating devices whose rated size is 350,000 Btu/hr or greater, that EPA certification is required, and that the certification from EPA will be reviewed by ADEC and only approved if the underlying certification test results are accepted. 18 AAC 50.077(e) allows ADEC to review manufacturer test results and place a model on ADEC's list of devices, which identifies devices that are allowable under 18 AAC 50.077

18 AAC 50.077 is more stringent than current EPA certification for cordwood stoves because the emission limit is set at 2.0 g/hr, regardless of test method. EPA Step 2 certification has an emission limit of 2.5 g/hr for cordwood stoves that are certified with ASTM 3053, a.k.a. the cordwood method. 18 AAC 50.077 is more stringent than current EPA certification for cordwood and pellet stoves because of the additional emission limit on the 1-hr filter pull of 6.0 g/hr. EPA Step 2 certification has no limit on the 1-hr filter pull. 18 AAC 50.077 also requires

another layer of oversight and report review by requiring that ADEC perform certification reviews.

Preliminary review of the certification reports shows:

Pellet Appliances	
Number of reports reviewed	79
Number of appliances disapproved due to 2.0 g/hr emission limit	0
Number of appliances disapproved due to 1 hr filter pull (missing or over limit)	12
Number of reports with deficiencies	79
Number of approved reports	0
Number of flagged issues with reports	1,319

Cordwood Appliances	
Number of reports reviewed	128
Number of appliances disapproved due to 2.0 g/hr emission limit	9
Number of appliances disapproved due to 1 hr filter pull (missing or over limit)	52
Number of reports with deficiencies	128
Number of approved reports	0
Number of flagged issues with reports	2,658

Although the list of approved devices will change as manufacturers submit additional information, with some appliances ultimately being approved for sale, 18 AAC 50.077 provides regulatory requirements limiting the type of new appliances to only the cleanest appliances available. As noted previously, 18 AAC 50.077(j)(2) does prevent the installation of wood heaters as the sole source of heat in new construction in the area with a minor exception, but prescribing requirements on the primary source of heat in structures is a much broader restriction related to building and land use.

Additionally, ADEC has no land use authority to impose restrictions on new construction. By state statute, land use authority is reserved to local governments: AS 29.40. Therefore, the only feasible method to implement this measure is by regulating at the point of sale by limiting the appliances to those with the lowest emissions, which also allows residents to adequately back up heating systems.

Conclusion

ADEC lacks the land use authority required to implement this measure, and the measure as written contains no provisions for back-up heating requirements, therefore it is technologically infeasible to implement as written and cannot be considered as a measure for the 2020 Amendment to the Serious SIP. 18 AAC 50.077 is the only technologically feasible method to implement this measure and was adopted with the Serious Area SIP and is considered equivalent to the Bay Area measure.

Measure 9: Limit the Density of Solid Fuel Heating Devices in New Construction

Implementing Jurisdiction(s)

- San Joaquin Valley APCD, Eastern Kern APCD

Regulation Weblink(s)

- https://www.valleyair.org/rules/currntrules/r4901.pdf
- http://www.kernair.org/Rule%20Book/4%20Prohibitions/416_1%20Wood%20Burning%20Heaters%20and%20Fireplaces.pdf

Background

The San Joaquin Valley Air Pollution Control District in California limits the number of wood burning heaters allowed in new residential developments. Two limits apply to developments with housing densities greater than 2 residences per acre: no wood burning fireplaces may be installed in these residences, and no more than two U.S. EPA Phase II-certified wood heaters may be installed per acre in these residences. For developments with housing densities less than or equal to two residences per acre, the regulation allows no more than one wood burning fireplace or U.S. EPA Phase II-certified wood heater per residence. (Section 4901.5.3.2)

The Eastern Kern Air Pollution Control District in California prohibits the installation of wood burning fireplaces in new residential subdivisions that consist of 10 or more dwellings. (Section 416.1.VI)

Fairbanks allowed for the installation of solid fuel burning devices in new construction provided that permits had been issued by the Borough, devices were Borough-listed, and installation was performed by a Borough-listed installer, among other requirements. These regulations were removed after passage of the Home Heating Reclamation Act.

Analysis

Alaska DEC does not have the information or programs to address land use authority required to limit the number of solid fuel burning devices that can be installed in single dwellings newly constructed, nor limit the number of devices that can be installed per acre in new residential developments. Multiple years would be required for DEC to gather data and evaluate options, possibly obtain necessary authority, and establish the regulatory requirements to implement this measure. Instead, DEC has regulated wood heater installation so that no new structure may have wood as its sole source of heat (18 AAC 50.077(j)).

Additionally, ADEC has no land use authority to impose restrictions on new construction. By state statute, land use authority is reserved to local governments: AS 29.40.

Conclusion

ADEC lacks the land use authority required to implement this measure, therefore it is technologically infeasible and cannot be considered as a measure in the 2020 Amendment to the Serious SIP.

Measure 10: Install EPA-Certified Device Whenever a Fireplace or Chimney is Remodeled

Implementing Jurisdiction(s)

- Bay Area AQMD

Regulation Weblink(s)

- https://www.baaqmd.gov/~/media/dotgov/files/rules/reg-6-rule-3-woodburning-devices/documents/rg0603.pdf?la=en

Background

The Bay Area AQMD requires that a gas-fueled, electric, or EPA-certified device be installed whenever a fireplace or chimney is remodeled at a cost that exceeds $15,000 and requires a local building permit (Section 6-3-307).

Fairbanks limited wood heating devices in new construction to Borough-listed appliances (Section 21.28.030E) but did not require the replacement of non-Borough-listed appliances with listed versions upon the remodeling of a residence or of a fireplace or chimney. These regulations were removed after passage of the Home Heating Reclamation Act.

Analysis

The Bay Area AQMD measure would require the upgrading of wood heating appliances in affected Borough residences in which remodeling projects included fireplace or chimney modifications that exceeded $15,000 in cost. Alaska DEC does not have the information or programs to address land use/building code authority needed to govern building/remodeling permits. Multiple years would be required for DEC to gather data and evaluate options, possibly obtain necessary authority, and establish the regulatory requirements to implement this measure.

Additionally, ADEC has no land use authority to impose restrictions on new construction. By state statute, land use authority is reserved to local governments: AS 29.40.

Conclusion

ADEC lacks land the land use authority required to implement this measure; therefore, it is technologically infeasible and cannot be considered as a measure for the 2020 Amendment to the Serious SIP.

Measure 11: Prohibit Use of Rain Caps on Stacks

Implementing Jurisdiction(s)

- State of Maine

Regulation Weblink(s)

- https://www1.maine.gov/sos/cec/rules/06/096/096c150.doc

Background

Outdoor wood boilers (OWBs) are generally used to provide heat for residential structures. Firewood is burned in the unit, sited outside the residence, with the energy released by combustion transferred to the residence through circulation of a thermal fluid.

In some locations, operators of outdoor wood boilers attach a rain cap (or weather cap) to the stack from which emissions produced by the outdoor wood boiler are released. This rain cap is attached to prevent moisture (rain, snow, etc.) from entering the stack during periods of non-operation and causing exposed surfaces to rust.

Analysis

The BACM analysis of this measure is unchanged - Maine is the only jurisdiction that currently enforces a regulation related to the use of rain caps on outdoor wood boiler stacks, prohibiting the installation of caps unless specifically required by the manufacturer of the boiler.[32] Personal communications with staff members of the Maine Department of Environmental Protection indicated that the regulation was adopted in Maine between 2007 and 2008 primarily in response to complaints from citizens about the use of boilers by neighbors.[33] More than one staff member indicated that no scientific or statistical analysis was conducted by the staff during development of the regulation. One said specifically that he "did not know if the rule had worked well," and one said that only one comment was entered into testimony in the meeting at which the Maine DEQ Board adopted the regulation; the only responsive in the record mentioned that the use of a rain cap impeded buoyant plume rise of smoke exiting a stack and resulted in higher ground-interior level impacts at downwind residences. [34]

The average precipitation rate in Fairbanks is much lower than that of Maine, particularly in the winter months. Whereas Maine averages more than forty inches of precipitation per year,

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[32] Regulation can be downloaded at http://www.maine.gov/dep/air/woodsmoke/woodcombustion.html

[33] Personal communication on October 4, 2017 with Jeff Crawford, Air Bureau, Maine Department of Environmental Protection; Personal communication on October 5, 2017 with Tom Graham, Air Bureau, Maine Department of Environmental Protection.

[34] Personal communication on October 4, 2017 with Jeff Crawford, Air Bureau, Maine Department of Environmental Protection; Personal communication on October 5, 2017 with Tom Graham, Air Bureau, Maine Department of Environmental Protection.

Fairbanks averages less than eleven.[35,36] In addition, whereas ~54%, or 22 inches, of Maine's precipitation falls during the winter nonattainment months (October through March), only 31%, or 3 inches, of precipitation in Fairbanks falls during those months. Discussions with Fairbanks North Star Borough Air Quality Program staff found that rain caps are not used in Fairbanks, and thus a regulation prohibiting rain caps would have no impact on emissions.[37]

Conclusion

The BACM conclusion is unchanged - the prohibition of rain caps by Maine DEC was intended to improve smoke dispersion, not reduce emissions. Because of the very low inversion heights that are experienced in Fairbanks during the winter heating season, a prohibition of rain caps would not improve plume dispersion in the vertical direction, much less reduce emissions. Since the need for rain caps in Fairbanks is limited and Borough staff have previously indicated that existing OWBs are not equipped with them, a regulation prohibiting rain caps on OWB stacks would produce no emission benefit and is therefore technologically infeasible and not eligible for consideration as a control measure for the 2020 Amendment to the Serious SIP.

Measure 12: Require Minimum Stack Height for OWBs Relative to Nearby Rooflines

Applicable Jurisdiction(s)

- State of Maine

Regulation Weblink(s)

- http://www.maine.gov/dep/air/woodsmoke/woodcombustion.html

Background

Outdoor wood boilers (OWBs) are generally used to provide heat for residential structures. Firewood is burned in the unit, located outside the residence, with the energy released by the combustion process transferred into the interior of the residence through circulation of a thermal fluid.

The boilers generate emissions by the combustion of wood fuel, and those emissions can be transported to impact neighboring residences. Ground-level concentrations of emissions at downwind residences can be influenced by the heights at which emissions exit exhaust stacks and whether wind flows at exit points are impacted by the heights of structures near these exhaust stacks.[38]

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35 Data collected for Portland, ME; Augusta, ME; and Lewiston, ME from U.S. Climate Data at https://www.usclimatedata.com/climate/maine/united-states/3189; Accessed 10/12/2017.
36 Data collected for Fairbanks, AK from U.S. Climate Data at https://www.usclimatedata.com/climate/fairbanks/alaska/united-states/usak0083; Accessed 10/12/2017.
37 Personal communication with Todd Thompson, Fairbanks Borough Air Quality Department, October 10, 2017.
38 Minnesota Pollution Control Agency, AERMOD Evaluation of Outdoor Wood Boiler Stack Height and Setback

Maine is the only state that currently regulates the minimum height of exhaust stacks serving newly-installed OWBs. The regulation specifies a minimum stack height of ten feet or "two feet higher than the peak of the roof of the structure being served by the OWB" if:

1) the OWB has a particulate emission rating greater than 0.60 lbs/MMBtu and is within 500 feet of any nearby residence, or
2) the OWB has a particulate emission rating of 0.60 lbs/MMBtu or less and is within 300 feet of any nearby residence.[39]

Additionally, the regulation requires the extension of an existing OWB exhaust stack if a new residence is constructed within the setback distances specified in the regulation.

Analysis

The BACM analysis of this measure is unchanged - as with the Maine-only regulation prohibiting the use of rain caps on OWB exhaust stacks, staff members of the Maine Department of Environmental Protection reported that the regulation was adopted in Maine between 2007 and 2008 primarily in response to nuisance complaints from citizens about the use of OWB by neighbors.[40] More than one staff member indicated that no scientific or statistical analysis was conducted by the staff during development of the regulation to estimate its benefits. One said specifically that he "did not know if the rule had worked well," and one said that no public comments were received in relation to the stack height requirements prior to or during the public hearing at which the Maine DEQ Board adopted the regulation.

Maine adopted this rule to minimize disputes between neighbors; the rule has no effect on emissions and was not developed to reduce ambient $PM_{2.5}$ concentrations other than at nearby downwind residences. The rule predates federal regulation of OWBs, which mandates that owner manuals provide "guidance on proper installation information, including stack height".[41] A survey of owner manuals found installation instructions specifying that chimney height extend above the roofs of surrounding buildings. [42] Industry guidance contained in Best Burn Practice for Wood Burning Outdoor Furnace recommends that stack extend 2 feet above surrounding roof top peaks.[43]

[39] Regulation can be downloaded at http://www.maine.gov/dep/air/woodsmoke/woodcombustion.html
[40] Personal communication on October 4, 2017 with Jeff Crawford, Air Bureau, Maine Department of Environmental Protection; Personal communication on October 5, 2017 with Tom Graham, Air Bureau, Maine Department of Environmental Protection.
[41] https://www.federalregister.gov/documents/2015/03/16/2015-03733/standards-of-performance-for-new-residential-wood-heaters-new-residential-hydronic-heaters-and
[42] https://centralboiler.com/media/1803/9000166_manual_classic_27-jan-2014.pdf
[43] https://www.hpba.org/Portals/26/Documents/Government%20Affairs/NSPS%20Members/HPBA%202014%20NSPS/Attachment13TechEnvironmentalAirDispersionModelingReportofEClassic2300July2012.PDF?ver=2016-11-21-105529-197

The addition of a regulation specifying minimum stack heights for OWBs would not lead to a reduction in $PM_{2.5}$ emissions but could reduce $PM_{2.5}$ concentrations downwind of newly-installed OWBs or newly-constructed residences near OWBs.

Conclusion

The BACM conclusion is unchanged - because of the lack of any emission reduction resulting from adoption of a minimum stack height regulation, this measure is technologically infeasible and not eligible for consideration as a control measure for the 2020 Amendment to the Serious SIP.

Measure 14: Require Installation of Thermal Mass to Improve Efficiency and Prevent Frequent Cycling in Selected New Units

Implementing Jurisdiction(s)

- None

Regulation Weblink(s)

- None

Background

The initial review of applicable SIPs and EPA guidance documents mistakenly identified a measure requiring the installation of thermal mass to prevent frequent burn cycling in hydronic heaters.

Analysis

The BACM analysis of this measure is unchanged - a review of the literature, applicable SIPs, EPA guidance documents, hydronic heater certification documents and the final rule for hydronic heaters issued in 2015 (Standards of Performance for New Residential Wood Heaters, New Residential Hydronic Heaters and Forced-Air Furnaces)[44] could find no requirements for installing thermal mass in hydronic heaters. The final rule for hydronic heaters and forced air furnaces discussed concerns about cycling conditions, operations, etc., but included no requirement for the addition of thermal mass to reduce cycling. The limited detail provided with this measure, along with the findings of the literature review, do not support any quantifiable permanent and enforceable emission reductions.

Conclusion

The BACM conclusion is unchanged - 40 CFR 51.100 defines BACM as a control measure that "generally can achieve greater permanent and enforceable emission reductions … than can be

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[44] https://www.gpo.gov/fdsys/pkg/FR-2015-03-16/pdf/2015-03733.pdf

achieved through implementation of RACM." This measure cannot achieve permanent and enforceable emission reductions greater than can be achieved through implementation of RACM, does not meet the definition of BACM and is dismissed from consideration as control measure for the 2020 Amendment to the Serious SIP.

Measure 18: No Visible Emissions during Curtailment Periods

Applicable Jurisdiction(s)

- Maricopa County, Arizona

Regulation Weblink(s)

https://www.maricopa.gov/DocumentCenter/View/2016/P-26---Residential-Woodburning-Restriction-Ordinance-PDF

Background

A Maricopa County ordinance[45] allows wood stoves certified as the sole source of heat in a residential dwelling to continue operating during curtailment periods provided that these stoves emit no visible emissions, i.e. 0% opacity. Most other jurisdictions with wood burning regulations limit visible emissions from wood stoves permitted to operate during curtailment periods to 20% opacity.

Communication with staff members from Maricopa County's Air Quality Department indicated that no staff report was prepared when the "no visible emission" regulation was first adopted in 1994.[46] Communication with a staff member from Montana's Department of Environmental Quality indicated that Montana, where ambient temperatures during the winter nonattainment season can drop to low levels that approach those in Fairbanks, maintains a restriction that allows visibility up to 20%.[47] Historical EPA literature states that "It can be difficult to distinguish pollutant-containing mists from innocuous water droplets that are generated from steam condensation,"[48] and advises inspectors that "if the temperature is low...consider the possibility of a steam plume that does not evaporate easily."[49] Academic literature summarizing EPA's Method 9 states:

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[45] Ordinance P-26, Section 3.C.1 of Maricopa County Ordinance P-26: Residential Woodburning Restriction, available at https://www.maricopa.gov/DocumentCenter/View/5332; accessed October 12, 2017.
[46] Personal communication with Johann Kuspert, Maricopa County Air Quality Department, September 28, 2017.
[47] Personal communication with Benjamin Schmidt, Montana Department of Environmental Quality, October 6, 2017.
[48] Rose, Thomas H, Visible Emission Evaluation Procedures Course Student Manual APT/ Course 325 Final Review Draft, 1995, available at https://www3.epa.gov/ttnemc01/methods/VECourse.pdf; accessed October 12, 2017.
[49] Eastern Technical Associates and Entrophy Environmentalist, Inc., Visible Emissions Field Manual EPA Methods 9 and 22, EPA 340/1-92-004, 1993, available at https://www3.epa.gov/ttnemc01/methods/VEFieldManual.pdf; accessed 10-12-2017

> In cold weather, steam is often a part of the emission. In order to make an accurate reading, opacity must be read after the steam has dissipated. This change is readily visible as the apparent opacity will drop significantly but stay constant after that.[50]

Analysis

The BACM analysis of this measure is unchanged - two additional considerations in Fairbanks are that (1) daylight is limited during winter months to no more than 5 hours/day in December, January and February, the period when elevated $PM_{2.5}$ concentrations are most likely to occur, and (2) oil- and gas-fired heating devices generate condensing moisture plumes but are not required to cease operation during curtailment periods. These factors have led the Borough in the past to develop a checklist of considerations to differentiate between wood/coal stoves and oil/gas furnaces. These considerations include:

- Odor – smelling the smoke is often the first and best indication of wood or coal burning;
- Multiple Stacks – frequently an indication of a secondary heating device besides a furnace;
- Location of Stack – stacks located over a garage connected to the house is typically for an oil/gas furnace; stacks over separated garages and sheds/shops is an indication of a SFBD; stacks located above a common area, such as a living room, are an indication of a SFBD;
- Black Soot around Stack – black residue over snow & around stacks indicates solid fuel burning;
- Dark or Colored Smoke – darker colored smoke can be an indication of low temperature wood burning and coal burning;
- Cycling Smoke Plumes – an abrupt change in the plume is an indication of an oil/gas furnace;
- Piles or Stacked Cut Wood – are a clear indication of a wood burning device;
- Exterior chutes – are an indication of a coal burning device;
- Property Database Check – the Borough's database can provide information on original installations, Deed Restrictions, etc.

This checklist allowed Borough field personnel to efficiently determine whether plumes are coming from homes violating Stage 1 or Stage 2 Alerts. Borough personnel were able to survey 40 homes per day during a 5-hour shift (8 homes per hour) to determine compliance with Stage 1 or Stage 2 Alerts. Compliance was determined by observing a SFBD in operation, without the need for an opacity observation. Opacity observations during stage restrictions would add the problem of differentiating steam from particles, compounding the previously identified difficulties of limited daylight and differentiating from oil and gas fired heating devices. A reduction in the limit to zero visibility would require any field staff to monitor each home for a minimum of 20 minutes to identify if a continuous plume with decreasing opacity represents a wood-fired device during startup, and to record the minimum number of observations required

[50] University of Nebraska-Lincoln, Safe Operating Procedure: Opacity of Emissions from Combustion Sources and Operating Log Record, 2017, available at https://ehs.unl.edu/sop/s-opacity_emissions.pdf; accessed October 12, 2017.

by EPA Method 9. Enforcing a zero opacity standard during curtailment would limit the number of homes observed per hour to 2 or less (20+ minutes opacity reading time plus travel time, identification of stacks, etc.). The reduction in the number of homes observed would significantly reduce the identification of Alert violations and benefits of the enforcement program. As a result, implementation of this measure would result in increased emissions during curtailment periods as fewer homes would be inspected for compliance. Fairbanks is no longer enforcing this measure because of the passage of the Home Heating Reclamation Act. While the state is now enforcing this measure under the Episode Chapter of the $PM_{2.5}$ Serious SIP, the same issues noted above apply as the implementation of the measure would lead to a reduction in the number of homes inspected for compliance.

Conclusion

The BACM conclusion for this measure is unchanged. It is technologically infeasible because a more stringent visibility standard would reduce the number of homes inspected, reduce the number of violations identified and allow for an increase in wood burning emissions. Therefore, this measure is not eligible for consideration as a control measure for the 2020 Amendment to the Serious SIP.

Measure 20: Require Renewals with Inspection Requirements

Implementing Jurisdiction(s)

- San Joaquin Valley APCD

Regulation Weblink(s)

- https://www.valleyair.org/rules/currntrules/r4901.pdf

Background

San Joaquin Valley APCD prohibits wood-fired heating devices from being operated during a Level One Episodic Wood Burning Curtailment except for USEPA Phase II certified devices and pellet stoves, provided that these are registered with the District (Rule 4901 Section 5.6.1). Qualifying wood heaters are eligible for registration by submitting a completed application and supplemental documentation to the District including certification by a District Registered Wood Burning Heater Professional that the device is either a Phase II certified device or a pellet stove (Section 5.9.2.1). If the device for which registration is being sought is more than one year old at the time of initial registration, the application for registration much include proof of inspection by a Registered Professional (Section 5.9.2.1.3). In areas where natural gas service is not available, registration is not required for a device to be operated during a Burning Curtailment.

Registrations are valid for a period of up to three years. Registration may be renewed by submitting a Registration Renewal application with verification that the wood burning device has been inspected by a Registered Professional to verity that it is maintained pursuant to manufacturer specifications (Section 5.10.3).

Fairbanks allowed Borough-listed devices to continue operating during a Stage 1 air alert if such devices had approved Stage 1 waivers. Borough-listed devices included USEPA Phase II certified wood stoves, USEPA certified hydronic heaters, masonry heaters, cook stoves, or other devices emitting 2.5 gm/hr or less as documented by accepted testing. Stage 1 waivers did not have expiration dates. These regulations were removed after passage of the Home Heating Reclamation Act.

EPA commented that the Fairbanks requirements lacked the regular renewal and inspection opportunities to verify proper device operation.

Analysis

All three agencies require the registration or permitting of wood heating devices in order to be operated during burning curtailment periods. Adopted in the Serious Area SIP, 18 AAC 50.077(h) requires all wood fired-heating devices to be registered when applying for any waivers described in the State Air Quality Control plan. The Episode Chapter of that document details the requirement for the issuance of a waiver and the related renewal and inspection requirements separately for related application, renewal and inspection requirements for all solid-fuel heating devices. All devices require an initial inspection/maintenance verification by either the owner or a professional installer. All devices with an emissions rating of >7.5 g/hr are only eligible for 2 annual NOASH waivers. Devices with an emission rating of >7.5 g/hr are not allowed a Stage 1 waiver. Lower emitting devices are eligible for longer NOASH or Stage 1 waiver periods (up to 2, 3 and 4-years). These requirements are consistent with those specified in San Joaquin Valley and address EPA's comments.

Another difference between the regulations is that San Joaquin Valley's wood burning control season applies to the months of November through February (4901 Section 3.30) while Fairbanks wood burning season applies to the months of October through March (18 AAC 50.076(b). Fairbanks wood burning controls apply for a 6-month period, while San Joaquin Valley's controls apply for a 4-month period. The difference in wood burning control periods more than compensates for any differences in waiver periods.

Conclusion

The adoption of the referenced Episode Chapter requirements and state regulations are sufficient to meet the 2020 Amendment Plan requirements of this measure, therefore the measure is technologically feasible, implemented in an alternate/equivalent form, and no additional analysis is required.

Measure 23: Require Exempt Households to Display a Decal Visible from a Point of Public Accesss

Implementing Jurisdiction(s)

- Ada County, Idaho

Regulation Weblink(s)

- http://www.sterlingcodifiers.com/codebook/index.php?book_id=447

Background

The Ada County Development Services Department exempts NOASH households and Department-listed low emission wood heating devices from having to cease operation during curtailment periods (Section 5-10-8.A). One of the requirements for a valid exemption is that each affected household display an exemption decal visible from a point of public access.

Previously, the Borough prepared lists of residences registered as NOASH households and those heated with Borough-approved appliances. These lists were used by Borough enforcement staff in the field to identify such residences during Stage 1 Alert periods as exempt from wood burning curtailment requirements. The authority for the Borough to assemble these lists disappeared with the passage of the Home Heating Reclamation Act and ADEC maintains and updates these lists as it implements the curtailment program.

Analysis

The BACM analysis of this measure is unchanged - the Ada County measure is intended to facilitate field compliance inspections by highlighting non-exempt residences with visible smoke plumes for enforcement actions. Because of the high prevalence of oil heaters in all Borough residences (79.0%), determination of compliance with curtailment requirements requires a minimum of 20-minute opacity observations – except in the case of NOASH residences - to ascertain oil versus wood fuel sources of visible emissions. Determination of compliance at NOASH residences, which constitute only 2.2% of residences in the nonattainment area, can be ascertained as quickly by examination of a list of NOASH addresses as by observation of a visible decal. Moreover, the Borough prepared lists of residences have been made available to state enforcement staff and are being used to identify registered NOASH residences using tablets with maps noting their locations. The adoption of decals will add no benefit to current enforcement efforts.

Conclusion

The BACM conclusion is unchanged - the adoption of a visible decal regulation will not provide an emissions reduction benefit during Stage 1 Alerts and, thus, is not technologically feasible. Therefore, this measure is not available for consideration as a control measure for the 2020 Amendment to the Serious SIP.

Measure 25: Require Detailed Application or Inspection to Verify Need for No Other Adequate Source of Heat (NOASH) Permit

Implementing Jurisdiction(s)

- Puget Sound Clean Air Agency (PSCAA)

Regulation Weblink(s)

- http://www.pscleanair.org/219/PSCAA-Regulations

Background

The Puget Sound Clean Air Agency (PSCAA) exempts households with no other adequate source of heat (NOASH) from curtailment requirements if the residences or commercial buildings were constructed prior to July 1, 1992 and not substantially remodeled after that date, and the households have been granted exemptions by the agency (Section 13.05.d.1.a). PSCAA grants NOASH exemption only after receipt and review of a detailed application form.[51]

Fairbanks previously exempted NOASH households from having to cease burning wood during Stage 1 Alerts provided that such households have registered with the Borough. The Borough granted NOASH determinations only after receipt and review of detailed application form that must be notarized before submittal.[52] Regulations mandating these Borough requirements were removed after passage of the Home Heating Reclamation Act and the implementation of the Alert and waiver programs is now implemented by ADEC.

As noted earlier, EPA commented that the Fairbanks requirements lacked the regular renewal and inspection opportunities to verify proper device operation.

Analysis

The Episode Chapter of the $PM_{2.5}$ Serious SIP noted in the introduction details of Alaska's exception and waiver requirements including:

- Length of waivers based on age and emission rate of the device
- Annual renewals on oldest and highest emission rated devices
- 3rd party inspection of device to verify proper installation required
- 3rd party inspection of maintenance (chimney sweep) required
- Device registration required
- Documentation of dry wood required

Exceptions/Waiver levels are detailed in Tables for Stage 1 and Stage 2 Alerts. The structure is intended to provide incentives to upgrade existing devices while at the same time acknowledging the number of devices already changed out as part of the wood stove change out program. A

[51] Personal communication between Amy Warren, PSCAA, and Meena Rezaei, Trinity Consultants, on December 15, 2017. Application available for download at: http://www.pscleanair.org/DocumentCenter/View/163; accessed on January 14, 2018.
[52] Application was for download at: http://fnsb.us/transportation/Pages/Change-Out-Program.aspx; accessed on January 14, 2018

detailed application and verification documentation is required prior to issuance of any exception or waiver.

These requirements are consistent with PSCAA NOASH curtailment and application requirements and address EPA comments about renewal and inspection opportunities to verify proper device operation.

Conclusion

The adoption of the referenced Episode Chapter requirements are sufficient to meet the plan requirements of this measure, therefore the measure is technologically feasible, has been adopted and implemented in alternate form, and no additional analysis is required for the 2020 Amendment.

Measure 27: Require Annual Renewal of Waiver

Implementing Jurisdiction(s)

- Maricopa County

Regulation Weblink(s)

https://www.maricopa.gov/DocumentCenter/View/2016/P-26---Residential-Woodburning-Restriction-Ordinance-PDF

Background

Maricopa County AZ requires that residential sole source of heat (NOASH) permits be renewed annually (Ordinance P-26, Section 4.A). This regulation is intended to annually confirm compliance of the permitted household with NOASH requirements and minimize the number of permits issued to non-compliant households. Section 4.A also prohibits the initial issuance of a NOASH permit after December 31, 1995, and allows for annual permit renewal if the initial permit was issued before December 31, 1995, and the household and device continue to meet permit requirements.

Fairbanks required that NOASH households apply and be approved in order to continue burning during curtailment periods. NOASH designations were valid for one year and required renewal to remain valid.[53] The Borough regulations were removed with the passage of the Home Heating Reclamation Act.

[53] Personal communication between Nicholas Czarnecki, FNSB Air Quality Division, and Bob Dulla, Trinity Consultants, on December 19, 2017.

Analysis

The exception and renewal requirements for NOASH waivers are specified in the Episode Chapter of the $PM_{2.5}$ Serious SIP. It mandates that all registrations require verification by certified installers. Renewal requirements vary by age, control technology and emission rating. Higher emitting devices older than 10 years are limited to 2 annual renewals. Thus, pre-2010 higher emitting devices are only allowed 2 renewals. Longer renewal periods are allowed for lower emitting devices. Maricopa does not limit the number of renewals for devices installed prior to December 31, 1995. Also, 18 AAC 50.077(a) requires that a person may not install, reinstall, sell, lease, distribute, or convey wood-fired heating devices that lack a valid EPA certification under 40 C.F.R. 60.533 or any wood-fired outdoor hydronic heaters, except pellet fueled devices. This requirement ensures rapid turnover of the existing stock of older, higher emitting wood-burning devices over the next 5 years, whereas the Maricopa regulation relies on a much slower turnover of pre 1996 wood-burning devices, while providing no incentive to retire post 1995 wood burning devices. Thus, the older Maricopa NOASH devices can continue to operate into the future, whereas in Alaska those devices (and many more) are required to be rendered permanently inoperable by December 31, 2024.

Collectively, the new Alaska regulations provide greater emission reductions than would be produced by the adoption of Measure 27.

Conclusion

The adoption of the referenced Episode Chapter requirements and state regulations are sufficient to meet the plan requirements of this measure, therefore the measure is technologically feasible, adopted and implemented in alternate form, and no additional analysis is required.

Measure 28: Set Income Threshold [for Curtailment Exemption]

Implementing Jurisdiction(s)

- Missoula MT; Maricopa County AZ

Regulation Weblink(s)

- https://www.missoulacounty.us/home/showdocument?id=8452

https://www.maricopa.gov/DocumentCenter/View/2016/P-26---Residential-Woodburning-Restriction-Ordinance-PDF

Background

The Missoula City-County Air Pollution Control Program exempts households qualifying for energy assistance from burning curtailment requirements (Section 9.207). Maricopa County grants temporary exemptions from curtailment requirements to households qualifying for energy assistance (Section 4.B).

Fairbanks did not exempt households from curtailment requirements solely on the basis of income, but did allow the granting of sole-source-of-heat exemptions to households in which "economic hardships require the applicant's use of a solid fuel burning appliance" provided that the appliance is Borough-listed, in addition to other requirements. The Borough regulations were removed with the passage of the Home Heating Reclamation Act.

Analysis

The Missoula City-County measure allows low income households to continue burning during curtailment periods. While Alaska will also allow low income households to continue burning during curtailment periods (per the Episode Chapter of the $PM_{2.5}$ Serious SIP), NOASH exceptions/waivers are not exempt from the restrictions noted above in Measure 27. This means the pool of NOASH waivers will become increasingly cleaner (i.e., lower emitting) over the next 5 years. At this point, Alaska has established the economic hardship thresholds for NOASH waivers, consistent with the previous Borough thresholds, economic hardships must provide documentation of enrollment in one of several assistance programs. 2020 amendments to the Episode Chapter include defining the specific programs that qualify for economic hardship. Suitable documentation of economic hardship must include receipt of assistance for: unemployment, Denali Kid Care, WIC, or social security/disability.

Overall, the removal or permanent inoperability requirements of 18 AAC 70.077(a) & (l) will result in greater emission reductions in the near term than any differences in the definition of economic hardship and is therefore more stringent.

Conclusion

The adoption of the 2020 amendments to the Episode Chapter requirements and state regulations are sufficient to meet the plan requirements of this measure, therefore the measure is technologically feasible, adopted and implemented, and no additional analysis is required.

Measure 29: Allow Only NOASH Households to Burn During Curtailment Periods

Implementing Jurisdiction(s)

- Utah Department of Environmental Quality

Regulation Weblink(s)

- https://rules.utah.gov/publicat/code/r307/r307-302.htm

Background

The Utah Department of Environmental Quality exempts only households with no other adequate source of heat (NOASH) from the requirement to cease operation of wood heating devices during curtailment periods in $PM_{2.5}$ nonattainment areas in the state (Section R307-302-3.4).

Fairbanks exempted households with NOASH waivers, wood burning appliances with Stage 1 waivers, and wood burning appliances in households affected by power failures from similar curtailment requirements during Stage 1 Alerts. The Borough regulations were removed following the approval of the Home Heating Reclamation Act, however the State regulations remain in place. The State waiver program has mirrored the Borough program.

Analysis

Utah calls burn bans when concentrations are forecast to reach or exceed 25 $\mu g/m^3$. Alaska's Episode Chapter of the $PM_{2.5}$ Serious SIP calls Stage 1 Alerts when concentrations are forecast to exceed 20 $\mu g/m^3$ and Stage 2 Alerts when concentrations are forecast to exceed 30 □g/m^3. During a Stage 1 Alert those with a NOASH or a Stage 1 waiver may continue to operate wood heating devices. During a Stage 2 Alert only those with a NOASH may continue to operate wood heating devices. Section III.D.7.12 Emergency Episode Plan contains the detailed breakdown of the criteria and length requirements for temporary NOASH exceptions/waivers and temporary Stage 1 waivers. During the 2019/2020 winter season, as shown in Table 6, ADEC called a total of 24 Stage 1 Alerts (15 in North Pole and 9 in Fairbanks) and 34 Stage 2 Alerts (25 in North Pole and 9 in Fairbanks)

Table 6. Number of Stage restrictions called by ADEC during 2019/2020 heating season

Number of Alert Restrictions Called	Stage 1	Stage 2
North Pole:	15	25
Fairbanks:	9	9
Total:	24	34

During the 2019/2020 winter season, as shown in Table 6, ADEC issued a total of 51 NOASH waivers and 25 Stage 1 waivers.

Table 7. Burn restriction waivers issued by DEC during 2019/2020 heating season

Burn Restriction Waivers Issued	
DEC NOASH Waivers:	51
DEC Stage 1 Waivers:	25
Total:	76

By lowering the Stage 2 threshold to be equivalent with Utah's NOASH only threshold of 25 $\mu g/m^3$ the near term emission reductions would only result from Stage 1 wood heating devices ceasing operation, because all other wood burning appliances are required to cease operation at the Stage 1 level of 20 $\mu g/m^3$. Comparing the number of Stage 1 waivers issued in the 2019/2020 heating season to the 2019 emission inventory estimates of wood heating devices, there were 25 Stage 1 Waivers and approximately 13,899 SFBAs, Stage 1 waivers accounted for approximately 0.2% of the inventory of SFBAs. Any near-term benefits for lowering the Stage 2 threshold to 25 $\mu g/m^3$ would be negligible.

Implementing a curtailment threshold at 20 $\mu g/m^3$ that applies to all but 0.2% of the estimated inventory is more stringent than implementing a single stage threshold to 25 $\mu g/m^3$. Therefore, at the present time, ADEC's two stage thresholds are more stringent than Utah's one stage threshold.

ADEC recognizes that this analysis is not static; for example, as the number of Stage 1 waivers grow the potential benefits of this measure will increase. Likewise, as the North Pole monitor moves closer to attainment, the number of Stage 1 alerts may also increase in proportion to Stage 2 alerts. The low percentage of Stage 1 waivers compared to the estimated 2019 inventory of appliances is also not fully understood. However, as the curtailment program becomes a cultural norm in Fairbanks, participation in the Stage 1 program and the NOASH program may rise. As the number of Stage 1 waivers rises, there may be a point where Utah's single stage curtailment at 25 $\mu g/m^3$ could be more stringent than ADEC's current two stage curtailment.

Conclusion

The adoption of the referenced Episode Chapter requirements are presently sufficient to meet the plan requirements of this measure, therefore the measure is technologically feasible, adopted and implemented, and no additional analysis is required. Recognizing that the analysis is dynamic, and changes may occur as the curtailment program becomes more widely accepted and the area moves closer to attainment, ADEC has evaluated this measure as a contingency measure for future adoption if triggered.

Measure 31: Require Sale of Only Dry Wood during Late Summer to the End of Winter

Implementing Jurisdiction(s)

- **South Coast Air Quality Management District**

Regulation Weblink(s)

- **http://www.aqmd.gov/docs/default-source/rule-book/rule-iv/rule-445.pdf**

Background

SCAQMD's Rule 445 limits the sale of commercial firewood to seasoned only firewood from July 1 through the end of February the following year. Seasoned firewood is defined to have a moisture content of 20 percent or less by weight as determined by approved hand-held moisture meters or an alternate method defined by the California Air Resources Board. Commercial wood sellers are free to sell both seasoned and non-seasoned firewood during the remaining months of the year. The goal is to restrict the supply of unseasoned wood available for use during winter months.

Fairbanks North Star Borough Code[54] and Alaska regulation did not allow burning of firewood with a moisture content exceeding 20%. The Code was modified to remove this requirement from Borough code after voter approval of the Home Heating Reclamation Act. The state regulation to burn dry wood remains in effect.

Alaska regulations[55] require mandatory registration of commercial wood sellers, the use of uniquely numbered three-part moisture disclosure forms, which document the date the wood was cut and findings of moisture measurements of three pieces of wood for each cord sold. The wood seller is required to sign the form, date when it was delivered and obtain signature of the customer purchasing the wood. The wood seller is also required to provide the customer with a copy of the signed disclosure form and submit to the state the department's copy of the completed disclosure form.

EPA commented on ADEC's Preliminary draft Serious SIP that 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)." In response, Alaska adopted regulation, 18 AAC 50.076(k) to include requirements to regulate the sale of wood in the Fairbanks Nonattainment Area. Specifically, 50.076(k)(3) states: "Except as permitted under (j) of this section, on and after October 1, 2021, a commercial wood seller required to register with the department under (d) of this section (3) shall periodically measure, using a type of commercially available moisture test meter that is approved by the department for accuracy, the moisture content of a representative sample of the wood to ensure the stock is dry prior to selling."

EPA in their comments on 2020 Amendment[56] commented that there were enforceability issues with the vague requirements to "periodically measure" the moisture content of wood for sale and recommended Alaska revise 18 AAC 50.076(k)(3) to require a specific frequency at which wood sellers are required to measure the moisture content of the seller's wood stock to ensure the stock is dry prior to selling. In response, ADEC is revising regulation 18 AAC 50.076(k)(3) by setting a frequency at monthly intervals to measure the moisture content.

Analysis

Alaska's 18 AAC 50.076 has been modified to include new subsections that effective October 1, 2021, ensure that all the wood being sold or provided has a moisture content of less than 20%, but with one exception for eight foot or longer round logs. This exception requires the wood seller to ensure the buyer has the ability to store the wood for the next season and will not use the wet wood for the season in which it is sold. Subsections (d)(e) & (g) require commercial wood sellers to register with the ADEC; (j) includes requirements to ensure that wood withless than 20% moisture content is being sold after the effective

[54] http://www.codepublishing.com/AK/FairbanksNorthStarBorough/#!/FNSBC21/FNSBC2128.html#21.28
[55] http://burnwise.alaska.gov/requirements.htm
[56] 88 Fed. Reg. at 1481; Technical Support Document: Docket No. EPA-R10-AOAR-2022-0115.

date, along with the exception. 18 AAC 50.076(l) would limit non-commercial sellers to selling dry wood. Dry wood is defined as either:

- properly seasoned, split, and stored covered for at least 9 months, unless confirmed dry;
- mechanically dried, where the drying process has been inspected and approved by the department to ensure consistency and reliability; or
- harvested from an inspected fire killed source that has been split, stacked, stored and confirmed dry prior to freezing;

Wood sellers are required to test, using a commercially available moisture test meter that the department has approved for accuracy, measure moisture content periodically to verify and ensure stock is dry prior to selling. They are also required to document the measured moisture content, and keep a record of the measurements over the seasoning period and sign an affidavit form that the department provides attesting the wood is dry prior to sale.

The new rules recognize that commercial wood sellers will need time to build up the necessary supply of dry wood required to satisfy overall firewood demand. In the intervening period, wood sellers are required to follow the regulations outlined in the background discussion.

Lacking infrastructure, such as kiln capacity sufficient to dry a season's worth of wood, the only technically feasible method of drying commercially available cordwood to less than 20% moisture content is to air dry the wood. A study of the time required to dry wood in Fairbanks found that a minimum of six summer months with covered storage is required to dry wood from spring cutting to a moisture level below 20%. However, ADEC regulation 18 AAC 50.076 (k) has set the minimum of 9 months drying time, unless confirmed, to ensure that the wood is dry given the variation in wood drying with different storage options. The same study determined that wood cut in the fall dries much more slowly and essentially stops drying once the wood becomes frozen. At this time the community lacks adequate storage space to dry the wood required to fill the commercial market. The summer of 2020 will be used by the commercial wood sellers to secure the space and construct structures to air dry the wood. Cord wood harvested during the spring of 2021 could then be stored and dried by October 2021 which is the most expeditious schedule that the commercial wood industry can follow to meet the requirements of this rule.

ADEC received a number of comments suggesting that the sale of 8-foot round logs should be allowed to continue in the future. These comments asserted that many buyers of 8-foot rounds have multi-year storage capacity and process their logs years in advance to ensure proper seasoning. ADEC recognizes that 8-foot rounds cannot be burned as is, but must be processed by the buyer so this wet wood can't be immediately burned without some up front effort. This means that buyers can't easily or unintentionally add this wood to their heating device. ADEC revised the regulations to accommodate the continued sale of 8-foot rounds, but added provisions that these sales can only occur if the wood seller confirms that the buyer will not burn wet wood in the coming season based on dry wood supply and storage/processing capacity for seasoning wood.

Recent wood sales data show that 8-foot rounds account for 20.17% of wood sales in the Fairbanks nonattainment area. The sales estimates show approximately 1,511 cords of 8-foot logs were sold compared to a total of 7,491 cords sold and is a small fraction of the cordwood consumed in the non-attainment area which is 66,217 cords per year showing that 8-foot rounds account for approximately 2.28% of cordwood consumed in the non-attainment area. The low sales volume of 8-foot rounds combined with the requirement that it cannot be burned in the coming season ensures that the year-round dry wood sales mandate for Fairbanks after October 1, 2021 more than offsets the seasonal dry wood sales requirements mandated in Measure 31; they also address EPA's comments.

EPA in their comments[57] on the 2020 Amendments, cited enforceability issues with the 18 AAC 50.076 as the requirements to measure the moisture content of wood for sale was vague. EPA recommended Alaska revise 18 AAC 50.076(k)(3) to require a specific frequency for wood sellers to measure the moisture content of the seller's wood stock. In response, ADEC is revising regulation 18 AAC 50.076(k)(3) by setting a frequency at monthly intervals to measure the moisture content.

Conclusion

The adoption of the revised state regulation addresses the enforceability issues cited by EPA and therefore meets the BACM requirements for the 2024 Amendment.

Measure 32: Require Dry Wood to be Clearly Labeled to Prohibit Marketing of Non-Dry Wood as Dry Wood

Implementing Jurisdiction(s)

- **South Coast Air Quality Management District; San Joaquin Valley Air Pollution Control District; Bay Area Air Quality Management District**

Regulation Weblinks(s)

- **http://www.aqmd.gov/docs/default-source/rule-book/rule-iv/rule-445.pdf**
- **http://www.valleyair.org/rules/currntrules/r4901.pdf**
- **https://www.baaqmd.gov/~/media/dotgov/files/rules/regulation-6-rule-3/documents/20191120_r0603_final-pdf.pdf?la=en**

Background

SCAQMD's Rule 445 limits the sale of commercial firewood to be seasoned only firewood from July 1 through the end of February the following year. Seasoned firewood is defined to have a moisture content 20 percent or less by weight as determined by approved hand held moisture meters or an alternate method defined by the California Air Resources Board. Rule 445 also contains labeling requirements:

[57] *Id.*

Effective November 4, 2013, no commercial firewood seller shall sell, offer for sale, or supply wood-based fuel without first attaching a permanently affixed indelible label to each package or providing written notice to each buyer at the time of purchase of bulk firewood that at a minimum, states the following:

Use of this and other solid fuel products may be restricted at times by law. Please check (1-877-4NO-BURN) or (www.8774NOBURN.org) before burning.

San Joaquin Valley AQMD's Rule 4901 has firewood marketing restrictions:

No person shall sell, offer for sale, or supply any wood which is orally or in writing, advertised, described, or in any way represented to be "seasoned wood" unless the wood has a moisture content of 20 percent or less by weight.

Bay Area AQMD Regulation 6 also has requirements governing the sale of wood:

Any person offering for sale, selling or providing solid fuel or wood intended for use in a wood-burning device within District boundaries shall:

Attach a label to each package of solid fuel or wood sold that states the following:

"Use of this and other solid fuels may be restricted at times by law. Please check 1-877-4-NO-BURN or http://www.8774noburn.org/ before burning."

If wood is seasoned (not to include manufactured logs), then the label must also state the following:

"This wood meets air quality regulations for moisture content to be less than 20 % (percent) by weight for cleaner burning."

Alaska regulations adopted at 18 AAC 50.076 (d),(e), & (g)[58] require mandatory registration of commercial wood sellers, the use of uniquely numbered three-part moisture disclosure forms, which document the date the wood was cut and findings of moisture measurements of three pieces of wood for each cord sold. The wood seller is required to sign the form, date when it was delivered and obtain signature of the customer purchasing the wood. The wood seller is also required to provide the customer with a copy of the signed disclosure form and submit to the state the department's copy of the completed disclosure form. The adopted regulation requires commercial wood sellers to sell only dry wood year round after October 1, 2021.

EPA in their comments[59] on 2020 Amendment had concerns similar to Measure 31 related to enforceability and dismissed the measure. ADEC is revising regulation 18 AAC 50.076(k)(1) by improving the labeling to clearly indicate "dry wood".

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58 https://dec.alaska.gov/air/anpms/sip/18aac50-reference-materials/

59 88 Fed. Reg. at 1481; Technical Support Document: Docket No. EPA-R10-AOAR-2022-0115.

Analysis

Current Alaska regulations require mandatory registration of commercial wood sellers, the use of uniquely numbered three-part moisture disclosure forms, which document the date the wood was cut and findings of moisture measurements of three pieces of wood for each cord sold. The wood seller is required to sign the form, date when it was delivered and obtain signature of the customer purchasing the wood. The wood seller is also required to provide the customer with a copy of the signed disclosure form and submit to the state the department's copy of the completed disclosure form. The state is assembling the submitted forms into an electronic database to track the moisture levels and volume of wood sold. Separate requirements address wood measurements and deliveries at temperatures below 32° F. All wood with measurements exceeding 20% is assumed to be wet.

The moisture disclosure forms require the buyer to declare:

> ***I understand that starting October 2015, only dry wood may be burned between October 1 and March 31.***

Previously, while Alaska did not require firewood to be labeled, it did require the buyer to sign a form documenting whether the wood is seasoned or unseasoned.

Current ADEC requirements are to have the customer sign a form documenting whether the wood is seasoned or unseasoned ensures that the customer has seen information about the moisture content of the wood being purchased. ADEC's requirement is more stringent than other labeling requirements which the customer may or may not see, let alone acknowledge.

While current ADEC regulations require wood sellers to document and distribute detailed information regarding the moisture content of the wood. SCAQMD Rule 445 limits the sale of commercial firewood to be seasoned only firewood from July 1 through the end of February the following year, eliminating excess emissions from commercially sold wet wood, and is therefore more stringent than current ADEC regulations.

As discussed above in the analysis of Measure 31, wood sellers currently lack the infrastructure required to dry and store a season's worth of commercial firewood. Time will be required for wood sellers to secure the space and construct the structures to air dry wood. The summer of 2020 will be the earliest opportunity for commercial wood sellers to secure the space and construct structures to air dry the wood. Cord wood harvested during the spring of 2021 could then be stored and dried by October 2021 which is the most expeditious schedule that the commercial wood industry can follow to meet the requirements of this rule.

ADEC has therefore adopted regulations in 18 AAC 50.076 (d)(e)&(g) that require commercial wood sellers to sell only dry wood year round after October 1, 2021. Subsection(j) includes requirements to ensure that wood with a less than 20% moisture content is being sold after the effective date. 18 AAC 50.076 (k) has set the minimum of 9

months drying time, unless confirmed, to ensure that the wood is dry given the variation in wood drying with different storage options. 18 AAC 50.076 (l) would limit non-commercial sellers to selling dry wood. Dry wood is defined as below 20% moisture content. Monitoring, recordkeeping, and reporting requirements are also included in the proposed regulations to ensure compliance with the 20% moisture standard. The adoption of the revisions incorporated into 18 AAC 50.076 are sufficient to meet 2020 Amendment Plan requirements for this control measure.

As noted in the analysis of Measure 31, recent wood sales data show that 8-foot rounds account for 20.17% of wood sales in the Fairbanks nonattainment area. The sales estimates show approximately 1,511 cords of 8-foot logs were sold compared to a total of 7,491 cords sold and is a small fraction of the cordwood consumed in the non-attainment area which is 66,217 cords per year showing that 8-foot rounds account for approximately 2.28% of cordwood consumed in the non-attainment area. The low sales volume of 8-foot rounds combined with the requirement that it cannot be burned in the coming season ensures that the year-round dry wood sales mandate for Fairbanks after October 1, 2021, more than offsets the seasonal dry wood sales requirements mandated in Measure 31. They also ensure that seasonal labeling requirements offset the seasonal labeling requirements of Measure 32.

EPA in their comments[60] on the 2020 Amendments, cited similar issues as Measure 31 as lacking sufficient monitoring to be enforceable as a practical matter and thus meet BACM and BACT requirements. In response, ADEC is revising regulation 18 AAC 50.076(k)(1) by improving the labeling to clearly indicate "dry wood".

Conclusion

The adoption of the revised state regulation addresses the enforceability issues cited by EPA and therefore meets the BACM requirements for the 2024 Amendment.

Measure 35: Restrict Burning During Air Pollution Events

Implementing Jurisdiction(s)

- Klamath County; Ada County

Regulation Weblink(s)

- http://www.co.klamath.or.us/EH/Air%20Quality%20&%20Burning/Klamath%20County%20Clean%20Air%20Ordinance.htm
- http://www.sterlingcodifiers.com/codebook/index.php?book_id=447

[60] 88 Fed. Reg. at 1480. Technical Support Document: Docket No. EPA-R10-AOAR-2022-0115.

Background

Klamath County OR prohibits open burning during burning curtailment periods (Section 406.100.4.a). Oregon Department of Environmental Quality regulations exempt recreational fires and ceremonial fires from open burning requirements (Section 340-264-0040).

Ada County ID prohibits the open burning of refuse or solid fuel during declared air quality alerts (Section 5-10-8.C). County regulations also exempt recreational or warming fires from open burning restrictions provided that such fires do not violate air pollution alerts (Section 5-2-7-2.D).

Alaska Department of Environmental Conservation prohibits open burning in $PM_{2.5}$ nonattainment areas between November 1 and March 31 (Section 18 AAC 50.065.f). These regulations also exempt ceremonial fires from open burning restrictions (Section 18 AAC 50.990.65.B).

Analysis

The BACM analysis of this measure is unchanged - the measures adopted by Klamath County and Ada County contain the same exemptions from open burning restrictions for recreational fires as are contained in the Alaska regulations. Exempt fires are rarely ignited in Fairbanks when ambient temperatures reach subzero levels that are typical during Stage 1 Alert periods.[61] The removal of the ceremonial fire exemption will have no measurable emissions benefit in the Fairbanks nonattainment area.

40 CFR 51.1000 defines BACM as a control measure that "generally can achieve greater permanent and enforceable emission reductions … than can be achieved through implementation of RACM". Given that the measure does not result in a quantifiable emission benefit this control measure does not meet the definition of BACM.

With no quantifiable emission benefit and some associated cost to implement, the dollar per ton value would be infinite which shows economic infeasibility as well.

Conclusion

The BACM conclusion of these measures is unchanged - the measures as adopted by Klamath County and by Ada County do not meet the definition of BACM and 2020 Amendment Plan requirements and are economically infeasible. These measures have been dismissed from consideration as control measures for the 2020 Amendment to the Serious SIP.

Measure 38: Ambient $PM_{2.5}$ Curtailment Threshold (1-Hr Average)

Applicable Jurisdiction(s)

[61] Personal communication between Nicholas Czarnecki, FNSB Air Quality Division, and Bob Dulla, Trinity Consultants, on January 25, 2018.

- Cache Valley and Cities, Idaho

Regulation Weblink(s)

- https://adminrules.idaho.gov/rules/2014/58/0101.pdf

Background

Many jurisdictions with wood smoke control programs have adopted specific air quality thresholds for triggering burn bans, or curtailments, during which certain activities that produce $PM_{2.5}$ emissions are prohibited, or at least severely restricted. The Idaho Department of Environmental Quality (IDEQ) is the only regulatory agency found to trigger curtailment periods on the basis of ambient $PM_{2.5}$ levels measured over 1-hour averaging periods. Most other air quality agencies with burn ban authority base curtailment decisions on $PM_{2.5}$ levels averaged over 12- to 24-hour periods. Most importantly, this local 1-hour threshold in the Cache Valley and cities of Idaho applies only to curtailment or cessation of open burning, not wood-based residential space heating.

Under the Idaho Administrative Code, IDEQ has the authority to issue a Stage 1 Forecast and Caution when "particulate concentrations reach, or are forecasted to reach, and persist, at or above the levels listed" in the table below.[62] Under the Stage 1 Air Pollution Forecast and Caution, "there shall be no new ignition of open burning of any kind." In addition, the director of the IDEQ may request the cessation of open burning. (Again, this Stage 1 Forecast and Caution applies only to open burning and does not apply to residential wood heating.)

Table 8. Stage 1 Forecast Levels

Pollutant	Standard
$PM_{2.5}$	80 µg/m^3 1 hour average
$PM_{2.5}$	50 µg/m^3 24 hour average
PM_{10}	385 µg/m^3 1 hour average
PM_{10}	150 µg/m^3 24 hour average

This authority is also found in IDEQ's Air Pollution Emergency Rule.[63]

[62] Idaho Department of Environmental Quality, Idaho Administrative Code, Rules for the Control of Air Pollution in Idaho, IDAPA 58.01.01, available at https://adminrules.idaho.gov/rules/2014/58/0101.pdf; Accessed October/10/2017.
[63] https://www.deq.idaho.gov/media/344469-emerg_rule_fs.pdf; Accessed October 10, 2017.

Analysis

The BACM analysis of this measure is unchanged - discussions with staff members of IDEQ[64] and the Utah Department of Environmental Quality (UDEQ)[65] found the jurisdictions share a common $PM_{2.5}$ nonattainment area and thus coordinate regulations on many air quality issues; they indicated that the 1-hour standard is outdated and no longer used. Staff members from UDEQ indicated that they had no regulations based upon 1-hour standards and that all regulations were based upon 24-hour averaging periods. The $PM_{2.5}$ thresholds, for example, have never been updated to correlate to the current NAAQS standards. Staff from IDEQ instead use a 24-hour concentration of 30 $\mu g/m^3$ as a curtailment threshold and are considering a lowering of their 24-hour standard if that proposed by Utah is accepted and required by EPA.

Moreover, the Alaska Department of Environmental Conservation (ADEC) already has a state regulation in place[66] that prohibits open burning in the Fairbanks $PM_{2.5}$ nonattainment area between November 1 and March 31, the period that essentially corresponds to historical $PM_{2.5}$ violations.

The 1-hour concentration-based threshold adopted in Idaho applies to curtailment/cessation of open burning, not residential space heating. ADEC's existing regulation (18 AAC 50.065) prohibits open burning in the nonattainment area during the winter season. Thus, implementation of the Idaho 1-hour average threshold for curtailing open burning would have no impact on wood smoke emissions during the wintertime nonattainment season in Fairbanks, and is not applicable to curtailment or restrictions on residential space heating. In summary, ADEC's ban on open burning during the winter season is more stringent than this measure.

40 CFR 51.1000 defines BACM as a control measure that "generally can achieve greater permanent and enforceable emission reductions … than can be achieved through implementation of RACM." Given that the measure does not result in a quantifiable emission benefit this control measure does not meet the definition of BACM.

With no quantifiable emission benefit and some associated cost to implement, the dollar per ton value would be infinite which shows economic infeasibility as well.

Conclusion

The BACM conclusion is unchanged - the adoption of this measure will provide no emissions benefit in the Fairbanks nonattainment area, therefore the measure does not meet the definition of BACM and is economically infeasible. This measure has been dismissed from consideration as a control measure for the 2020 Amendment to the Serious SIP.

[64] Personal communication with Melissa Gibbs, Idaho Department of Environmental Quality, October 5, 2017.
[65] Personal communications with Bo Call, Utah Department of Environmental Quality, October 4, 2017; Personal communication with Joel Karmazyn, October 5, 2017.
[66] 18 AAC 50.065

Measure 39: Use of AQI as Basis for Curtailment Threshold

Applicable Jurisdiction(s)

- Cache Valley and Cities, Idaho

Regulation Weblink(s)

- http://www.deq.idaho.gov/media/930593-cache-valley-pm2-5-sip-appendices-1212.pdf

Background

Franklin County and the Cache Valley cities in Idaho use a $PM_{2.5}$ Air Quality Index (AQI) level of 75 as the threshold for declaring a burn ban (curtailment) for residential wood stoves. This level is equivalent to an ambient concentration of 23.5 $\mu g/m^3$.[67] Most other jurisdictions that regulate residential wood burning specify $PM_{2.5}$ concentration-based thresholds for a curtailment declaration (typically in the 25-35 $\mu g/m^3$ range) rather than specifying AQI levels. ADEC's concentration based thresholds for Stage 1 and Stage 2 are 20 and 30 $\mu g/m^3$.

The Cache Valley attainment plan submitted to the EPA by the Idaho Department of Environmental Quality states, in many locations, that burning is prohibited when the AQI for the region reaches 75 or higher.[68] The restriction applies, in one section, to "all wood burning, including but not limited to, within a solid fuel heating appliance designed for wood fuel (commonly known as a 'wood stove') or open fireplace" and in another to "any open burning of any kind."

Analysis

The BACM analysis of this measure is unchanged - personal communication with Idaho DEQ[69] staff suggested that the adoption of an AQI-based threshold rather than a $PM_{2.5}$ concentration-based threshold was motivated solely by the desire to avoid having to rewrite regulations to modify the "trigger level" when EPA revised the NAAQS. The AQI is itself a function of the NAAQS standard and so, when the standard is reduced by EPA, the concentration equivalent to an AQI of 75 – or any other measure of AQI – would correspondingly be reduced as well.[70] Thus the jurisdiction would not need to modify its regulation in response to a NAAQS change. The staff member indicated that no documentation existed to suggest whether the use of AQI- or concentration-based thresholds would be more effective at reducing emissions.

Further communication with the Idaho DEQ suggested that the use of an AQI- rather than a concentration-based threshold did not likely affect the compliance rate of affected woodstoves

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[67] https://airnow.gov/index.cfm?action=airnow.calculator

[68] Idaho Department of Environmental Quality, Cache Valley Idaho $PM_{2.5}$ Nonattainment Area SIP, Appendix E: Reasonably Available Control Methods, 2006, available at http://www.deq.idaho.gov/media/930593-cache-valley-pm2-5-sip-appendices-1212.pdf; Accessed October 10, 2017.

[69] Personal communication with Melissa Gibbs, Idaho Department of Environmental Quality, October 5, 2017.

[70] Calculator for AQI maintained by EPA at https://airnow.gov/index.cfm?action=airnow.calculator

and that the news release containing the curtailment order typically did not even mention the criteria used to initiate the curtailment.

40 CFR 51.1000 defines BACM as a control measure that "generally can achieve greater permanent and enforceable emission reductions … than can be achieved through implementation of RACM." Given that the measure does not result in a quantifiable emission benefit this control measure does not meet the definition of BACM.

With no quantifiable emission benefit and some associated cost to implement, the dollar per ton value would be infinite which shows economic infeasibility as well.

Conclusion

The BACM conclusion is unchanged - given the equivalence between AQI and $PM_{2.5}$ concentration thresholds the question of technological feasibility depends on the stringency of adopted AQI thresholds; therefore, this measure provides no emission benefit and does not meet the definition of BACM or a control measure for this 2020 Amendment and is economically infeasible. This measure has been dismissed from consideration as a control measure for the 2020 Amendment to the Serious SIP.

Measure 42: Burn Down Period

Implementing Jurisdiction(s)

- Puget Sound CAA; Maricopa County

Regulation Weblink(s)

- http://www.pscleanair.org/219/PSCAA-Regulations
  https://www.maricopa.gov/DocumentCenter/View/2016/P-26---Residential-Woodburning-Restriction-Ordinance-PDF

Background

The Puget Sound Clean Air Agency requires solid fuel burning devices to be shut down when a First Stage of Impaired Air Quality (curtailment) has been declared (Sections 13.05.a.1 and 13.05.d.1.a). Certain categories of devices, such as pellet stoves, Oregon DEQ-certified Phase 2 devices, Washington DOE-certified devices, and devices in households with no other adequate source of heat, are allowed to continue operating during a curtailment period provided that all applicable registration requirements are met. When a curtailment period is declared, fuel to non-exempt devices must be withheld, and combustion in these devices – as evidenced by visible smoke from a chimney – must cease within three hours after the declaration is issued (Section 13.05.b).

Maricopa County defines "Burn-Down Period" as "That period of time, not to exceed three hours after declaring a restricted-burn period, required for the cessation of combustion within any residential wood-burning device, outdoor fire pit, wood-burning chimney, or similar outdoor fire by withholding fuel or by modifying the air-to-fuel-ratio" (Section P-26.2.D). This regulation also stays enforcement of visible emission limits for three hours after a curtailment declaration is issued (Section P-26.3.D.4).

Fairbanks' regulations did not specifically exempt smoke emitted during burn down periods from compliance with opacity limits, but do exempt visible emissions from a chimney in excess of the opacity standard for a period not to exceed 30 minutes during a curtailment period before citing unauthorized wood heating devices for unlawful operation during a curtailment period. Those Borough regulations were removed following the passage of the Home Heating Reclamation Act.

Analysis

In the Serious SIP, effective January 8, 2020, Alaska added a regulation subsection 18 AAC 70.075(e)(3) "that fuel to non-exempt devices must be withheld, and combustion in these devices – as evidenced by visible smoke from a chimney – must cease within three hours of the effective time of the declaration."

The addition of this subsection matches the burn down requirements set in Measure 42. Therefore, the adoption of this measure addressed the BACM requirement for this measure.

The Serious SIP is a chapter of the State Air Quality Control Plan that is adopted by reference into state regulation at 18 AAC 50.030. As a result, the Fairbanks Emergency Episode Plan as described in Section III.D.7.12 is enforceable by ADEC. This section of the SIP outlines for the public the specifics related to episodic control requirements within the nonattainment area along with the process ADEC uses for announcing episodes. ADEC revised Section III.D.7.12 to incorporate the language added to 18 AAC 50.075(e) to ensure that the burn down requirements are clearly identified within the local Episode Plan.

ADEC also uses a fixed episode announcement template that will have the burn down language included so that every curtailment called within the nonattainment area will contain the burn down language.

Conclusion

The adoption of the referenced state regulations are sufficient to meet the 2020 Amendment Plan requirements of this measure, therefore the measure is technologically feasible, adopted and implemented, and no additional analysis is required.

Measure 45: Elevation Exemption from Wood Burning Curtailments

Implementing Jurisdiction(s)

- South Coast Air Quality Management District; Utah Department of Environmental Quality

Regulation Weblink(s)

- http://www.aqmd.gov/docs/default-source/rule-book/rule-iv/rule-444.pdf
- https://rules.utah.gov/publicat/code/r307/r307-302.htm#T3

Background

In the South Coast, Mandatory Winter Burning Curtailment is defined to occur:

> *..during the consecutive months of November through February where the burning of solid fuels is restricted for portions of the South Coast Air Basin at elevations below 3,000 feet above Mean Sea Level (MSL) based on air quality criteria contained in AQMD Rule 445 (Wood Burning Devices).* (emphasis added)

Utah's Rule 307 (Solid Fuel Burning) provides exemption from wood burning restrictions for sources located at elevations above 7,000 feet.

Alaska DEC does not provide an elevation exemption from burning curtailment requirements.

Analysis

The BACM analysis of this control measure is unchanged - a review of topographical maps found that no portion of the Fairbanks $PM_{2.5}$ nonattainment area is at an elevation above 3,000 feet MSL. This finding was confirmed by the Borough's Air Quality Division. The existing Alaska DEC air quality regulations do not provide an elevation exemption from burning curtailment requirements.

40 CFR 51.1000 defines BACM as a control measure that "generally can achieve greater permanent and enforceable emission reductions … than can be achieved through implementation of RACM". Given that the measure does not result in a quantifiable emission benefit this control measure does not meet the definition of BACM.

With no quantifiable emission benefit and some associated cost to implement, the dollar per ton value would be infinite which shows economic infeasibility as well.

Conclusion

The BACM conclusion is unchanged - this measure would not result in a quantifiable emission benefit and thus does not meet the definition of BACM and control measure requirements for the 2020 Amendment and is economically infeasible. This measure has been dismissed from consideration as a control measure for the 2020 Amendment to the Serious SIP.

Measure 46: Lack of Electrical or Natural Gas Service Availability

Implementing Jurisdiction(s)

- South Coast Air Quality Management District; San Joaquin Valley Air Pollution Control District

Regulation Weblink(s)

- http://www.aqmd.gov/docs/default-source/rule-book/rule-iv/rule-445.pdf?sfvrsn=4
- https://www.valleyair.org/rules/currntrules/r4901.pdf

Background

The South Coast Air Quality Management District exempts wood heating devices from burning curtailment requirements in households where there is no existing infrastructure for natural gas service within 150 feet of the property line (Section 445.f.7.C).

San Joaquin Valley Air Pollution Control District exempts wood burning fireplaces and wood burning heaters from burning curtailment requirements in areas where natural gas service is not available (Section 4901.5.6.3.1).

Fairbanks did not exempt households from curtailment requirements due to a lack of natural gas service, but it did allow all wood heating devices affected by an electrical power failure to be used for space heating purposes during Stage 1 alerts. Fairbanks curtailment requirements were removed with the passage of the Home Heating Reclamation Act.

Analysis

The BACM analysis of this control measure is unchanged - the Episode Chapter of the $PM_{2.5}$ Serious SIP, provides an exception for cases where electrical power outages prevent use of alternative heating devices. This requirement is not overly broad as electricity is required to power all alternative (i.e., non-wood) heating devices, since they require pumps, fans, resistance coils, valves, etc. for operation. Thus, with the exception of wood-fired heating there is no alternative source of heat when there is an electrical power outage, unless the home has a generator.

40 CFR 51.1000 defines BACM as a control measure that "generally can achieve greater permanent and enforceable emission reductions … than can be achieved through implementation of RACM." Given that the measure does not result in a quantifiable emission benefit this control measure does not meet the definition of BACM.

With no quantifiable emission benefit and some associated cost to implement, the dollar per ton value would be infinite which shows economic infeasibility as well.

Conclusion

The BACM conclusion for this measure is unchanged - since the adoption of this measure will provide no emission reductions in Fairbanks, it does not meet the definition of BACM or the control measure requirements for the 2020 Amendment and is economically infeasible. This measure has been dismissed from consideration as a control measure to the 2020 Amendment to the Serious SIP.

Measure 48: Date Certain Removal of "Coal Only Heater"

Implementing Jurisdiction(s)

- **Puget Sound Clean Air Agency**

Regulation Weblink(s)

- **https://www.pscleanair.org/DocumentCenter/View/354**

Background

Puget Sound CAA Regulation 13.07 mandates the removal of coal-only heaters located in Tacoma:

> ***Any person who owns or is responsible for a coal-only heater located in the Tacoma, Washington fine particulate nonattainment area must remove and dispose of it or render it permanently inoperable by September 30, 2015.***

It also requires that owners provide documentation of the removal and disposal or rendering permanently inoperable of the coal heater to the Agency using the Agency's procedures within 30 days of the removal or rendering the heater permanently inoperable.

Fairbanks restricted the operation and installation of coal burning devices. Coal burning stoves, hydronic heaters and furnaces are defined as solid fuel burning appliances (SFBA). None of these appliances are Borough "listed appliances". All listed appliances must be EPA-certified and have an annual average emission rating of 2.5 grams per hour or less or 0.10 lbs/mm Btu for hydronic heaters. This effectively prohibited the installation of other types of solid fuel-fired heating devices, including coal, unless the Borough approves an independent emission test showing the device meets the emission standards. Fairbanks requirements addressing the installation and operation of coal burning devices were removed with the passage of the Home Heating Reclamation Act.

The State of Alaska adopted regulations and SIP amendments which became effective January 12, 2018 that prevented unlisted appliances (i.e., coal heaters) from being installed, sold or leased for use within the Fairbanks $PM_{2.5}$ nonattainment area. They cannot be operated during Air Quality Alerts, do not qualify for NOASH certificates, but do qualify for the enhanced voluntary, removal, replacement and repair program.

In the 2020 Amendments, Alaska added a new subsection to 18 AAC 50.079(f) which requires coal-fired heating devices to be removed or replaced by the earlier of December 31, 2024, or before the device is sold, leased, or conveyed as part of an existing building. The removed devices must be destroyed or rendered inoperable and cannot be advertised for sale within the nonattainment area. EPA in their comments on 2020 Amendment, disapproved sections of 18 AAC 50.079 and stated that 18 AAC 50.079 (f) does not specify a process to confirm the device was rendered inoperable, 18 AAC 50.079 (d) allows the owners to test out of the mandatory removal requirements, and 18 AAC 50.079 (e) includes an unbounded waiver provision.

In response, ADEC is revising 18 AAC 50.079 by lowering the emission threshold to test out of the mandatory removal requirements in 18 AAC 50.079(d) from 18 grams per hour to 0.10 pounds per million Btu which is equivalent to the pellet hydronic heater limit in 18 AAC 50.077. 18 AAC 50.079(d) was amended to require a testing protocol be approved by the department prior to any test attempting to exempt a coal device from the mandatory removal requirement. 18 AAC 50.079(e) was revised to add a time limit of one calendar year to bound the waiver. 18 AAC 50.079(f) was revised for clarity and by adding section (3) which requires coal-fired heating devices to be rendered inoperable after expiration of a waiver granted under subsection (e) of 18 AAC 50.079. A new section 18 AAC 50.079(h) was added that requires documentation on the removal and rendering of the device inoperable and submitting an affidavit that coal stove will not be reinstalled in the Nonattainment Area.

Analysis

As discussed in the Introduction, Alaska added a new subsection to 18 AAC 50.079(f) which requires coal-fired heating devices to be removed or replaced by December 31, 2024. They must be removed or replaced prior to any conveyance of an existing building and cannot be sold, leased or distributed for sale. The removed devices must be destroyed or rendered inoperable and cannot be advertised for sale within the nonattainment area.

In the 2020 Amendment, ADEC stated that the removal and destruction requirements were consistent with the Measure 48 regulations mandating the date certain removal of coal only heaters. With regard to the documentation requirements, since no new coal burning units will be sold, 18 AAC 50.079 (f) permanent inoperability requirements will apply.

EPA in their comments on the 2020 Amendment, dismissed the measure by stating that Alaska's regulation was not as stringent as Puget Sound regulation. EPA commented that while the Alaska regulations ban the new installation of coal-fired devices and require existing stoves be rendered inoperable as part of a real estate transaction or by December 31, 2024, the regulations under 18 AAC 50.079 do not stipulate a process to confirm the device was rendered inoperable (as is required in the Puget Sound regulations). Further, the temporary waiver in 18 AAC 50.079(e) does not specify the length of time a waiver will be provided, and thereby does not provide an accurate estimate of the number of coal-fired devices that will be rendered inoperable by the end of 2024. Alaska's regulations under 18 AAC 50.079(d) also allowed these devices to remain in use if a maximum emission rate test does

not exceed 18 grams per hour of total particulate matter. There is no similar testing exemption under the Puget Sound Clean Air Agency's rules.

As discussed under Background ADEC updated sections (d), (e), (f), and (h) of 18 AAC 50.079 to resolve EPA's identified deficiencies. Regarding EPA's comment that no testing provision exists under the Puget Sound Clean Air Agency Rules, pellet and coal hydronic heaters are both part of a larger subset of solid fuel hydronic heaters, and it is appropriate to adopt an equivalent emission standard indifferent of the fuel and control strategies. An equivalent emission standard is appropriate because "best" is in terms of BACM refers to the overall level of emission reductions[71] and an equivalent emission standard will result in the greatest level of emission reduction by ensuring that the cleanest heating options remain available in the Fairbanks nonattainment area. ADEC is revising 18 AAC 50.079 by adding a new section (h) that requires documentation on the removal and rendering the device inoperable and submitting an affidavit that coal stove will not be reinstalled in the Nonattainment Area.

Conclusion

The adoption of the referenced state regulations is sufficient to meet the BACM requirements of this measure, therefore the measure is technologically feasible, and no additional analysis is required.

Measure 49: Prohibit Use of Coal Burning Heaters

Implementing Jurisdiction(s)

- **Town of Telluride and San Miguel County, Colorado**

Regulation Weblink(s)

- **https://yosemite.epa.gov/R8/R8Sips.nsf/PrintSips/C5D17E5CB9461F8587257EED004BBD82?OpenDocument**

Background

The town of Telluride and San Miguel County adopted wood and coal burning emission reduction measures in the 1980's and 1990's, including provisions that:

(1) ***Require the installation of cleaner burning devices in existing dwellings which have pre-existing solid fuel burning devices;***
(2) ***prohibit solid fuel burning devices in new construction;***
(3) ***ban coal burning; and***
(4) ***limit the total number of fireplaces and woodstoves in the nonattainment area.***

These controls were approved by EPA into the Colorado PM_{10} SIP in 1994.[72]

Fairbanks air quality regulations defined coal stoves and coal burning hydronic heaters as Solid Fuel Burning Devices (SFBD). Coal burning stoves and hydronic heaters were not included as Borough-Listed Devices. Unlisted SFBDs could not be installed, did qualify for the Voluntary Replacement and Removal Program, and could not be operated during either a Stage 1 or Stage 2 Alert. Unlisted devices could receive a NOASH certification. Those regulations were Fairbanks requirements addressing the installation and operation of coal burning devices were removed with the passage of the Home Heating Reclamation Act.

Neither the Borough nor the State had regulations that banned coal burning.

EPA commented that they believed "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 $PM_{2.5}$."

In the 2020 Amendments, Alaska added a new subsection to 18 AAC 50.079(f) which requires coal-fired heating devices to be removed or replaced by the earlier of December 31, 2024, or before the device is sold, leased, or conveyed as part of an existing building. The removed devices must be destroyed or rendered inoperable and cannot be advertised for sale within the nonattainment area. Coal-fired devices are eligible for changeouts under the Targeted Airshed Grant and the date of 2024 provides residents adequate time to participate in the solid fuel burning appliance change-out program to comply with the regulation without overwhelming the Borough program resources.

In response to 2020 Amendment, EPA had similar concerns with this measure as Measure 48 and commented that the waiver in 18 AAC 50.079(e) does not specify the length of time a temporary waiver would apply.

In response, ADEC is revising 18 AAC 50.079 by lowering the emission threshold to test out of the mandatory removal requirements in 18 AAC 50.079(d) from 18 grams per hour to 0.10 pounds per million Btu which is equivalent to the pellet hydronic heater limit in 18 AAC 50.077. 18 AAC 50.079(d) was amended to require a testing protocol be approved by the department prior to any test attempting to exempt a coal device from the mandatory removal requirement. 18 AAC 50.079(e) was revised to add a time limit of one calendar year to bound the waiver. 18 AAC 50.079(f) was revised for clarity and by adding section (3) which requires coal-fired heating devices to be rendered inoperable after expiration of a waiver granted under subsection (e) of 18 AAC 50.079. A new section 18 AAC 50.079(h) was added that requires documentation on the removal and rendering of the device inoperable and submitting an affidavit that coal stove will not be reinstalled in the Nonattainment Area.

Analysis

In the Serious SIP and 2020 Amendment, Alaska adopted requirements for wood-fired heating devices at 18 AAC 50.075, 076, and 077. Coal fired heating devices are addressed in 18 AAC 50.079. As described above a new subsection to 18 AAC 50.079(f) requires coal-fired heating devices to be rendered permanently inoperable by December 31, 2024, or before the device is sold, leased, or conveyed as part of an existing building. These restrictions are not limited to curtailment Alerts and therefore directly address EPA's concern about contributing additional emissions to the airshed.

EPA in their comments on the 2020 Amendment dismissed the measure and stated that the waiver in 18 AAC 50.079(e) is unbounded and does not specify the length of time a temporary waiver would apply, and this impacted the evaluation of the effectiveness of the coal-fired device restrictions. EPA also noted that a restriction on installing wood-fired devices in new construction is not currently feasible in the Fairbanks area. As discussed under Background ADEC updated sections (d), (e), (f), and (h) of 18 AAC 50.079 to resolve EPA's identified deficiencies. The unbounded waiver condition in 18 AAC 50.079(e) has been bounded with a time limit of one calendar year, and language requiring the documentation of removal of coal devices has been added to 18 AAC 50.079(f) which will provide for emission reductions outside of the curtailment program.

Conclusion

The adoption of the referenced state regulations is sufficient to meet the BACM requirements of this measure, therefore the measure is technologically feasible and no additional analysis is required.

Measure 50: Require Low Sulfur Content Coal

Implementing Jurisdiction(s)

- Puget Sound Clean Air Agency, State of Utah

Regulation Weblink(s)

- https://pscleanair.gov/DocumentCenter/View/354/Regulation-I?bidId=

Background

Section 13.04 of the Puget Sound CAA regulations restricts the sulfur content of coal burned in a solid fuel burning device. It allows only the burning of:

> *Coal with sulfur content less than 1.0% by weight burned in a coal only heater.*

Utah regulates the sulfur and ash content of coal for residential use, with the following restrictions:

(1) After July 1, 1987, no person shall sell, distribute, use or make available for use any coal or coal containing fuel for direct space heating in residential solid fuel burning devices and fireplaces which exceeds the following limitations as measured by the American Society for Testing Materials Methods:

(a) 1.0-pound sulfur per million BTU's, and
(b) 12% volatile ash content.

(2) Any person selling coal or coal containing fuel used for direct residential space heating within the State of Utah shall provide written documentation to the coal consumer of the sulfur and volatile ash content of the coal being purchased.

Alaska DEC does not regulate the sulfur content of coal burned in solid fuel burning appliances.

Analysis

The BACM analysis of this control measure is unchanged - the Usibelli Coal Mine is the source of all coal marketed and burned in Fairbanks. Their factsheet[73] indicates the sulfur content of coal from the Healy mine is typically 0.2% with a range of 0.08% - 0.28%. The Healy mine supplies the coal burned in Fairbanks.

Fairbanks has no restriction on the sulfur content of coal marketed and burned within the $PM_{2.5}$ nonattainment area; therefore, the Puget Sound regulation is more restrictive. The sulfur content of Healy coal, however, is well below the 1% threshold mandated by Puget Sound. Therefore, while the Puget Sound regulation is more restrictive, its imposition in Fairbanks will have no effect on coal burning and no emissions benefit.

The Healy fact sheet indicates that the heat content of their coal is 7,560 BTU/lb. Using this value, 132.3 lbs. of coals is needed to produce 1 million BTU. This value combined with the 0.2% content of coal produces 0.26 lbs. of sulfur, which is well below Utah sulfur threshold 1.0 lb. per million BTU. The Healy coal has a 7% average ash content ranging from 4% - 12%, which falls below the 12% volatile ash content Utah threshold.

Alaska adopted 18 AAC 50.079 with the Serious Area SIP. 18 AAC 50.079 (f) requires the owner of an existing coal-fired heating device to render the device inoperable by the earlier of December 31, 2024; or before the device is sold, leased, or conveyed as part of an existing building. The Emergency Episode Plan adopted with the Serious Area SIP does not provide for a NOASH provision for residential coal-fired heating devices. Current regulations will continue to force turnover of coal-fired heating devices and replacement with non-coal alternatives.

[73] http://www.usibelli.com/coal/data-sheet

Conclusion

The BACM conclusion is unchanged - the Puget Sound and Utah coal content regulations, if adopted by Alaska DEC, would not reduce $PM_{2.5}$ emissions in Fairbanks as the sole source of coal used in the Borough continuously satisfies the Puget Sound and Utah specifications, and current regulations require the removal of all residential coal-fired heating devices; therefore, this measure is not technologically feasible and not eligible for consideration as a control measure for the 2020 Amendment to the Serious SIP.

Measure 51: Ultra-low Sulfur Heating Oils Implementing Jurisdiction(s)

Implementing Jurisdiction(s)

- **Northeast States and Alaska**

Regulation Weblink(s)

- **https://noraweb.org/wp-content/uploads/2014/11/NEMARegion_ULSDBioChart2014.pdfhttps://www.epa.gov/diesel-fuel-standards/diesel-fuel-standards-and-rulemaking**

Background

As part of the BACM analysis included in the Fairbanks Serious Plan, Alaska evaluated requirements to use ULSD heating oil in homes. It identified 10 states plus large municipal areas that have instituted ULSD home heating requirements and determined the measure to be technologically feasible. The economic analysis showed this change would result in a cost of $1,819 per ton of SO_2 removed. While the measure was determined to be both technologically and economically feasible, Alaska declined to adopt and implement the measure. Instead, the state elected to mandate a fuel switch from Diesel #2 (approximately 2000 ppm) to Diesel #1 (1,000 ppm) through the adoption of regulation 18 AAC 50.078(b)[74] for residential and commercial heating, which became effective on September 1, 2022.

In support of the decision, ADEC provided several community-based considerations if Fairbanks Nonattainment Area were to undergo the switch from Diesel #2 to ULSD. These considerations included potential environmental impacts caused by greater transportation requirements required to maintain an adequate ULSD supply through the winter in Fairbanks. ADEC also cited a University of Alaska Fairbanks/Alaska cost analysis.[75] That analysis estimated an increase in annual household heating expenditures of $68.31 (a 3 percent increase) under the selected measure of converting from #2 to #1, while the same

[74] https://dec.alaska.gov/media/1038/18-aac-50.pdf

[75] Residential Fuel Expenditure Assessment of a Transition to Ultra-Low Sulfur and High Sulfur No. 1 Heating Oil for the Fairbanks PM-2.5 Serious Nonattainment Area, February 2019, Prepared by The Alaska Department of Environmental Conservation Economist in collaboration with the University of Alaska Fairbanks Master of Science Program in Resource and Applied Economics.

cost analysis estimated an increase between $311.96 and $374.86 (a 13.5 to 16.5 percent increase) in annual household heating expenditures if Alaska mandated a switch to ULSD. ADEC also cited concerns from local residents that the increased cost of fuel oil could drive more residents to burn less expensive and higher PM emitting solid fuels. Based on the analysis, ADEC noted that the price elasticity of demand is highly elastic and that any increase in fuel price will lead to greater demand for wood leading to higher emissions. Alaska reevaluated the economic feasibility of the switch from #2 to USLD as part of the Fairbanks 189(d) Plan submission, although there were not any changes to warrant revisiting its decision to reject adoption of ULSD since the Serious Plan submission.

The updates made to the economic analysis were based on the comments received from EPA and refiners. ADEC found the cost of adopting this measure to be $1,810 per ton of SO_2 reduced (based on fuel prices in 2018 plus a price premium of $0.41 per gallon for ULSD), which is cost-effective. ADEC stated that while the increase in cost, however, is slight and EPA has indicated that higher cost measures must be accepted in the 2020 Amendment relative to the controls adopted in the Serious SIP. For this reason, the shift from No. 2 to ULS is cost-effective and should be considered for adoption. Despite being technologically and economically feasible, ADEC continued to reject the adoption of ULSD based on local considerations wherein ULSD cannot be produced at a local refinery, and to meet to needs for the use of ULSD in the Nonattainment area would result in all of the fuel to be imported from Anchorage by either rail or truck, both are which increases cost, difficulties due to inclement weather conditions, and environmental risks of transport spills. Additionally, ADEC evaluated the effectiveness of requiring ULSD on modeled attainment. An alternative to the 2023 Control inventory described in the plan was developed in which all distillate fuel for GVEA North Pole as well as all other point sources and all residential and commercial space heating was assumed to be ULSD (15 ppmw sulfur). That "2023 ULSD" modeling analysis determined that attainment could still not be further advanced sooner than 2024 assuming a full transition to ULSD through the point and space heating sectors in 2023. The modeled design value for the 2023 run was 37.0 µg/m^3. The modeled design value for the 2023 USLD scenario was 36.9 µg/m^3, reflecting only a 0.1 µg/m^3 reduction from a transition to ULSD.

In their comments on the 2020 Amendment,[76] EPA rejected ADEC's dismissal of requiring ULSD for residential and commercial heating oil, because it believed ADEC did not establish that the measure is either technologically or economically infeasible. Alaska responded in March 2023 with comments that provided facts to demonstrate technological infeasibility and updated its cost-effectiveness analysis based on eight factors to demonstrate economic infeasibility.

The comment noted that since submitting Serious SIP and 2020 Amendment, the greater Fairbanks community has experienced several changes salient to the feasibility and cost-effectiveness of ULSD. Fuel prices have increased, the community converted from #2 to #1 heating fuel, and ADEC learned more about people's actual home heating behaviors

[76] 88 Fed. Reg. at 1481; Technical Support Document: Docket No. EPA-R10-AOAR-2022-0115.

through a survey. Each of these key changes in the community (or additional information gained) is summarized below.

- ***Market Prices of Heating Oil Have Risen Significantly*** **– In the original ULSD BACM analysis for the Serious SIP and 2020 Amendments, the retail price of heating oil in 2021 (the calendar year of the analysis) was assumed to be $2.86/gallon (projected from an actual 2019 price of $2.90/gallon). As of the end of 2022, heating oil prices had risen to $4.75/gallon and peaked over $5/gallon in summer 2022. This was not a one-time event. As explained later in the Methodology section, Fairbanks has a long history of large heating oil price swings. The implications of these significant oil price increases on the cost-effectiveness of USLD were examined in this response.**

- ***ADEC Performed a Local Survey of Oil Device Maintenance Practices*** **– The original ULSD cost-effectiveness analysis relied on oil device maintenance and cleaning information compiled from communities in the Northeastern U.S. from a 2015 Brookhaven National Laboratory study conducted in that region. To determine if maintenance intervals and costs in that study were representative of Fairbanks, ADEC conducted a survey in October 2022 of companies within the $PM_{2.5}$ nonattainment area that provide residential and commercial oil heater maintenance services. In short, it was found that the oil device maintenance interval in Fairbanks was close to that in the Northeast (at just over one year on average), but the cost per maintenance was nearly five times higher ($492 vs. $100). The impacts of this new local survey data were incorporated into the revised cost-effectiveness analysis.**

- ***Fairbanks Has Shifted to #1 Heating Oil*** **– Finally, since the community shifted to use of lower sulfur #1 heating oil in September 2022 due to adoption and implementation of 18 AAC 50.078(b), ULSD cost-effectiveness was also examined with #1 heating oil as the (now current) baseline heating fuel.**

These and other revisions were incorporated with eight distinct revisions, to the cost-effectiveness analysis that ADEC submitted for ULSD with the 2020 Amendments to the Serious SIP.

A cross-price elasticity analysis for the Fairbanks Nonattainment Area found that mandating a switch to ULSD heating oil would increase direct $PM_{2.5}$ emissions in the Nonattainment Area. When oil prices rise, residents switch to wood heating because it is less expensive. This documented economic relationship would render this measure ineffective for attempting to improve air quality in Fairbanks.

Testimony at the EPA hearing in Fairbanks on March 7, 2023, bore out this truth, with multiple residents testifying that they desperately want cleaner air to breathe but would switch to wood heating if oil prices rose because they simply could not afford the cost during bitter winters. People do not want to die from polluted air, and they also do not want to die of cold. Unlike less extreme and isolated environments, in Fairbanks there is little cheap fuel available other than wood heating, heating costs are must higher than in less extreme climates, and heating oil prices are volatile. The cost of utilities in Fairbanks

is already 110% higher than the national average[77] but ULSD would raise prices even higher. ADEC's curtailment program and the Fairbanks North Star Borough's woodstove change out program could not effectively mitigate the harmful air quality effects of this policy, particularly when woodstoves installed prior to the effective dates of ADEC's device restrictions[78] likely emit more than they are certified or modelled to emit.[79]

Analysis

An abbreviated listing of the key facts included in Alaska's comments on EPA's proposed disapproval of the ADEC's ULSD control measure analysis[80] is presented below. Those comments are followed by the EPA's Response to public comments received on that proposal and decisions included in the final rule.[81]

Technological Feasibility – ADEC and Other Comments

1. ***ULSD could not be produced locally because of the impossible economy of scale*** **- The greater Fairbanks area has one refinery, which is located in North Pole and owned by Petro Star ("North Pole refinery"). For heating oil, it switched from making #2 to #1 fuel oil in September 2022, in response to the requirement and timeline in 18 AAC 50.078(b). The North Pole refinery has none of the infrastructure necessary to make ULSD.[82] To make ULSD, the refinery would need to build a new ULSD plant and connect it to the existing plant.[83] For the Fairbanks market, the size of that ULSD plant would be so small as to create a negative economy of scale.[84] Realistically, ULSD cannot be produced locally.**

2. ***Fuel transportation networks to Fairbanks could not logistically support a switch to ULSD heating oil*** **- In Alaska, ULSD is produced at two refineries: Petro Star produces it in Valdez, and Marathon produces it in Nikiski.[85] To get ULSD to Fairbanks it would first be transported to Anchorage, via barge for Petro Star and pipeline for Marathon,**

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77 PayScale, Cost of Living in Fairbanks, Alaska, available at https://www.payscale.com/cost-of-living-calculator/Alaska-Fairbanks.
78 *See* ADEC, Solid Fuel-Fired Heating Device Standards & Requirements, available at https://dec.alaska.gov/air/burnwise/standards/.
79 Gilbride, et al., The EPA's Residential Wood Heater Program Does Not Provide Reasonable Assurance that Heaters Are Properly Tested and Certified Before Reaching Consumers Report No. 23-E-0012, (Feb. 28, 2023), available at https://www.epa.gov/office-inspector-general/report-epas-residential-wood-heater-program-does-not-provide-reasonable.
80 Response to Comments Regarding Best Available Control Measure Requirements for Residential and Commercial Fuel Oil Combustion on the Partial Approval and Partial Disapproval; AK, Fairbanks North Star Borough; 2006 24-hour PM2.5 Serious Area and189(d) Plan. Docket No.: EPA-R10-OAR-2022-0115, November 2, 2023
81 Air Plan Partial Approval and Partial Disapproval; AK, Fairbanks North Star Borough; 2006 24-hour PM2.5 Serious Area and189(d) Plan.
82 Personal communication with Ryan Muspratt, VP, Petro Star by Jennifer Seely, Alaska Department of Law on behalf of ADEC (March 16, 2023).
83 *Id.*
84 *Id.*
85 *Id.*

and then from Anchorage the fuel is transported by rail.[86] For Petro Star, the backup logistics would be to truck ULSD from Valdez to Fairbanks.[87] If ULSD was mandated for heating oil in the Fairbanks Nonattainment Area, Petro Star estimates that it would have to add 30-40 million gallons per winter of logistical capacity to transport heating oil to Fairbanks.[88]

The existing logistical network for trucking and rail transport is operating at near capacity. Other fuel products for non-heating uses must also be shipped to Fairbanks, like gasoline and jet fuel. The Alaska Railroad, which runs 470 miles from Seward to Fairbanks (through Anchorage), is the primary and most economical mode of transportation for fuel going to Fairbanks.[89] It likely cannot scale up its operations within the timescale required by the federal rule.[90] Trucking, which comes at an increased cost from rail transport, is also at capacity in Alaska.[91] New truckers are not meeting the demand created by retiring truckers, and incomes from trucking in the continental United States have increased, reducing the incentive for truckers to weather the dark and icy conditions in Alaskan winters.[92]

In Alaska, the fuel demand for heating, electricity, and transportation all peak in the winter.[93] It is cold and dark, and residents need more light and heat for more hours every day. Existing transportation capacity is insufficient to absorb the additional peaks in winter demand that would be caused by mandating ULSD.[94]

3. ***The greater Fairbanks area has materially different fuel transportation conditions than rural Alaska, which uses a different ultra-low sulfur fuel* - Unlike Fairbanks, rural Alaskan communities that are not on the road or rail system use an ultra-low sulfur fuel.[95] This fuel is not the same as ULSD.[96] Rather, it is a hybrid product that can also be used for jet fuel ("ULS/jet"), and is produced by an Asia refinery with a different method from that used to produce ULSD.[97] Rural Alaskan communities need this multi-use fuel because of their limited fuel storage capacity. With ULS/jet, rural communities can use one storage tank and one fuel for both transportation and heat.**

[86] *Id.*; *see also* McDowell Group, Statewide and Port of Alaska Long Range Fuel Forecast (November 20, 2020), available at https://www.portofalaska.com/wp-content/uploads/Alaska-PoA_Fuel_Forecast_Nov2020.pdf.
[87] *Id.*; *see also* FMATS Freight Mobility Plan (January 2019), available at https://fastplanning.us/wp-content/uploads/2019/07/freight-mobility-plan-for-approval.pdf.
[88] Personal communication with Ryan Muspratt, VP, Petro Star by Jennifer Seely, Alaska Department of Law on behalf of ADEC (March 16, 2023).
[89] *Id.*; *see also* FMATS Freight Mobility Plan (January 2019).
[90] 40 C.F.R. § 51.1010.
[91] Personal communication with Ryan Muspratt, VP, Petro Star by Jennifer Seely, Alaska Department of Law on behalf of ADEC (March 16, 2023).
[92] *Id.*
[93] *Id.*
[94] *Id.*
[95] 40 C.F.R. Part 80; 71 Fed. Reg. at 32450.
[96] Personal communication with Ryan Muspratt, VP, Petro Star by Jennifer Seely, Alaska Department of Law on behalf of ADEC (March 16, 2023).
[97] *Id.*

The circumstances and reasoning for this type of ULS/jet product are different from the circumstances surrounding the heating oil needs in the Fairbanks North Star Borough. It has a much higher population[98] **than rural Alaska communities and requires separate storage tanks for ULSD and other higher sulfur distillate oil. The logistics and costs associated with ULS/jet, and its transport from Asia through Bristol Bay to rural Alaska, are distinct from the logistics and costs that would be associated with transporting ULSD from different refineries, through different transportation methods, to the Fairbanks North Star Borough that needs more than one tank to survive the winter.**

For the foregoing reasons, ADEC determined that ULSD is not technologically feasible as BACM for the Fairbanks Nonattainment Area. It could not be produced locally, and the logistical transportation networks that would have to supply it to the greater Fairbanks area do not have that capacity.

Other commenters noted that ULSD has a lower energy value than higher sulfur fuel oil and that it is corrosive. Petro Star and other commenters expressed concerns that Alaska's warning that conversion to ULSD and consequent price increases could drive residents to burn more solid fuel.

Economic Feasibility – ADEC Comments
Revisions to the CE analysis from the 2020 Amendments submittal are summarized as follows:

1. ***Correction of Episodic to Annual Energy Use* – Factors used to adjust episodic to annual heating energy use were improperly applied in the 2020 Amendments analysis.**

2. ***Correction of Adjusted Energy Use Error* – A formula used to account for differences in wood vs. oil heating devices in calculating "With ULSD" energy use relative to a "Without ULSD" baseline was corrected.**

3. ***Consideration of Combined SO_2 and $PM_{2.5}$ Cost Effectiveness* – Although the ULSD CE analysis for the 2020 Amendments looked at emission changes and costs for both SO_2 and directly emitted $PM_{2.5}$, only the SO_2 cost effectiveness was discussed in the BACM analysis. Consideration of the emissions changes for both pollutants is important because of the cross-price elasticity relationships between oil prices and wood use contained in the SIP inventories based on locally collected survey data. When heating oil prices rise, Fairbanks residents shift to lower cost fuels (i.e., wood) to conserve heating expenses. The shift to wood produces higher $PM_{2.5}$ emissions, which must be accounted for in a CE analysis. Based on CE analysis methods supporting control strategy development in other nonattainment areas, the revised CE analysis includes calculations of emission reductions for both pollutants and a combined CE that accounts for the relative impact of emissions of both pollutants on ambient $PM_{2.5}$ formation in Fairbanks.**

[98] Approximately 95,593, as of 2021. U.S. Census Bureau, QuickFacts: Fairbanks city, Alaska; Fairbanks North Star Borough, Alaska, available at https://www.census.gov/quickfacts/fact/table/fairbankscityalaska,fairbanksnorthstarboroughalaska/PST045221.

4. ***Correction of Fuel Use Impacts from Reduced Boiler Fouling* – Based on a 2015 report[99] prepared by Brookhaven National Laboratory ("BNL") the 2020 Amendments analysis estimated that fuel use with #2 oil (2,000 ppm sulfur) would be 12% higher that with ULSD (15 ppm sulfur) due to fouling of heating elements caused by higher sulfur fuel. A more careful read of the report and contact with its lead author found that this 12% value was for a single household in a sample of 100 instrumented households that represented the largest effect of fuel use impacts of high sulfur fouling. The average fouling-related fuel use increase across all instrumented households was 1.5%.**

5. ***Incorporation of Local Oil Appliance Survey Data* – In conjunction with the more thorough review and use of information from the 2015 BNL report, ADEC conducted a survey of Fairbanks heating oil appliance companies to quantify local oil boiler/furnace maintenance intervals and costs and compare them to those for the northeastern U.S. reflected in the BNL report.**

6. ***Impacts of Changes in Heating Oil Market Prices* – When the ULSD CE analysis was performed for the 2020 Amendments (circa 2019/2020), Fairbanks heating oil prices were below $3/gallon. In 2022 they rose to over $5/gallon. Thus, the revised CE analysis was expanded to look at impacts on ULSD cost effectiveness when market prices of baseline heating oil vary between a range of roughly $3 to $5/gallon that reflects historical volatility in heating oil prices in Fairbanks over the last 15 years.**

7. ***Impacts of Relative vs. Additive ULSD Price Increases* – Under the CE analysis for the 2020 Amendments, ULSD price increases (relative to baseline #2 fuel oil) were applied as additive increments. Historical price data suggest the ULSD price premium may not be fixed and may similarly vary as the baseline #2 fuel oil market price changes. This revision evaluates application of the ULSD price difference on a relative rather than additive basis.**

8. ***Impacts of Changes in Baseline Heating Oil Sulfur Content* – In conjunction with the 2020 Amendments to the Serious SIP, the State of Alaska adopted and implemented regulation 18 AAC 50.078(b) requiring refiners to produce and sell only #1 fuel oil (1,000 ppm sulfur or less) beginning on September 1, 2022. The revised analysis looks at the cost-effectiveness of ULSD relative to baseline fuels of both #2 and #1 fuel oil given non-linearities in emission reductions and costs relative to the baseline fuel.**

The additive price impact scenarios included in this revised analysis likely represent smaller price increments than exist under high oil market price conditions. Using these more conservative (i.e., understated) additive price premiums, the combined ULSD cost-effectiveness was calculated to range from $58,252/ton under low baseline oil market prices to $73,816/ton under high baseline oil market price conditions that currently exist in early

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[99] J. Batey (Energy Research Center) and R. McDonald (Brookhaven National Laboratory), "Ultra Low Sulfur Home Heating Oil Demonstration Project Summary Report", prepared for New York State Energy Research and Development Authority, Report No. BNL-108353-2015-IR (2015).

<u>2023, under revisions 5 and 6. Details of ADEC's analysis methodology and calculations are included in the documents and spreadsheets included in the ULSD Appendix.</u>

<u>Technological Feasibility – EPA Final Rule and Comments</u>
<u>EPA did not find the updated technical information sufficient to overturn the States's "initial technological evaluation" included in the initial BACM analysis supporting the Serious Area Plan. EPA noted that ULSD is currently used in the Fairbanks Nonattainment Area and found "it self-evident that it is technologically and logistically feasible for some amount of the fuel" to be currently available.</u>

<u>EPA received several comments that questioned the technological feasibility of mandating ULSD use for the residential and commercial fuel oil combustion source category. These commenters argued that supplying sufficient ULSD to interior Alaska was not logistically feasible considering constrained rail and highway capacity. In response to comments received from Petro Star[100] and Alaska on supply issues EPA encouraged the State and local utilities to consider options to minimize wintertime logistical and supply concerns, such as "building more local storage tanks or evaluating all transportation options and schedules."</u>

<u>EPA noted receiving references to economic challenges to refining ULSD locally but did not receive any economic data to support the assertion. In response to other comments on ULSD, EPA noted they had not received any reliable information indicating that ULSD is corrosive. Instead, EPA noted that available information indicates that ULSD is a cleaner fuel that requires less maintenance compared to higher sulfur fuel. Thus, ULSD would require less energy to maintain heating devices that use ULSD. In summary, supplying ULSD to the Fairbanks Nonattainment area is technologically feasible.</u>

<u>Economic Feasibility – EPA Final Rule and Comments</u>
<u>EPA agreed with some of Alaska's methodological revisions and disagreed with others. As a result, EPA produced a separate cost-effectiveness analysis that built off Alaska's comment but only incorporated those methods and variables EPA determined to be reasonable and well supported. Those calculations are included in the docket for the above-referenced Final Action.</u>

<u>Portions of Alaska's updated analysis that the EPA determined to be reasonable included:</u>
- **<u>Corrections to annual energy use provide a more accurate cost estimate of ULSD;</u>**
- **<u>Price premium revisions taking into account the updated cost estimate for device maintenance expenses for both baseline fuel and ULSD;</u>**
- **<u>Fuel oil fouling revisions from switching to ULSD significantly lowered the impact on fuel consumption from 10-12 percent to 1.5 percent;</u>**
- **<u>The upper-bound fuel cost of $5.10 per gallon;</u>**
- **<u>The annual cost for device maintenance for both the baseline fuel and ULSD based on a Fairbanks oil heating appliance survey; and</u>**

[100] Both Petro Star and Marathon provided comments on logistical considerations in supplying fuels to the Fairbanks market. Their comments are included in the EPA comment docket referenced above.

- **Boiler cleaning intervals for baseline fuel and ULSD based on the same survey.**

Portions of Alaska's analysis that EPA disagreed with included:

- **Weighting factors used to combine cost effectiveness estimates for SO_2 and $PM_{2.5}$ reductions were based on speciation values from monitoring data reflecting emissions from points sources, not air quality modeling mentioned in the 2007 EPA guidance on heavy-duty diesel sources;**
- **Elasticity values that presume the increased price of fuel oil resulting from the switch to ULSD will increase $PM_{2,5}$ emissions because there will be an instantaneous substitution of wood for fuel oil (the elasticity values used reflect long term behavior not the short term behavior addressed in the analysis); and**
- **ULSD should be calculated relative to the price of other fuel oil; a review of historic market prices did not support the finding.**

EPA's economic feasibility comments focused on the cost-effectiveness of SO_2, a precursor for $PM_{2.5}$ concentrations. EPA's estimates ranged from \$13,046/ton to \$22,893/ton of SO_2 reduced. Overall, EPA found Alaska's revised economic infeasibility analysis convincing.

With regard to Petro Star assertions that conversions from solid fuel devices to liquid fuel devices are insignificant, EPA noted that since 2016 Fairbanks had changed out 958 solid-fuel burning devices to oil-fired or natural gas-fired heating devices. These conversions will reduce directly emitted $PM_{2.5}$ but increase SO_2 emissions, hence justified EPA's interest in reducing SO_2 and related cost-effectiveness estimates of controls.

In summary, supplying ULSD to the Fairbanks Nonattainment area is economically infeasible.

Conclusion

The revised technological analysis of implementing ULSD in the Fairbanks Nonattainment area prepared by Alaska as being infeasible was rejected by EPA. The revised economic analysis prepared by Alaska was found by EPA to be acceptable. Adjustments to Alaska's economic analysis prepared by EPA produced lower \$/ton values that still demonstrated the measure to be economically infeasible for implementation in the Nonattainment Area.

Measure 52: Operation and Sale of Small "Pot Burners" Prohibited

Implementing Jurisdiction(s)

- State of Vermont

Regulation Weblink(s)

- http://dec.vermont.gov/sites/dec/files/aqc/laws-regs/documents/AQCD_Regulations_2016_Dec.pdf

Background

Section 5-221 Prohibition of Potentially Polluting Materials in Fuel, subsection 2. Used Oil, contains the following restriction:

> *Effective July 1, 1997, the burning of used oil in small fuel burning equipment described as "pot burners" or "vaporizing" burners shall be prohibited, as shall the retail sale of these burners.*

Neither the Borough nor the State have any regulations restricting the sale of small waste or used oil burners. ADEC regulations restrict the operation of waste oil appliances during Stage 1 and Stage 2 Alerts. The State has no additional controls addressing the sale or operation of waste oil appliances.

Analysis

Vermont regulations prohibit both the operation and sale of small waste oil burning devices. Neither Alaska nor the Borough prohibit the sale of small waste oil burning devices. ADEC has regulations that restrict the operation of waste oil devices during Air Quality Alerts. The analysis section of Measure 70 discusses the available waste disposal methods for used oil and identifies a potential environmental impact regarding any prohibition or regulation of used oil combustion.

Conclusion

Alaska has no regulations governing the sale or operation of waste oil appliances or the use of waste oil used as a heating fuel; therefore, the Vermont measures addressing waste oil are eligible for consideration as a 2020 Amendment Plan control measure. The analysis in Measure 70 identified a potential environmental impact and measures prohibiting or regulating the burning of used oil were determined to be technically infeasible due to environmental impacts. However, an economic analysis was also conducted and the results of a cost effectiveness analysis of this measure, presented in Step 4, show this measure is economically infeasible.

Measure 53: No Use Sale or Exchange of Used Oil for Fuel, unless it Meets Constituent Property Limits

Implementing Jurisdiction(s)

- State of Vermont

Regulation Weblink(s)

- http://dec.vermont.gov/sites/dec/files/aqc/laws-regs/documents/AQCD_Regulations_2016_Dec.pdf

Background

Section 5-221 Prohibition of Potentially Polluting Materials in Fuel, subsection 2. Used Oil, contains the following restriction:

> *No person shall cause or permit the use, purchase, sale or exchange in trade for use as a fuel in fuel burning equipment in Vermont of any used oil unless:*
>
> *(i) The used oil has constituents and properties within the allowable limits set forth in Table A of this section prior to blending except as provided in subsection (e) below. The Air Pollution Control Officer may prohibit the combustion of used oils containing constituents or properties not listed in* Table 9*of this section if he/she determines that combustion of such used oil may present an unreasonable risk to public health or welfare.*

Table 9. Used Oil Constituents and Properties (Prior to Blending)

Constituent/Property	*Allowable[1]*
Arsenic	*5 ppm maximum*
Cadmium	*2 ppm maximum*
Chromium	*10 ppm maximum*
Lead	*100 ppm maximum*
Flash Point	*Must be 100 degrees F or more*
Total Halogens	*1000 ppm maximum*
Polychlorinated Biphenyls (PCBs)	*< 2 ppm maximum*
Net Heat of Combustion	*8000 BTU/lb minimum*
1Note: units of parts per million (ppm) are by weight on a water free basis.	

Neither the State nor the Borough have regulations addressing the purchase, sale or exchange of used oil. They also do not have regulations setting limits on waste or used oil properties.

Analysis

Vermont regulations restrict the allowable content and transfer of waste oil used as heating fuel. There are no such restrictions governing waste or used oil as a heating fuel in Fairbanks. The analysis section of Measure 70 discusses the available waste disposal methods for used oil and identifies a potential environmental impact regarding any prohibition or regulation of used oil combustion.

Conclusion

Alaska has no regulations governing the content, use or transfer of waste oil used as a heating fuel; therefore, the Vermont measures addressing waste oil are eligible for consideration as a control measure for the 2020 Amendment to the Serious SIP. The analysis in Measure 70 identified a potential environmental impact and measures prohibiting or regulating the burning of used oil were determined to be technically infeasible due to environmental impacts. However, an economic analysis was also conducted and the results of a cost effectiveness analysis of this measure, presented in Step 4 show this measure is economically infeasible.

Measure 54: Adopt CARB Vehicle Emission Standards

Implementing Jurisdiction(s)

- California Air Resources Board(CARB)

Regulation Weblink(s)

- https://ww2.arb.ca.gov/our-work/programs/advanced-clean-cars-program/lev-program/low-emission-vehicle-lev-iii-program

Background

Under Section 177 of the federal Clean Air Act, states that choose to adopt vehicle standards that are more stringent than the federal standards for new vehicles can only adopt California's vehicle emission standards. To date 14 states have opted-in to California's vehicle emissions standards. The most current version of California's Low Emission Vehicle (LEV) III regulations limit greenhouse gases and traditional tailpipe pollutants (HC, CO, NOx and PM). These regulations were modified by California in 2015 to align the California and federal Tier 3 motor vehicle emission standards. The federal Tier 3 rules were finalized in 2014 by the U.S. EPA and reduced tailpipe and evaporative emissions from passenger cars, light-duty trucks, medium-duty passenger vehicles and allowable emissions from heavy-duty vehicles. The California LEV III and federal Tier 3 regulations are consistent from model year 2017 through 2024 for particulate emissions. Starting in 2025, however, the stringency of the LEV III standards will be increased from 3 mg/mi to 1 mg/mi, while the federal Tier 3 standards will remain at 3 mg/mi. Thus, an extremely small reduction in motor vehicle particulate emissions (i.e., 2 mg/mi) will become available in late 2025 and succeeding years.

Analysis

To put 2 mg/mi reduction into perspective, 1 million miles of travel by vehicles meeting the more stringent 2025 – 2028 LEV III particulate emission standards would produce a reduction of 4.4 lbs. Several factors must be considered when assessing the benefit of adopting the LEV III standards, including:

a. An analysis of the most recent DMV registrations (April 2018) showed the statewide population of vehicles was 644,312 and a total of 97,600 were registered in Fairbanks. Assuming vehicle ownership is proportional to population, the number of vehicles registered in the nonattainment area is 82,980. Since Alaska would be required to adopt the CARB vehicle standards on a statewide basis, it means 87% of the light duty passenger cars and light-duty trucks sold each year starting in 2025 would be required to meet the more stringent standards without a supporting mandate.

- Assuming wintertime driving travel is roughly 50 miles per vehicle per day (more than twice the value employed in the Fairbanks travel demand model forecasts), it would take 20,000 vehicles to produce 4.4 lb/day reduction in PM emissions. Assuming the 2 mg/mi reduction applied to the entire vehicle fleet, which it does not because the California and federal emission standards for medium/heavy duty vehicles are equivalent through this period, the total reduction potential within the Fairbanks PM nonattainment area would be on the order of 18 lbs per day (in reality less).

The magnitude of the emission reduction potential must be considered in light of the disproportionate impact on the rest of the Alaska vehicle fleet. Recently, the federal government has proposed to rollback the California vehicle emission standards for Model Years 2021 – 2026, so the availability of the basis for this measure is in question. In addition, a review of the literature about the costs of implementing the California vehicle emission standards shows there is considerable controversy. Assuming that the net cost between increased new vehicle price versus improved fuel economy and lowered fuel consumption is zero, Oregon, which adopted the California vehicle emission standards estimated that the administrative cost of complying with the California vehicle emission standards is $5.43/vehicle.[101] Using that price and the 2 mg/mile PM benefit over the 100,000 mile certified life of the emission control system would produce a cost effectiveness estimate of $25,000/ton of PM removed. Since Oregon's population is 5.5 times larger than Alaska's (based on a comparison of 2018 populations), it means that administrative cost estimate would be distributed over a significantly smaller fleet of new vehicle sales in Alaska and the administrative of cost of adopting California vehicle emission standards would be significantly higher than the $25,000/ton estimate. Given this information, the statewide adoption of the CARB LEV III emission standards is not cost effective and is not warranted for the Fairbanks $PM_{2.5}$ nonattainment area.

Conclusion

The minimal Fairbanks emissions benefit from a statewide adoption of CARB LEV III emission standards is not cost effective and therefore not eligible for consideration as a measure for the 2020 Amendment to the Serious SIP.

Measure 55: School Bus Retrofits

Implementing Jurisdiction(s)

- Oregon Department of Environmental Quality, Lane Regional Air Protection Agency

Regulation Weblink(s)

- https://www.gpo.gov/fdsys/pkg/FR-2017-11-14/html/2017-24539.htm

[101] https://www.oregon.gov/deq/Rulemaking%20Docs/levzev2018fis.pdf

- http://www.lrapa.org/DocumentCenter/View/2108

Background

The RACM analysis in the Oakridge, Oregon Moderate $PM_{2.5}$ attainment plan lists Diesel retrofits of school buses as a primary control measure. No specific emissions credit, however is listed for this measure. The 2016 update to the SIP, which EPA proposed for approval, lists implementing diesel retrofits of school buses as a local transportation control measure. It also states:

> *No specific credit was taken for these mobile source programs in the 2015 attainment year emission inventory other than the normal reductions over time included in the MOVES2014a modeling.*

Neither Fairbanks nor the state has a regulation mandating the replacement of Diesel powered school buses. The Fairbanks RACM analysis evaluated *retrofit of diesel fleet (school buses, transit)* as a transportation control measure. The measure was determined to be technologically infeasible as were all measures listed in the category of transportation controls.

Analysis

EPA offers funds for the replacement of Diesel school buses through its Clean Diesel Program. The Diesel Emissions Reduction Act (DERA) provides grants for projects that reduce emissions from existing diesel engines. DERA has funded numerous diesel replacement projects in Alaska. DERA funds are currently being used to replace five diesel generators in four rural communities in Alaska. Other programs have funded diesel garbage truck, power generation and school bus replacement projects. The most recent diesel replacement program conducted in Fairbanks is a joint DEC/DOT&PF project[102] that replaced three heavy duty construction trucks, placed in service by the State of Alaska in 1986. That project was completed in 2010.

Oregon has funded several school bus replacement programs and included them in the Oakridge RACM analysis for the Moderate SIP, which EPA has proposed to approve. That plan, however, takes no specific emissions credit for the program and states that its benefits are included in fleet turn over benefits tracked by EPA's motor vehicle emissions simulator model (MOVES)2014b.

The Fairbanks North Star School District confirmed[103] that the school bus contractor will change in August 2021 and that the entire fleet of Diesel school buses will be replaced with gasoline powered school buses by the end of that month. The primary reason for the change is that gasoline engines warm up more rapidly than Diesel engines and they in turn provide more rapid and efficient heating for passengers; another benefit is that operating costs will decline because of the difference between gasoline and Diesel fuel prices. A side benefit of this change is that PM emission from gasoline vehicles is significantly lower than for Diesel vehicles, therefore school bus retrofits contemplated under this measure would increase not decrease PM emissions.

[102] http://dec.alaska.gov/air/anpms/projects-reports/akdot
[103] Telephone conversation between Dwane Taylor of the Fairbanks North Star Borough School District and Robert Dulla, Trinity Consultants, on behalf of ADEC, August 18, 2020

Conclusion

Since the conversion from gasoline to Diesel powered school buses contemplated by this measure would increase PM emissions, this measure is technologically infeasible and not eligible for consideration as a measure for the 2020 Amendment to the Serious SIP.

Measure 56: Road Paving

Implementing Jurisdiction(s)

- Klamath Falls, Oregon

Regulation Weblink(s)

- http://www.oregon.gov/deq/FilterDocs/KFallsAttPlan2012.pdf

Background

The 2012 $PM_{2.5}$ attainment plan for Klamath Falls includes a road paving control measure. The analysis lists road paving as an existing control measure and states:

> *PM2.5 emissions generated by motor vehicle traffic have been reduced over the years through efforts to pave roads, minimize the use of sanding material, and to control mud and dirt track out from industrial, construction and agricultural operations. Six miles of unpaved road have been paved in the nonattainment area since 2008, resulting in reductions from re-suspended road dust.*

The $PM_{2.5}$ emission reduction benefit of road paving is listed as "minimal".

Alaska does not have an emissions control measure addressing road paving in urban areas. An analysis[104] prepared in 2006 identified road paving as a fugitive dust control measure for implementation in rural communities in Alaska. Fairbanks has no control measures addressing road paving. Unlike many communities in the lower-48, roads in the Fairbanks nonattainment area remain frozen during winter months. The emissions inventory discussion in Step 1 noted that fugitive dust sources of $PM_{2.5}$ are estimated to be negligible under the snow/ice bound conditions reflected in the winter seasonal inventory.

Analysis

The Klamath Falls SIP claims "minimal" $PM_{2.5}$ emission benefit for a fugitive dust control measure. Since fugitive dust emissions in Fairbanks are negligible during the winter, the application of fugitive dust controls with "minimal" benefits in a more moderate climate will produce no benefits.

[104] *https://dec.alaska.gov/air/anpms/Dust/Dust_docs/DustControl_Report_032006.pdf*

Conclusion

Fugitive dust control measures will provide no wintertime $PM_{2.5}$ benefit in Fairbanks, therefore it is technologically infeasible and not eligible for consideration as a measure for the 2020 Amendment to the Serious SIP.

Measure 57: Other Transportation Control Measures

As noted in the Step 2 discussion, Measures 57 & 59 are addressed in the Measure R20 Transportation Control Measure feasibility analysis.

Measure 58: Controls on Road Sanding and Salting

Implementing Jurisdiction(s)

- Utah Department of Environmental Quality

Regulation Weblink(s)

- https://documents.deq.utah.gov/air-quality/pm25-serious-sip/DAQ-2017-011685.pdf
- https://documents.deq.utah.gov/air-quality/pm25-serious-sip/DAQ-2017-011686.pdf
- https://documents.deq.utah.gov/air-quality/pm25-serious-sip/DAQ-2017-011687.pdf

Background

Draft BACM analyses for the Logan, Provo, and Salt Lake Areas in Utah's Serious $PM_{2.5}$ SIP has identified Road Salting & Sanding as a control measure. The analysis prepared for each community included the following finding:

> *R307-307 Road Salting & Sanding: The purpose of this rule is to establish emission control for wintertime road salting. This is an existing rule that was part of the PM10 SIP (Section IX, Part A, Page 57) that was approved by EPA on December 6, 1999 (64 FR 68031). A RACT analysis was conducted as part of that SIP. The rule was amended by expanding the applicability to include $PM_{2.5}$ nonattainment areas as part of the moderate $PM_{2.5}$ SIP. The actual PM emission reduction is unknown however, past UDAQ studies have indicated that road salt plays a minimal role related to this SIP. Consequently, no further analysis is warranted.*

Fairbanks and Alaska do not have an emissions control measure addressing either road sanding or road salting. Unlike many communities in the lower-48, roads in the Fairbanks nonattainment area remain frozen during winter months. The emissions inventory discussion in Step 1 noted that fugitive dust sources of $PM_{2.5}$ are estimated to be negligible under the snow/ice bound conditions reflected in the winter seasonal inventory.

Analysis

Utah is planning to expand the applicability of the Road Sanding & Salting control measure, a PM_{10} fugitive dust control measure, to the Logan, Provo and Salt Lake $PM_{2.5}$ nonattainment areas. The analysis states that the $PM_{2.5}$ benefit of the measure is "unknown" and no credit is taken for the measure.

Since fugitive dust emissions in Fairbanks are negligible during the winter, the application of fugitive dust controls with "unknown" benefits in Utah's more moderate climate will produce no benefits in Fairbanks.

Conclusion

Fugitive dust control measures will provide no wintertime $PM_{2.5}$ benefit in Fairbanks, therefore this measure is technologically infeasible and not eligible for consideration as a measure for the 2020 Amendment to the Serious SIP.

Measure 59: I/M Programs

As noted in the Step 2 discussion, Measures 57 & 59 are addressed in the Measure R20 Transportation Control Measure feasibility analysis.

Measure 60: Vehicle Idling Restrictions

Implementing Jurisdiction(s)

- **Many – EPA published a report summarizing state and local idle control programs in 2006.[105]**

Regulation Weblink(s)

- **None**

Background

In the 2020 Amendments to the Serious SIP, ADEC reviewed EPA's compilation of anti-idling regulations from 31 different states. A review of the regulations listed in the report found the programs were focused on controlling heavy-duty vehicle activity for a variety of reasons, including noise, fuel consumption and emissions. Controls addressing light-duty vehicle activity were conspicuously absent. A literature review and related searches could find no SIPs taking particulate emissions credit for anti-idling programs. ADEC also noted that emission control system performance deteriorates at colder temperatures when

[105] EPA, EPA420-B-06-004, *Compilation of State, County and Local Anti-Idling Regulations* (April 2006).

engines are turned off and catalysts cool down.[106] A study by Sierra Research[107] found there was little or no CO benefit from turning off a warmed-up vehicle if it was going to be started again within an hour. An analysis of a series of related studies conducted by Sierra Research[108] found that catalytic control of PM emissions parallels the control of CO emissions, and therefore the impact of idle control on CO emissions has a similar impact on PM emissions. This led to the conclusion that idle restrictions during winter conditions in Fairbanks would produce no particulate emissions benefit. Based on these findings, and the fact that no SIPs have taken credit for particulate emissions reduction from anti-idling programs, the measure was determined to be technologically infeasible and dismissed as a control measure for the 2020 Amendments to the Serious SIP.

In their comments on the 2020 Amendments in the Proposed Partial Approval and Partial Disapproval, EPA stated that ADEC's conclusion lacked sufficient feasibility assessment.[109] EPA explained that ADEC could not rely on its determination that measures would not provide sufficient emission reduction benefits because that appeared to apply a de minimis source category concept that is inapplicable to the $PM_{2.5}$ NAAQS implementation. According to EPA, ADEC did not explain how measures could not be implemented due to local conditions, lack of infrastructure or cost-effectiveness.[110]

In comments on EPA's Partial Disapproval of the Fairbanks Serious SIP, ADEC explained that it did not rely on the de minimis source category concept to dismiss control measures before a BACM analysis was completed.[111] Instead, ADEC dismissed anti-idling controls as technologically and economically infeasible, following the five-step BACM process consistent with the Final $PM_{2.5}$ Rule and applicable law.

Consistent with BACM Step Three, ADEC analyzed the technological feasibility of anti-idling controls.[112] ADEC stated that a key consideration at Step Three is whether idle controls provide an emissions benefit beyond those provided by existing federal, state and local controls.[113] ADEC's analysis relied on: (1) local conditions; (2) survey results reflecting local workforce habits; (3) findings drawn from studies with parallel EPA-approved assessments; (4) the fact that no SIP has relied on taking particulate emissions credits for anti-idling programs to determine that such measures would be technologically

[106] ADEC Air Quality Control Plan, Vol. III: Appendix III.7.7-5405 (Adopted Nov. 18, 2020), at 68.
[107] Di Genova, F., et al, "Fairbanks Cold Temperature Vehicle Testing: Warmup Idle, Between-trip Idle, and Plug-in," prepared for Alaska Department of Environmental Conservation by Sierra Research, January 2002.
[108] DiGenova, F. et al, "Characterizing Vehicular Contributions to PM2.5 in Fairbanks, Alaska, Volume 1: Dynamometer-Based Emissions Measurements, Vehicle Keep-warm Activities and MOVES Analysis, December 2012 (Volumes 1 – 4).
[109] 88 Fed. Reg. at 1481; *see also* Technical Support Document at 32, 33, 45-46.
[110] Technical Support Document: Docket No. EPA-R10-AOAR-2022-0115, at 32.
[111] ADEC, EPA, and FAST Planning all document EPA's incorrect treatment of EPA's assertion. *See* Letter from Jackson C. Fox, Executive Director, FAST Planning, to U.S. EPA Region 10, "Air Plan Partial Approval & Disapproval, 2006 24-hour PM2.5 Serious Area and 189(d) Plan, Fairbanks North Star Borough, Alaska," at 2 (Feb. 15, 2023) (hereinafter "FAST Planning Comment Letter").
[112] 2020 BACM Analysis at 5399-5406, 5435-5438.
[113] 2020 BACM Analysis at 5355; *see* 40 C.F.R. § 51.1010(a)(3)(iii) (requiring state's feasibility criteria to be more stringent than criteria for determining RACM for same sources in nonattainment area).

infeasible because they produce no particulate emissions benefit.[114] ADEC relied on case-specific, local factors and data in determining whether the identified control measures would provide a quantifiable emissions benefit, alongside an analysis of EPA's prior actions in approving nonattainment plans submitted by two other regions (South Coast Air Basin, and San Joaquin Valley) that rejected certain control measures on technological infeasibility grounds similar to Alaska.

Consistent with BACM Step Four, ADEC performed an economic feasibility evaluation for an anti-idling program for heavy-duty vehicles.[115] It reviewed information collected during a CMAQ-funded pilot program, conducted in partnership with the Alaska Department of Transportation and Public Facilities. Based on estimated costs and emission rates, ADEC estimated the cost-effectiveness of idle controls for heavy-duty vehicles to be $455,675.88 per ton of $PM_{2.5}$ reduced, and therefore determined that measure to be economically infeasible.

ADEC also performed an economic feasibility evaluation for two anti-idling programs for light-duty vehicles: (1) patrolling commercial establishments such as grocery stores, restaurants, bars, and shopping centers where people idle their vehicles, and (2) an anti-idling campaign targeted at passenger vehicles during pick-up and drop-off periods at schools. The cost-effectiveness of patrolling parking lots of commercial establishments was estimated to range between $20,420,145 to $10,837,330,902 per ton of $PM_{2.5}$ reduced. The range represents different establishments, time-of-day and day-of-week variability in people parking at them. The cost-effectiveness of school programs was estimated to be $201,198,489 per ton of $PM_{2.5}$ reduced. ADEC determined both measures to be economically infeasible.

In their Final Rule, EPA accepted ADEC's economic infeasibility determination rejecting idling restrictions for heavy-duty diesel vehicles, but disapproved Alaska's rejection of vehicle idling restrictions at schools and commercial establishments.[116]

EPA acknowledged that ADEC did not explicitly designate the mobile source category as a de minimis source category in the Fairbanks Serious Plan and the Fairbanks 189(d) Plan for the purposes of avoiding and implementing BACM and BACT on mobile sources.[117] EPA proposed to disapprove ADEC's rejection of idling restrictions based on several factors, including: (1) low emissions benefits is not a valid basis to reject a measure as technologically infeasible; (2) BACM determinations are generally independent of attainment, and (3) ADEC's rejection of all measures to control emissions from mobile sources appeared to implicitly determine that this category was de minimis.[118]

In the Final Rule, EPA summarized how ADEC concluded that anti-idling programs are technologically infeasible due to a lack of evidence of emission benefits by drawing parallels

[114] 2020 BACM Analysis at 5405-5406
[115] 2020 BACM Analysis at 5310–5311.
[116] 88 Fed. Reg. 84626, at 84649 (Dec. 5, 2023).
[117] 88 Fed. Reg. at 84650.
[118] *Id.*

between low CO emissions benefits and low PM benefits.[119] EPA responded that the emissions reduction benefit of a particular measure is not a factor in whether the measure is technologically feasible, and such considerations are more appropriate under an economic feasibility assessment.[120] EPA summarized the substantive basis for ADEC's rejection of transportation control measures, including anti-idling, as being that the measures provided limited emissions benefits, such benefits were difficult to quantify given the climate in Fairbanks, and/or that additional studies were necessary to understand the emissions reduction benefits.[121] EPA asserted that these are inadequate reasons for rejecting what it perceived to be otherwise feasible measures.[122]

EPA disagreed with ADEC's assertion that EPA has applied the $PM_{2.5}$ SIP Requirements Rule inconsistently and discussed other recently approved SIPs in California as evidence. EPA briefly discussed its prior approvals of mobile source category controls for ADEC's Moderate Plan and noted that BACM goes beyond RACM.

With respect to ADEC's supplemental analysis of vehicle anti-idling controls at schools and commercial establishments, EPA considered ADEC's supplemental economic infeasibility assessment, as well as ADEC's comment that imposing those restrictions would pose an unacceptable safety risk.[123] ADEC commented that it had significant safety concerns regarding control measures for light-duty vehicle anti-idling, and when temperatures are -20°F to -60°F, idling is often done to ensure that small children and infants aren't exposed to frostbite conditions or to prevent cars from being stranded after being turned off without being plugged in to a heat source.[124] In its Final Rule[125], EPA responded that other state and local anti-idling restrictions include idle duration limits that vary depending on ambient temperature and provide exemptions for safety. EPA noted that ADEC may adopt an anti-idling regulation that takes into consideration the unique local conditions in the Fairbanks $PM_{2.5}$ Nonattainment Area.[126]

EPA stated that ADEC "did not provide data supporting the prevalence of cars failing to start or run in cold weather in the Fairbanks nonattainment area."[127] EPA stated that it "searched for documentation of this issue and could not find any studies or data."[128] EPA referenced an Alaska Department of Transportation source saying that frequent engine restarts have little impact on engine components and unnecessary vehicle idling can damage engine components and waste fuel. EPA reviewed its public hearing transcript and noted that one commenter raised concerns about electric vehicles failing to work in cold weather, which was contradicted by another who testified to owning an electric car that

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[119] *Id.*
[120] 88 Fed. Reg. at 84650–84651.
[121] 88 Fed. Reg. at 84651.
[122] *Id.*
[123] 88 Fed. Reg. at 84652.
[124] *Id.*
[125] *Id.*
[126] *Id.*
[127] *Id.*
[128] *Id.*

functions in -30°F.[129] Overall, EPA decided that ADEC had not demonstrated that vehicle anti-idling restrictions for light-duty vehicles at schools or commercial establishments are technologically infeasible.[130] EPA reiterated that ADEC may craft the measure in a manner that accommodates safety concerns.[131]

With regard to ADEC's economic infeasibility demonstration, EPA noted that the calculations included the annual salaries of two Fairbanks North Star Borough employees to patrol parking lots to enforce the program.[132] EPA found that incorporating the cost of implementing and enforcing a control strategy is inconsistent with the CAA and $PM_{2.5}$ SIP Requirements Rule. EPA found that when these costs were removed from the calculation the measure appears to yield cost savings. EPA concluded that ADEC had not demonstrated that vehicle anti-idling restrictions for light-duty passenger vehicles at commercial establishments and schools are economically infeasible.

After dismissing ADEC's technological and economic feasibility findings, EPA encouraged the state to adopt and implement an anti-idling regulation and incorporate it into a subsequent SIP submission.

Analysis

EPA's Final Rule indicated that the "emissions reduction benefit of a particular measure is not a factor assessing whether the measure is technologically feasible."[133] Thus, the assessment of technological feasibility must focus on implementation issues, which include local conditions, and responding to EPA's comment that ADEC did not provide a demonstration that vehicles have difficulty starting or running at cold temperatures in the Fairbanks nonattainment area. The assessment of the emissions reduction benefit will be addressed in the economic feasibility analysis.

a. Technological Feasibility and Cold Temperature Startability

A key consideration in the assessment of local conditions is the temperature at which the anti-idling measure should be implemented. EPA noted that a review of anti-idling restrictions at other areas illustrated a variety of approaches to limit idling and encouraged ADEC to adopt a regulation that takes into consideration the unique local conditions in the Fairbanks nonattainment area.[134]

EPA's comment regarding the issues with starting and running vehicles in cold temperatures is irrational, and reinforces that, despite having worked on air quality issues in Fairbanks for decades, EPA Region 10 refuses to acknowledge the unique circumstances in a subarctic region and provide Fairbanks with the regulatory flexibility granted in the

[129] 88 Fed. Reg. at 84652–84653.
[130] 88 Fed. Reg. at 84653.
[131] *Id.*
[132] *Id.*
[133] 88 Fed. Reg. at 84653.
[134] 88 Fed. Reg. at 84652.

CAA and the $PM_{2.5}$ Implementation Rule. In the extreme cold temperatures of -40 degrees Fahrenheit, routinely experienced in Fairbanks, the challenges to start and run a vehicle are amplified even further.

Despite EPA's comment that it could not find evidence of cars failing to start or operate at colder temperatures,[135] there is substantial evidence that this is a major consideration for vehicle operation during arctic winter conditions experienced in Fairbanks and North Pole.[136] In cold weather, less electrical current is generated in the vehicle's battery, which provides less power to the starting motor. As temperatures drop, viscosities of fluids within the vehicle increase. The higher viscosities require more work from the starting motor to circulate the fluids and start the vehicle. At lower temperatures, gasoline can't vaporize to form a combustible temperature. The combination of these physical limitations results in failed starts.

A well-established behavior is for most vehicles to be equipped with block heaters, oil pan heaters, and/or battery heaters/trickle chargers to be able to operate during winter months in Fairbanks; visual evidence can be seen in the electric cords that extend outside of engine hoods of light-duty vehicles. Block heaters provide supplemental heat to ensure that the fuel (i.e., gasoline) can vaporize and form a combustible mixture at colder temperatures. Oil pan heaters provide supplemental heat to the lubricating fluids necessary for engine operation. Battery heaters and trickle chargers ensure sufficient electrical current can be supplied to the starting motor.

Historically, the principal reason for equipping vehicles with block heaters, oil pan heaters, and battery heaters/trickle chargers has been to aid startability for safety, and their emission reduction effects are a side benefit. Recognition of both emissions and safety benefits is reflected in the EPA-approved Borough Ordinance for a vehicle plug-in program, which requires parking lot owners to power electrical outlets for these winterization components at 21 degrees Fahrenheit or lower.[137] That temperature is traditionally the threshold at which vehicle owners begin plugging in these winterization elements on their vehicles to ensure startability; a safety concern.

EPA's statement in its final decision that "Alaska did not provide data supporting the prevalence of cars failing to start in cold weather"[138] is akin to stating that Alaska did not

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135 *Id.*
136 US Department of Defense. Alaska Extreme Cold Tests Soldiers, and Equipment. Accessed at https://www.defense.gov/News/News-Stories/Article/Article/1090533/alaskas-extreme-cold-tests-soldiers-equipment/; News Articles on Vehicle Performance and Starting Issues in Alaska. Accessed at https://cowboystatedaily.com/2024/01/12/aaron-turpen-why-cars-struggle-to-start-in-the-cold/, https://www.alaskacartransport.com/news/common-car-battery-issues-in-alaska/, https://www.thedieselstop.com/threads/alaska-cold-weather-remote-start-problems.186587/, https://www.webcenterfairbanks.com/content/news/Cold-Weather-Tips-Are-your-vehicles-prepared-566765211.html.
137 Fairbanks North Star Borough Code Ordinance 21.24.010. Accessed at https://fnsb.borough.codes/FNSBC/21.24.010. This Ordinance was amended from the 2001 FNSB Ordinance 2001-17, and EPA approved at https://www.gpo.gov/fdsys/pkg/FR-2002-02-04/pdf/02-2505.pdf#page=1. The 21.24.010 was approved by the EPA as part of III.III.D.7.13 Appendix to Assurance of Adequacy, 88 Fed. Reg. at 84675.
138 88 Fed. Reg. at 84652.

provide data supporting its assertion that the sky is blue. Studies of this phenomenon do not abound because it is simply a physical fact. EPA's continued statement that EPA "searched for documentation of this issue and could not find any studies"[139] demonstrates EPA's refusal to acknowledge the unique local circumstances while evaluating the technical feasibility of control measures under BACM, which is not only allowed but required in the Final $PM_{2.5}$ Implementation Rule.[140]

Another example of cold temperature startability concerns in the Fairbanks nonattainment area is the use of "auto starts," a technology wherein vehicle owners can start their vehicles remotely to ensure that the windows are defrosted for visibility and the vehicle interior is warm when they return to the vehicle. Based on a conversation with a company that installs the auto start technology, roughly 20+% of light-duty vehicles in Fairbanks are equipped with auto-starts.[141] Earlier, vehicle owners had to select the default ambient temperature thresholds at which the vehicles automatically start. The technology has since then evolved and most systems now simply remote start on command when people want to warm their vehicles.

Furthermore, contrary to EPA's apparent confusion about cold starts and operation of electric vehicles,[142] well-established studies in the literature have documented the effects of low temperatures on electric vehicles.[143] The main concern identified by these studies is the limited driving ranges for electric vehicles at low temperatures.[144] At extreme cold temperatures like those in ordinary Fairbanks winters, "[b]atteries get zapped of their charge."[145]

In sum, Alaska does not agree with EPA's final determination that light duty vehicle idling is technologically feasible, because EPA's reasoning is flawed. Nevertheless, Alaska has no delusions that EPA will reverse its decision and is continuing the BACM analysis by proceeding to Step 4 to assess the economic feasibility of the control measure.

b. Economic Infeasibility

In the Final Rule, EPA noted that Alaska may craft an anti-idling control measure for light-duty vehicles in a manner that accommodates safety concerns.[146] Based on an assessment of local conditions, idling restrictions could be implemented at temperatures of 21°F and above. The Borough Ordinance on vehicle plug-in program demonstrates that

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139 *Id.*
140 81 Fed. Reg. at 58084.
141 Conversation with Greg Cambell at Interior Remote Start today (https://interiorremotestart.com/) by Robert Dulla, Trinity Consultants, on behalf of ADEC. Date January 18, 2024.
142 88 Fed. Reg at 84652–84653.
143 J. R. M. Delos Reyes, R. V. Parsons and R. Hoemsen, 2016 "Winter Happens: The Effect of Ambient Temperature on the Travel Range of Electric Vehicles," in *IEEE Transactions on Vehicular Technology*, vol. 65, no. 6, pp. 4016-4022, doi: 10.1109/TVT.2016.2544178. Steinstraeter, M., Heinrich, T., & Lienkamp, M. 2021. Effect of Low Temperature on Electric Vehicle Range. *World Electric Vehicle Journal*, doi: 10.3390/wevj12030115.
144 *Id.*
145 Alex Horton, *In Alaska, American commandos game out a great-power war*, Washington Post, April 14, 2024.
146 88 Fed. Reg. at 84653.

the need for supplemental heat begins at 21°F and below when thermal inversion often occurs, and idling restrictions at temperatures below that threshold are a safety concern. As such, Alaska's economic feasibility analysis is based on implementation at temperatures of 21°F and above.

ADEC revised the economic feasibility analysis from the ADEC's response to EPA's Partial Disapproval of the Fairbanks Serious SIP and its 2020 Amendments by including a temperature exemption in implementing (1) patrolling at commercial establishments where people idle, and (2) an anti-idling campaign at schools during school pick-up and drop-off periods. The analysis focused on implementing idling restrictions during winter months from October through March at temperatures above 21°F, a temperature threshold below which restrictions would pose safety concerns based on a review of local conditions.

For patrolling at commercial establishments, ADEC reached out to local establishments to estimate the average number of people visiting per day, and researched online for the average times spent by people at these establishments. Based on good engineering judgment considering local conditions in Fairbanks, and conversations with ADEC staff about their observations, ADEC assumed 50% of people switch off their vehicles completely, 25% of people use auto-starts, and 25% of people idle their vehicles at these establishments. ADEC assumed a 38% reduction in average idling time based on literature,[147] and a compliance rate of at 50%. The costs to implement the program consisted of having two Borough staff members for patrolling, fuel costs for driving around the nonattainment area, and fuel savings costs from reduced idling at local establishments. Based on the local data, cost estimates, light-duty vehicle fleet $PM_{2.5}$ idle emission rates, and fuel consumption rates developed using the MOVES3 model, ADEC estimated the cost-effectiveness for idling restrictions above 21°F at commercial establishments to range between \$34,618,384 to \$3,488,366,984 $PM_{2.5}$ reduced. The range represents different commercial establishments, including restaurants and bars, grocery stores, and shopping centers.

For conducting an anti-idling campaign at schools, ADEC obtained information from EPA's idle-free schools toolkit[148] and the National Center for Education Statistics.[149] Similar to patrolling at commercial establishments, ADEC assumed a 38% reduction in average idling time at schools and assumed a compliance rate of 50%. The program costs included staff costs to implement the campaign, printing costs for pledge forms, brochures, and no-idle sign boards, and fuel-saving costs from reduced idling. Based on these assumptions, cost estimates, emissions, and fuel consumption rates developed from the MOVES3 model, ADEC estimated the cost-effectiveness for idling restrictions above 21°F at schools to be \$390,357,271 per ton of $PM_{2.5}$ reduced.

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[147] Daniel L. Mendoza, et al., Air Quality and Behavioral Impacts of Anti-Idling Campaigns in School Drop-Off Zones. Atmosphere, 2022; 13 (5): 706 DOI: 10.3390/atmos13050706.
[148] U.S. EPA, "Idle-Free Schools Toolkit for a Healthy School Environment," Accessed at https://www.epa.gov/schools/idle-free-schools-toolkit-healthy-school-environment.
[149] National Center for Education Statistics, "Public Schools in Fairbanks North Star Borough School District," Accessed at https://nces.ed.gov/ccd/schoolsearch/school_list.asp?Search=1&County=Fairbanks%20North%20Star%20Borough&State=02&SchoolPageNum=3.

As its basis for disapproval, EPA writes that "[i]ncorporating the cost of implementing and enforcing a control strategy is inconsistent with the CAA and $PM_{2.5}$ SIP Requirements Rule."[150] This is incorrect. EPA cites CAA section 110(a)(2)(E) as a reference for not allowing the cost of implementing and enforcing a control strategy to be considered in an economic analysis. CAA section 110(a)(2)(E) does require that the State have adequate personnel and funding to carry out its implementation plan, but it does not state that implementation and enforcement costs borne by the State cannot be considered in an economic assessment. The economic analysis under BACM and assurances of adequacy to carry out an implementation plan are two separate and distinct requirements, and the latter is not a basis for EPA to disapprove this economic infeasibility analysis.

EPA states that "economic infeasibility assessments are focused on the costs projected to be borne by the owner and operator of the subject source,"[151] and cites 40 CFR 51.1010 and 81 Fed. Reg. at 58085. But these references do not support this assertion. 40 CFR 51.1010 is silent on which entity bears the economic burden and only provides a non-exhaustive list of factors that may be considered. It states that for "purposes of evaluating the economic feasibility of a potential control measure, the State may consider capital costs, operating and maintenance costs, and cost effectiveness of the measure." It does not say that the reasonable costs of implementation cannot be included in that cost effectiveness calculation. The same is true of the description of the economic feasibility assessment step at 81 Fed. Reg. at 58085.

The metric used to compare costs across sources is cost effectiveness, which EPA defined in the preamble to the $PM_{2.5}$ SIP Requirements Rule as the annualized cost ($/year) divided by the emissions reduced (tons/year) which yields a cost per amount of emission reduction ($/ton).[152] EPA further states that cost effectiveness provides a relative value for each emissions reduction option that is comparable with other options.[153] EPA provides a non-exclusive list of factors that may be considered when developing the economic analysis in 40 CFR 51.1010[154] and clearly indicated that case specific factors are appropriate in determining the economic feasibility of potential control measures.[155] Under BACM the preamble states that the fourth step of this process is to evaluate the costs of implementing each of the technologically feasible control measures.[156] EPA goes on to define "implement" to mean that the control measure has not only been adopted into the SIP for the area but has also been built, installed and/or otherwise physically manifested and the affected sources are required to comply.[157] These references indicate that the inclusion of implementation and operational costs is a valid consideration in evaluating the feasibility of a BACM.

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[150] 88 Fed. Reg. at 84653.
[151] *Id.*
[152] 81 Fed. Reg. at 58042.
[153] 81 Fed. Reg. at 58042.
[154] 81 Fed. Reg. at 58157.
[155] 81 Fed. Reg. at 58082.
[156] 81 Fed. Reg. at 58085.
[157] 81 Fed. Reg. at 58085.

In this case, vehicle idling restrictions are not a piece of equipment with a capital expenditure; the idling restrictions are an attempt to effect large scale behavior change through regulation. The emission reductions are entirely dependent on convincing a percentage of the public to change behavior, which is an enormous undertaking. Government employees designing the measure, managing the program, conducting outreach, and ensuring compliance are essential operating elements without which emission reductions are not realized and the control measure is not implemented. Therefore, including the cost of government employee salaries in the economic feasibility assessment is consistent with both the CAA and the $PM_{2.5}$ SIP Requirements Rule. Further, including the cost of government employee salaries in the economic analysis is essential to providing a representative economic analysis to compare control measures, which is a fundamental element of economic feasibility analyses as defined by the $PM_{2.5}$ SIP Requirements Rule.

EPA's basis for disapproval—that including the cost of implementing and enforcing a control measure is inconsistent with the CAA and $PM_{2.5}$ SIP Requirements Rule—is arbitrary. There is substantial evidence of the inclusion of program/staffing costs for control measures wherein the EPA accepted the ADEC's analysis. The most relevant is the EPA's approval in the Final Rule[158] of ADEC's dismissal of the anti-idling restrictions for heavy-duty vehicles, in which staff costs accounted for most of the total costs.[159] In addition to anti-idling restrictions for heavy-duty vehicles, EPA approved ADEC's analysis of several BACM control measures that included an economic analysis where program administration and costs to employ new staff members (categorized into low, medium, and high-cost levels) were included in the cost-effectiveness analysis. Program development costs included in the cost analysis are costs borne by the state and local governments to set up new programs to implement control measures and realize emission reductions. Labor costs included in the cost analysis are costs borne by the state and local governments to hire new staff members as essential operating elements to realize continued emission reductions, and the labor costs were based on 2019 FNSB salaries and benefits which was noted in the cost sheet. Table 10 below lists these measures highlighting those measures that were adopted and included in the control inventory.

Table 10. Summary of Cost-Effectiveness Analysis of Control Measures where Program and Staffing Costs are included as part of Total Costs

BACM Measure #	Measure Name	Admin/Staffing Costs[1]	
		Program	**Labor**
52	Operation and sale of small "pot burners" prohibited	Low	Low
53	No Sale or Exchange of Used Oil for Fuel, unless it Meets Constituent Property Limits	Low	Low

[158] 88 Fed. Reg. at 84649.
[159] Borough staff costs accounted for 57% and capital costs accounted for 43% of the total costs.

60	Anti-Idling for Heavy-duty Vehicles	High	Medium
61	Fuel Oil Boiler Upgrade	High	High
62	Fuel Oil Boiler Upgrade – Replacement	High	High
68[2]	Charbroilers	Med-High	Low – Med
70	Used Oil Burners (Centrifuge)	High	High

[1]Staffing Cost Ranges: Low at $35,407/year, Medium at $70,815/year, and High at $141,629/year. Staffing costs are based on the level of effort combined with labor costs for a Full Time Equivalent (FTE). Program Development Cost (one-time capital cost) Ranges: Low at $50,000, Medium at $100,000/year, and High at $1,000,000. Program costs when annualized over 20 years result in low costs at $4,184/year, medium costs at $8,368/year, and high costs at $83,679/year.
[2] ADEC developed the cost estimates as a range to reflect the variabilities involved in the cost estimates, including equipment type, simple or complicated configuration, age of the restaurant's infrastructure, new restaurants versus retrofitting existing restaurants etc.

In EPA's technical support document for ADEC's control measure analysis, EPA specifically agreed with the economic analysis for Measures 52,[160] 53,[161] 61,[162] and 62,[163] all of which included reasonable program implementation costs with staff salaries. Labor costs were classified as either low, medium, or high in the economic analysis ranging from 0.25 Full Time Equivalents (FTE) to 1 FTE and were clearly labeled as FNSB salaries and benefits with costs derived from the 2019 FNSB Budget breakout. EPA concurred with ADEC's determination that implementing Measures 52 and 53 is economically infeasible based on high cost-effectiveness estimates. EPA's review of the economic analysis for Measure 62 states, "We note that there are greater emission benefits for this measure compared to Measure 61, but also a higher cost of implementation. After reviewing Alaska's economic analysis, we concur that with the economic cost of $6 million per ton of $PM_{2.5}$ removed, this measure is economically infeasible."[164] EPA subsequently approved this economic analysis in the Final Rule.[165] In addition to approving the ADEC's dismissal of anti-idling measures for heavy-duty vehicles (Measure 60) based on an economic infeasibility analysis that included staffing and capital costs, EPA in its Final Rule also approved ADEC's dismissal of Measure 68[166] and Measure 70[167] based on economic infeasibility, likewise including program costs.

Based on the economic analysis for implementing idling restrictions at temperatures of 21°F and above, and the precedent for including reasonable program implementation costs in EPA-approved economic infeasibility analyses, the measure is deemed economically infeasible for implementation in the nonattainment area.

Conclusion

[160] EPA Docket no: EPA-R10-OAR-2022-0115, Document ID: EPA-R10-OAR-2022-0115-0004, at 30.
[161] *Id,* at 30.
[162] *Id,* at 33.
[163] *Id.* at 34.
[164] Technical Support Document: Docket No. EPA-R10-AOAR-2022-0115 (September 27, 2022). Pg. 34.
[165] 88 Fed. Reg. at 84636.
[166] *Id at 84642*
[167] *Id at 84645*

The technological feasibility analysis determined that light-duty idle restrictions can be implemented at schools and commercial establishments. Based on a review of local conditions it was determined that idling restrictions should be imposed at temperatures of 21°F and above for safety concerns. The economic feasibility analysis determined that the implementation of these controls at these temperatures would produce cost-effectiveness estimates that are infeasible. Further, cost-effectiveness assessment of idle restrictions for heavy-duty diesel vehicles found that it was not economically feasible, which EPA approved in the Final Rule. Collectively, anti-idling restrictions are not eligible for consideration as a control measure for the 2024 Revised Amendment to the Serious SIP because they are economically infeasible at this time.

Measure 61: Fuel Oil Boiler Upgrade – Burner Replacement/Repair

Implementing Jurisdiction(s)

- None

Regulation Weblink(s)

- None

Background

EPA commented that the benefits of fuel oil boiler maintenance should be investigated as a control measure.

Analysis

Despite the finding that no benefits for this type of control program have been found in SIPs, information collected for the emissions inventory found that over 60% of the homes in the nonattainment area are heated with fuel oil and most are equipped with fuel oil boilers. Discussions with local vendors and repair technicians were conducted to determine the magnitude of potential fuel consumption benefits from cleaning and replacing burners. It was found that the benefits depend on the age of the boiler and level of regular maintenance.

Brookhaven National Laboratory conducted an extensive evaluation of [168] the effects of maintenance on fuel consumption and emissions of fuel oil boilers and found significant benefits; little information however was found about the benefits of burner replacement. Despite this limitation and the lack of detailed information about the age of fuel oil boilers and related maintenance intervals, it is clear that a program mandating regular maintenance has the potential to reduce fuel use and emissions from fuel oil boilers.

Conclusion

Test measurements have demonstrated that improved fuel oil boiler maintenance reduces fuel consumption and emissions, therefore this measure is technologically feasible. This finding addresses EPA's comments. The results of a cost effectiveness analysis of this measure, presented in Step 4, show this measure is economically infeasible and therefore not eligible for consideration as a 2020 Amendment Plan control measure.

Measure 62: Fuel Oil Boiler Upgrade – Replacement

Implementing Jurisdiction(s)

- None

Regulation Weblink(s)

- None

Background

EPA commented that the benefits fuel oil boiler upgrades should be investigated as a control measure.

Analysis

Despite the finding that no benefits for this type of control program have been found in SIPs, information collected for the emissions inventory found that over 60% of the homes in the nonattainment area are heated with fuel oil and most are equipped with fuel oil boilers. Discussions with local vendors and repair technicians were conducted to determine the magnitude of potential fuel consumption benefits from upgrading/replacing fuel oil boilers. It was found that the benefits depend on the age of the boiler and level of regular maintenance.

Brookhaven National Laboratory conducted an extensive evaluation[169] of emissions from a variety of fuel oil boilers and furnaces (e.g., conventional, condensing, etc.) using fuels of varying sulfur levels and found that technology has a significant benefit. Detailed information about the age and maintenance intervals of the existing stock of fuel oil boilers, however, is required to assess the benefits of a program mandating upgrades/replacement. While this information is not available for homes located in the nonattainment area, the Brookhaven report indicates that newer technologies reduce emissions.

Conclusion

Test measurements have demonstrated that more efficient fuel oil boilers reduce emissions, therefore this measure is technologically feasible. This finding addresses EPA's comments. The results of a cost effectiveness analysis of this measure, presented in Step 4, show this measure is economically infeasible and therefore not eligible for consideration as a 2020 Amendment Plan control measure.

Measure 63: Require Electrostatic Precipitators

Implementing Jurisdiction(s)

- None

Regulation Weblink(s).

- None

Background

ESPs are pollution control devices that use electrical forces to remove fine particulate matter (PM) from exhaust streams. PM collection in an ESP occurs in three steps: suspended particles are given an electrical charge; the charged particles migrate to a collecting electrode; and the collected PM is dislodged or cleaned from the collecting electrode. ESP technology has been available for over a century and successfully employed on numerous industrial applications in the U.S., and throughout the world, with typical PM control efficiencies of 90% – 99%. Central to achieving the aforementioned performance is site specific design, continuous monitoring, and periodic maintenance; i.e. ESPs are not one size fits all and are not plug and play.

Other countries, most notably European countries, have implemented ESPs on residential wood stoves. The technology transfer from the industrial sector to the residential sector required each country to address key issues not inherent in the technology itself; e.g. site-specific design, continuous monitoring, and periodic maintenance. A review of regulations from Zurich, Switzerland, found that ESPs may be retrofitted on handcrafted wood stoves to meet standards in cases where laboratory certification is not practical. Zurich also encourages the use of ESPs in general to reduce emissions, but does not provide any additional regulatory incentive to use an ESP. Notable regulations that address monitoring and maintenance requirements include:

- Annual inspections to verify proper device operation and use of clean dry fuel;
- Annual chimney sweep by certified professional;
- All hydronic heating systems subject to emission measurements every 2 years;
- Only dry and untreated wood may be burned. In case of doubt, an ash sample is collected, analyzed by a laboratory, and judged by the authorities; and,
- Minimum of 60% control efficiency for retrofit control devices, such as ESPs.

No SIPs or EPA guidance documents were identified requiring the installation of an ESP or any retrofit control device on residential wood stoves.

During development of the Serious Area SIP, FNSB and ADEC were engaged in a testing program to evaluate the efficacy of ESPs as a retrofit control device for various solid fuel appliances. The testing program was completed, and reports were made public in July of 2020. The results of the program are discussed below in the Analysis section.

Analysis

A review of applicable SIPs and EPA guidance documents could find no requirements for retrofitting wood stoves with ESPs. While ESPs appear to offer potential emission reductions, there are several obstacles to successful implementation. The lack of a regulatory framework and regulatory authority to certify and guarantee long term performance is one obstacle, specifically:

- The EPA does not have any certification process for retrofit control devices on wood stoves; and,
- The regulatory framework at the local, state, and federal level lack the necessary language to exclude devices with unproven performance (e.g. homemade devices).

No other jurisdiction in the United States has implemented a monitoring and maintenance plan at a residential level that guarantees operation of a retrofit emission control device which create the following obstacles:

- ESPs require professional installation: there are a lack of trained professionals and currently no way to verify installation;
- ESPs require periodic chimney cleanings: currently there is no way to verify cleaning; and,
- ESPs require periodic maintenance: there are a lack of trained professionals and currently no way to verify maintenance.

The implementation strategy, i.e. incentive for residents to purchase and install ESPs, is not clearly identified, which is another obstacle. Community members view ESP installation in lieu of burn bans as the incentive to install; however that strategy could lead to worse air quality conditions if ESP performance deteriorates over time, and there are legal issues regarding backsliding with the Fairbanks Serious Area Plan. Another implementation strategy would be a requirement to install ESPs on certain devices (e.g. devices that are exempt from burn bans), which would achieve the highest air quality benefit but would likely be viewed as regulatory overreach by the community.

Acknowledging the obstacles presented above, community interest remained high in determining whether the addition of an ESP would allow wood-burning to continue when burn bans were in effect, specifically Stage 2 Alerts where only those with a NOASH are allowed to operate solid fuel appliances. To address this interest, FNSB commissioned a testing project to measure the effect of ESPs on PM emitted from an EPA Step 2 certified pellet stove and develop an emission factor suitable for use in a SIP. To provide additional information in support of the FNSB study, ADEC commissioned a small parallel study to measure the effect of ESPs on two EPA Step 2 cordwood appliances: non-catalytic and catalytic.

Brief summaries of the test results are presented in this analysis, however significant insight into the operational performance of the ESP evaluated are contained in the test reports, which are incorporated by reference, but not discussed here. The test reports are available on ADEC's and FNSB's websites at:

http://www.fnsb.us/transportation/Pages/Retrofit-Emission-Control-Device-Testing.aspx

https://dec.alaska.gov/air/anpms/communities/adec-esp-cordwood-test-report/

https://dec.alaska.gov/air/anpms/communities/fnsb-esp-pellet-test-report/

FNSB Step 2 certified pellet stove test summary:
The FNSB-commissioned test program employed two different methods of PM measurement: an EPA filter based method (modified ASTM E2515 protocol), which collects total PM emitted over the entire test and a not yet EPA certified method that uses a tapered element oscillating microbalance (TEOM) that collect time-resolved measurements of PM emitted during the test. The former is the primary measurement method but provides no insight into performance during different phases of operation (startup, high, medium, and low burn). Fueling protocols followed ASTM E2779 which is consistent with EPA certification requirements. The program collected data on PM emitted upstream and downstream from the ESP unit simultaneously to allow a calculation of the efficiency of the unit in reducing emissions. A total of 6 controlled replicate tests were conducted to support development of an emission factor.

Key findings include:

- The overall reduction in PM measured by the primary filter method was 72%; the average TEOM reduction was 47%;
- PM reductions achieved with a pellet stove plus ESP are insufficient to achieve equivalency with fuel oil appliances;
- TEOM measurements found particulate removal varied by phase of operation ranging from 25% during medium burn to 74% during high burn;
- TEOM measurements showed that ESP performance is significantly limited by the occurrence of arcing events, which are caused when the electric field responsible for trapping particles collapses; and,
- Sufficient data was gathered to support development of an emission factor for an ESP equipped Step 2 pellet appliance.

ADEC Step 2 certified catalytic and non-catalytic cordwood appliances test summary:
The ADEC-commissioned test program employed two different methods of PM measurement: an EPA filter-based method (modified ASTM E2515), which collects total PM emitted over the entire test and a not yet EPA certified method that. uses a TEOM that collects time-resolved measurements of PM emitted during the test. The former is the primary measurement method

but provides no insight into performance during different phases of operation (startup, high, medium, and low burn). Fueling protocols followed the Integrated Duty Cycle (IDC), developed by New York State Energy Research & Development Agency (NYSERDA) and Northeast States for Coordinated Air Use Management (NESCAUM). The IDC fueling protocol is not consistent with current EPA certification requirements but provides emission loading representative of real-world conditions. Given the limited scope of the ADEC program, insufficient resources were available to support the collection of simultaneous measurements of PM up and downstream of the ESP unit. Instead, non-simultaneous measurements were collected from baseline (no ESP) and controlled (ESP installed) tests; average differences between the baseline and controlled tests were used to calculate the estimated efficiency in reducing emissions. Three replicate tests were completed for baseline and controlled emissions except for the baseline for the catalytically controlled stove where 2 replicate tests were completed.

Key findings include:

Non-catalytic Cordwood Stove Performance

- The ESP failed due to excessive creosote build-up after 34 hours of operation with dry fuel in a controlled environment. The excessive creosote buildup coupled with an ignition source, such as electrical arcing, is believed to present a potential safety hazard for homeowners;
- It is recommended that the manufacturer update its device design to address the creosote concerns and demonstrate performance using test protocols approved by FNSB, ADEC and/or EPA. It is further recommended that thorough testing on a new design be conducted by the manufacturer on noncatalytic devices of the size used in FNSB prior to further use or testing by FNSB;
- When creosote impacted measurements are ignored, ESP control efficiency was found to range between 66-73% (filter based versus TEOM measurements) for relatively high emitting non-catalyst cordwood stoves. TEOM measurements showed significant variability in ESP control efficiency ranging from 33-92% depending on the test phase of the IDC; and,
- If the creosote concerns can be addressed, ESPs offer significant emission reduction potential for non-catalyst cordwood stoves, which could aid community efforts to improve air quality.

Catalytic Cordwood Stove Performance

- The test results for the ESP equipped catalytic cordwood stove indicate a control efficiency of 1%; and,
- The low emission levels of catalytic cordwood stoves combined with poor ESP performance during the startup test phase and the almost nonexistent reduction in overall emissions suggest that the addition of ESP control for these stoves offers little benefit to the community. However, other variables such as typical number of start-ups influence the overall emission reduction and additional data gathered through simultaneous measurement of PM before and after the ESP could provide additional insight to the efficacy of ESPs on catalytically controlled cordwood appliances.

During the winter of 2019/2020 Golden Valley Electric Association (GVEA) funded an ESP pilot project. The project was funded at $125,000 for two years with a goal of installing 80 ESPs in the nonattainment area over a 2-year period (40 each year). On December 12, 2019 a meeting was held including multiple stakeholders where homeowner agreements, chimney cleaning, and professional installation issues were resolved. Key takeaways include that prior to each ESP being installed the appliance and chimney would be inspected by a licensed chimney sweep to verify that the appliance was installed correctly and that the chimney would be professionally cleaned prior to ESP installation. In a July 21, 2020 FNSB Air Pollution Control Commission (APCC) meeting GVEA provided a report on the community pilot project to install ESPs in the North Pole area. Key takeaways from GVEA's report include:

- 17 ESPs were installed in the North Pole area during January – February 2020;
- Upon inspection after the burn season, nearly half the installed ESPs had failed due to excessive creosote buildup;
- The cause (e.g. wet wood, appliance type, appliance operation, or ESP operation) of excessive creosote buildup was not determined; and
- GVEA stopped project funding on a go-forward basis.

Meeting agenda and audio tracks are available on the FNSB website under the July 21, 2020 Meeting Documents at:
http://www.fnsb.us/Boards/Pages/Air-Pollution-Control-Commission.aspx

By definition a control measure must result in permanent and enforceable emission reductions. A clear implementation strategy has not been identified, therefore for the purposes of this analysis the measure evaluated is: Mandatory installation of an ESP on any appliance that receives a NOASH waiver. These appliances are allowed to operate during the meteorological conditions that lead to the highest ambient PM concentrations, and a quantifiable decrease in emissions during episodic conditions would lead to improved air quality.

Analysis of the FNSB and ADEC test results, combined with the testimony from GVEA, provide a weight of evidence that SFBAs encompass a large range of operational and emission characteristics which have a dramatic effect on ESP performance. As with any post combustion emission control technology, the ESP functions best on appliances with the emission loading and stack effluent characteristics it was designed for with performance decreasing as operational parameters fall outside of design constraints. Due to the large range of appliances within the SFBA source category the control strategy conclusions are divided into the following categories:

- EPA Step 2 Certified Appliances:
  - Pellet stove;
  - Non-catalytic cordwood stove; and,
  - Catalytic cordwood stove.
- All other SFBAs, including but not limited to: hydronic heaters, fireplaces, EPA Step 1 certified appliances, non-certified appliances, fireplace inserts, and any other device that

would qualify for a NOASH under the Emergency Episode Plan in the Serious Area SIP.

Regarding potential safety concerns, it is beyond the scope of this analysis to evaluate the safe use of an ESP or any technology. Potential safety concerns that were identified during analysis are characterized as potential because those concerns are identified but not verified. A complete investigation of product safety was not conducted, therefore a conclusion of "no potential safety issues identified" means none were discovered during analysis and should not be construed as no safety issues exist.

Conclusion

EPA Step 2 certified pellet stove:
FNSB testing shows a quantifiable emission benefit for including an ESP as a control on EPA Step 2 certified pellet stoves. No potential safety issues were identified during analysis. This measure, mandatory installation of an ESP on a pellet stove that receives a NOASH waiver, is technically feasible to implement. The results of a cost effectiveness analysis of this measure, presented in Step 4, show this measure is economically infeasible and therefore not eligible for consideration as a 2020 Amendment Plan control measure.

EPA Step 2 certified non-catalytic cordwood stove:
ADEC testing shows a potential emission benefit for including an ESP as a control on a Step 2 certified non-catalytic cordwood stove, additional testing is required to demonstrate a quantifiable emission benefit. The ADEC testing and GVEA pilot project provide a weight of evidence identifying a potential safety issue due to accelerated creosote buildup. Due to the identification of a potential safety issue this measure, mandatory installation of an ESP on a non-catalytic cordwood stove, is technically infeasible to implement and is dismissed from the control measure analysis.

EPA Step 2 certified catalytic cordwood stove:
ADEC testing shows a limited potential emission benefit (less than 1% emission reduction) for including an ESP as an additional control on a Step 2 certified catalytic cordwood stove, additional testing is required to demonstrate a quantifiable emission benefit. The ADEC testing did not identify a potential safety issue. The GVEA pilot project identified excessive creosote buildup in a catalytic cordwood stove. Due to the identification of a potential safety issue and the limited potential emission benefit this measure, mandatory installation of an ESP on a catalytic cordwood stove is technically infeasible to implement and is dismissed from the control measure analysis.

All other SFBAs:
No additional testing was completed on the other SFBA categories. Due to the potential safety issue of accelerated creosote buildup observed during ADEC testing and the GVEA pilot project, mandatory installation of an ESP on a SFBA is technically infeasible to implement and is dismissed from the control measure analysis.

Measure 64: Weatherization and Energy Efficiency

Implementing Jurisdiction(s)

- **San Joaquin Valley Air Pollution Control District's (SJVAPCD)**
- **Sacramento Metropolitan Air Quality Management District's (SMAQMD)**
- **City of Berkeley**
- **South Coast Air Quality Management District's (SCAQMD)**
- **Texas Commission of Environmental Quality (TCEQ)**

Regulation Weblink(s)

- **https://ww2.valleyair.org/media/h0eliaec/rule-4901.pdf**
- **https://www.airquality.org/ProgramCoordination/Documents/Rule417%20Proposed%20Sep2006.pdf**
- **https://berkeleyca.gov/construction-development/green-building/building-emissions-saving-ordinance-beso/beso-energy**
- **https://www.energy.ca.gov/programs-and-topics/programs/building-energy-efficiency-standards**
- **https://www.aceee.org/files/proceedings/2002/data/papers/SS02_Panel9_Paper04.pdf**

Background

In the 2020 Amendments to the Serious SIP, ADEC reviewed SIPs from other air quality regulatory agencies and did not identify any control measures mandating weatherization and claiming related emission reduction benefits. ADEC identified several programs for improving home heating efficiency in the Nonattainment Area that result in emissions reduction. However, these programs were voluntary programs which do not provide enforceable emissions reduction. To provide enforceable emissions reduction, voluntary programs must be mandated and regulated, which requires significant work and resource commitments.

During the development of the Serious SIP, the Air Quality Stakeholders group identified the possibility of implementing a home energy audit at the time of the home sale, however, the group could not agree on a threshold for energy efficiency or required actions to implement the mechanism. Voluntary measures being implemented indicate that weatherization measures are technologically feasible. However, based on the fact that weatherization measures have not been mandated in other jurisdictions, and significant gaps that exist including applicability, thresholds, requirements, and legal authority to the implementation of these measures, ADEC found the measure to be technologically infeasible and dismissed it from consideration for the 2020 Amendments to the Serious SIP.

EPA rejected ADEC's dismissal of weatherization and energy efficiency programs as a control measure in the 2020 Amendments to the Serious SIP. EPA in their comments[170]

[170] 88 Fed. Reg. at 1454.

stated that ADEC's conclusion that it lacked authority to require insulation was "invalid" and difficulty in quantifying emissions benefits from voluntary programs did not correspond to the requirements of the 2016 $PM_{2.5}$ Final Rule.[171] Finally EPA asserted that a State cannot reject a measure on the basis that another jurisdiction has not adopted and implemented that measure.

After EPA issued its proposed disapproval, ADEC conducted a thorough review of weatherization and energy efficiency programs throughout the continental United States. ADEC also evaluated the existing energy efficiency programs in the Nonattainment Area. Based on this investigation, ADEC in their response to EPA's Partial Disapproval of the Fairbanks Serious SIP and its 2020 Amendments proposed to develop a new regulation consisting of home energy rating at the time of a real estate transaction, along with a commitment to education and outreach. ADEC dismissed adopting any building energy efficiency codes or mandatory weatherization requirements due to limitations on ADEC's legal authority, lack of infrastructure, timing, and resources.

EPA in their Final Rule[172], disapproved ADEC's BACM determination for weatherization until such time as EPA can evaluate the adopted regulation when the State submits a SIP revision. While the EPA appreciated that ADEC did further investigations and proposed to adopt a new regulation, EPA disapproved ADEC's dismissal of implementing building codes and mandatory weatherization measures. EPA stated that the State and local governments are required to have the legal authority, funding, and personnel to meet the CAA requirements.

ADEC, in response to EPA's Final Rule re-evaluated the implementation of building codes and mandatory weatherization measures. Based on is assessment, ADEC's conclusion on dismissing both remains unchanged. ADEC dismissed these measures based on technological infeasibility, and the timeline of implementing these measures to reach attainment.

Analysis

In response to EPA's comments on the 2020 Amendments, ADEC identified weatherization programs in other jurisdictions to fall into three board categories: (1) Public Education and Outreach Programs; (2) Energy Audits/Rating; and (3) Building Energy Codes.

Public education and outreach programs for energy efficiency are implemented as part of San Joaquin Valley Air Pollution Control District's ("SJVAPCD") Rule 4901[173] and Sacramento Metropolitan Air Quality Management District's ("SMAQMD") Rule 417[174].

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[171] 2016 $PM_{2.5}$ Final Implementation Rule. Accessed at https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf.
[172] 88 Fed. Reg. at 84626.
[173] SJVUAPCD, 2018 $PM_{2.5}$ Plan. Accessed at https://www.valleyair.org/pmplans/documents/2018/pm-plan-adopted/2018-Plan-for-the-1997-2006-and-2012-PM2.5-Standards.pdf.
[174] SMAQMD, 2021 PM10 Maintenance Plan, https://www.airquality.org/ProgramCoordination/Documents/PM10%202nd%20Maintenance%20Plan%20-%20Final.pdf.

Rule 4901 targeted at reducing emissions from residential burning, includes a public outreach and education program on best practices for energy efficiency and use. SMAQMD's Rule 417 related to wood-burning devices includes a public awareness component that consists of disseminating weatherization information, in the form of pamphlets, brochures, etc. [175]

Energy audits or rating programs for energy efficiency are implemented in San Francisco, California; Boulder Colorado; Burlington, Vermont; and Ann Arbor, Michigan, and are designed based on the City of Berkeley's Building Energy Saving Ordinance ("BESO"). The City of Berkeley designed the BESO program based on Residential Energy Conservation Ordinances ("RECO") implemented in the 1980s. The BESO program implemented in 2015 overcomes serious challenges in the RECO program by providing homeowners the flexibility to pursue measures voluntarily versus requiring them to implement specific improvements as a result of an energy audit. [176] **These audits are triggered by a sale, transfer, or renovation, and at specified intervals based on a phase-in schedule. The process requires a registered energy assessor to evaluate the building's specific energy and water-saving opportunities in the form of a performance score and/or asset rating.**[177] **As per the 2009 Berkeley Climate Action Plan,**[178] **the average energy savings associated with RECO measures was estimated to be 10-20% per building. Limited examples of building codes implemented for energy efficiency measures include (a) South Coast Air Quality Management District's ("SCAQMD") measure ECC-02, and (b) Dallas-Ft Worth Texas Commission of Environmental Quality ("TCEQ") statewide adoption of the International Residential Code and the International Energy Conservation Code for residential, commercial, and industrial buildings mandated by the 77th Texas Legislature under Senate Bill 5.**

Following a review of energy efficiency programs in other jurisdictions, ADEC performed a deeper investigation of local efforts that were not accounted for in ADEC's SIP submittal to evaluate an emissions reduction commitment in the SIP. Given the high cost of home heating, Alaska has many programs listed below for improving home heating efficiency.

The majority of the energy programs are offered by the Alaska Housing Finance Corporation ("AHFC") which continues to be implemented in the Nonattainment Area since ADEC adopted them as voluntary measures under the moderate SIP.

- **AHFC offers an energy efficiency interest rate reduction ("EEIRR") program, home energy loan program, and weatherization program.**[179]
- **Under the EEIRR program, AHFC offers interest rate reductions when financing new or existing energy-efficient homes or when borrowers make energy**

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[175] SMAQMD, 2021 PM10 Maintenance Plan, https://www.airquality.org/ProgramCoordination/Documents/PM10%202nd%20Maintenance%20Plan%20-%20Final.pdf.

[176] Berkeley Municipal Code § 19.81, Accessed at https://berkeley.municipal.codes/BMC/19.81.

[177] City of Berkeley, Building Energy Saving Ordinance, https://berkeleyca.gov/construction-development/green-building/building-emissions-saving-ordinance-beso/beso-energy.

[178] City of Berkeley, 2019 Climate Action Plan. Accessed athttps://berkeleyca.gov/sites/default/files/2022-01/Berkeley-Climate-Action-Plan.pdf.

[179] Alaska Housing Finance Corporation. Accessed at https://www.ahfc.us/efficiency/energy-programs.

improvements to an existing home. Any property that can be energy rated, and otherwise eligible for Alaska Housing financing may qualify for the program.

- **The AHFC has a home energy rebate program for newly constructed 5-star plus or 6-star homes for all Alaska homeowners with no income limits.[180]**
- **Individuals who meet income limits are eligible to apply for the AHFC's low-income weatherization program implemented by Interior Weatherization, Inc in Fairbanks and North Pole.[181] The program provides low- and moderate-income households with improvements to their homes at no cost to increase energy efficiency. The organization's website states that it has weatherized over 6,000 homes since its inception in 1985.**
- **Interior Weatherization also works with Golden Valley Electric Association to administer the Home $ense Program for Golden Valley customers.[182] This program provides an assessment by a trained energy efficiency specialist of the home and identifies ways to reduce energy usage. In addition, the specialist also provides educational material on best practices in energy efficiency and use.**
- **The AHFC has established Building Energy Efficiency Standards ("BEES") to improve energy efficiency in the construction of new buildings built on or after January 1, 1992, and applying for AHFC financial assistance.[183]**

Programs administered by other entities are listed below:

- **The Heating Assistance Program, administered by the Alaska Department of Health, offsets the cost of home heating for households with income at or below 150% of the federal poverty income guidelines.**
- **The Alaska Energy Authority has a collaborative Energy Efficiency and Conservation education and outreach campaign to increase awareness of ways to improve energy efficiency and conservation in Alaska.[184] A key component of this campaign is the creation of the Alaska Energy Efficiency Partnership stakeholder group that aims to improve the adoption of greater end-use energy efficiency measures and energy conservation behaviors in Alaska through information sharing and integrated planning.**
- **The Southwest Alaska Municipal Conference ("SWAMC"), a regional economic development and regional membership organization provides low-cost energy audits and grant assistance to small businesses and commercial fishers.[185] These audits are funded through the U.S. Department of Agriculture's ("USDA") Renewable Energy Development Assistance ("REDA") grant program to improve the energy efficiency of commercial building infrastructure in areas covering the entire State of Alaska**

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[180] Alaska Housing Finance Corporation, Home Energy Rebate Program. Accessed at https://akrebate.ahfc.us.
[181] Interior Weatherization, Inc. Accessed at http://www.interiorwx.org/index.html.
[182] Golden Valley Electric Association, Home $ense Program. Accessed at https://www.gvea.com/services/programs-services/homeense-audits/.
[183] Alaska Housing Finance Corporation, Building Energy Efficiency Standards. Accessed at https://www.ahfc.us/pros/builders/building-energy-efficiency-standard.
[184] Alaska Energy Authority, Energy Efficiency and Conservation (EE&C) education and outreach campaign. Accessed at https://www.akenergyauthority.org/What-We-Do/Alternative-Energy-and-Energy-Efficiency-Programs/Energy-Efficiency-Conservation/Alaska-Energy-Efficiency-Partnership.
[185] Southwest Alaska Municipal Conference, Energy Audit Program. Accessed at https://swamc.org/programs/energy-audit/.

outside the Municipality of Anchorage. More than 82 commercial fishing vessels and 27 buildings have received or are currently working on energy audits through this program throughout the State of Alaska. Many of these entities who receive the low-cost audit also qualify for a USDA REAP grant that, if awarded, covers 25% of the eligible costs of upgrading a vessel or building.

The implementation of these programs varies depending on the availability of contractors to perform the work, funding levels, and changes in congressional authorizations. All the programs mentioned are voluntary and therefore do not provide enforceable emission reductions.

Based on this investigation, ADEC proposed to develop a new regulation to address the BACM requirements for weatherization. The proposed regulation consists of:

Real estate transaction requirements: Weatherization and energy efficiency proposed regulation.

ADEC proposed to implement a regulation requiring energy efficiency rating for residential buildings at the time of conveyance. The proposed regulation is a new section in the Alaska Administrative Code (AAC), 18 AAC 50.081, and consists of requiring a residential building owner to complete an energy rating with a licensed energy assessor before listing the building or property for sale. This measure will require the owners to pay for the energy rating. The proposed regulation requires the residential building owner to submit the energy rating report to ADEC, and to register any wood-fired heating devices. These elements will aid in the compliance rate for other control measures including the curtailment program and date certain removal of uncertified appliances. Any improvements identified by the energy rater is voluntary. As evidenced in Berkeley, the RECO audit program had serious issues in requiring owners to implement improvements and was subsequently replaced by BECO which provided homeowners with flexibility to implement measures voluntarily. ADEC's energy rating program is designed in a similar way where any improvements identified by the energy rater are voluntary. Energy raters will link the owners to available incentive funding and other voluntary programs by the Alaska Housing Finance Corporation and Alaska Energy Authority.

ADEC's review highlights several voluntary energy efficiency programs around the State with overlapping goals, implemented by different agencies according to different authorities, and funded by dissimilar grant systems. ADEC currently has several other public education programs providing information on burn curtailments, wood stove operations, dry wood, wildfire, and smoke management. Similar to SJVAPCD, ADEC commits to a robust advertising and education program including best practices to improve efficiency in an arctic environment and available economic and practical mechanisms that can assist homeowners in improving both efficiency and regulatory compliance.

ADEC dismissed implementing building energy efficiency codes or mandatory weatherization requirements for several reasons. As of the date of the ADEC's response to

EPA's comments[186], neither the State nor the Borough has the authority to enact or enforce a building code measure that overlaps the authority of the City. The City is a home rule municipality that has exclusive authority to enforce a specific building code[187] and the City has, indeed, enacted several discrete code provisions that could authorize certain weatherization measures.[188] Because the City is a home rule entity with certain constitutional powers, the State would have to enact a statute to preempt the City's building code authority before ADEC could issue a regulations package requiring additional or new insulation. [189] Furthermore, although the Borough may have the authority to provide for air pollution control by virtue of AS 29.35.210 and AS 46.14.400 outside Fairbanks City limits, the Borough cannot implement that authority which includes the authority to enact and enforce a building code.[190]

The State does appear to have some authority to adopt and enact weatherization measures such as additional or new insulation pursuant to AS 46.03.020 (10) and AS 46.14.030 within the Borough.[191] However, the practical implications of ADEC implementing building codes are significant. First, ADEC does not have the subject matter expertise or staff required to provide the technical information required to implement and enforce a new insulation or energy-efficient measure. Second, there is a lack of local infrastructure in terms of the availability of energy auditors, and training resources (in terms of training for new auditors and updating existing auditors to keep up with code updates) to perform the home inspections to ensure compliance with building codes. Based on ADEC's research, there are two types of energy assessors: (1) energy raters; and (2) energy auditors. Energy raters assess only residential buildings and do not require certification but must undergo training from the Alaska Housing Finance Corporation (AHFC). On the other hand, energy auditors can assess both residential and commercial buildings and require a certification either as a certified energy manager or certified energy auditor.[192] Unlike the AHFC low-income program which requires energy raters for assessment, the SWAMC requires energy auditors for its program. Based on a conversation with the SWAMC[193], there is only one full-time auditor and two part-time auditors available for performing home inspections throughout the State. While the proposed regulation on energy rating program requires energy raters, energy auditors are required for building code compliance. Implementing mandatory weatherization programs such as building codes in addition to energy ratings would put an additional burden on the existing local infrastructure which is already strained. This could lead to significant delays or even failure of the program.

[186] March 22, 2023.
[187] AS 29.04.010; *see also* Alaska Const. art. X, §11.
[188] City of Fairbanks Municipal Code Library, https://library.municode.com/ak/fairbanks/codes/code_of_ordinances.
[189] AS 29.10.200 ("Only the following provisions of this title apply to home rule municipalities as prohibitions on acting otherwise than as provided.").
[190] Energy Efficiency Work Group. 2018 Meeting Summary. Accessed at
[191] Vol. II: III.D.7.8 at 65. Accessed at https://dec.alaska.gov/media/22030/iii-d-7-08-modeling-adopted-11-18-20.pdf
[192] Conversation between Jim Fowler from Energy Audits of Alaska and Robert Dulla, Trinity Consultants, on behalf of ADEC.
[193] Conversation between Lizzi Makovec, Southwest Alaska Municipal Conference (SWAMC) Energy Audit Coordinator, and Suriya Vallamsundar, Trinity Consultants, on behalf of ADEC (Dated 02/08/2023).

Based on these factors, ADEC dismissed adopting building codes or any new weatherization measures. ADEC concluded that expanding the current public education and outreach program to include information on energy efficiency and implementing a regulation requiring residential building owners to perform an energy rating addresses the deficiencies cited by EPA and meets the BACM requirements.

EPA in their Final Rule[194], disagreed with ADEC's dismissal of mandatory weatherization measures such as implementing building codes in the Nonattainment area. The EPA appreciated that the State did further investigation and analysis of the types of measures that, if adopted, might meet BACM. While the EPA acknowledged the various voluntary programs in place for energy efficiency, these measures, however, do not appear to meet the EPA guidelines for enforceability and SIP emission reduction credit.

In response to ADEC's responses on the technological infeasibility of implementing mandatory weatherization programs (e.g., building codes), EPA noted that a State is required to have the legal authority, funding, and resources under the State law to meet the CAA requirements. A state may under state law elect to share its authority and responsibility for meeting CAA requirements with local governments. Having done so, however, it is not appropriate for a state to claim that it cannot meet a CAA requirement due to this division of authority and responsibility. While EPA acknowledged that certain home rule cities and borough may have exclusive legislative powers under the Constitution of the State of Alaska, including building codes, EPA noted that this does not mean that no State or local government has authority to enact weatherization or energy efficiency measures, but merely means that the home rule city or borough must do so. EPA will review ADEC's revised energy efficiency and weatherization measures once ADEC formally submits them to the EPA as part of a SIP revision.

ADEC again reealuated the complex layers of authority to enact, implement, and enforce building codes in the nonattainment area. While the EPA is correct that the State *in totum* does have existing authorities or could enact new authorities to implement a weatherization measure, the existing authorities would need to be statutorily amended to apply to different agencies, cities, or boroughs. If any new authorities were created by the legislature for the various government entities, those authorities would need to be coextensive. That process of developing new authorities is complex and would significantly impact the timeline to attainment.

ADEC evaluated the earliest date that building codes could be implemented which was not discussed in ADEC's responses to EPA's partial disapproval of the SIP. The timeline to implement a control measure is one of the steps outlined in the $PM_{2.5}$ Implementation Rule[195]. Step 5 in the BACM process states that the timeline to implement a control measure is one of the criteria to assess the feasibility of the measure – which is. no later than 4 years after the effective date of reclassification to a serious nonattainment area. Accordingly, BACM was required to be adopted and implemented before the Serious area

[194] 88 Fed. Reg. at 84626.
[195] 2016 PM2.5 Final Implementation Rule. Accessed at https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf

attainment date of December 31, 2019. After the Fairbanks $PM_{2.5}$ Nonattainment Area failed to attain by December 31, 2019, ADEC was required to adopt the BACM by December 31, 2020.[196] Based on EPA's Final Rule[197] and the regulatory references included for BACM (40 CFR 51.1010 (C)(3)[198], 51.1004(a)(3)[199]), following the finding of failure to attain by the applicable Serious area attainment date, the state may make a demonstration that a measure identified is not technologically or economically feasible to implement in whole or in part within 5 years or such longer period as the EPA may determine is appropriate after the EPA's determination that the area failed to attain by the serious area attainment date or December 31, 2024.

ADEC reviewed the process of implementing building codes in other jurisdictions. The process essentially consists of three steps[200] wherein at step 1 building codes and standards developed by independent entities such as the International Code Council (ICC) for residential and American Society of Heating, Refrigerating and Air Conditioning Engineers (ASHRAE) for commercial are adopted by municipalities and states. [201] These codes and standards are updated every three years by various committees comprised of technical researchers, code officials, developers, builders, designers, and others and are analyzed by the Department of Energy. In step 2, the process of adoption by states and local entities happens through legislative action or by regulatory agencies authorized by a legislative body. The process involves stakeholder and public involvement, addressing comments, and getting their buy-in with the final version of the code. Once adopted, the code becomes law within a particular state or local jurisdiction. Step 3 consists of code enforcement and compliance. Code compliance is the most important component to ensure optimal energy efficiency, resiliency, and health benefits.[202] Regardless of how energy codes are adopted (state or local level), the local jurisdictions are responsible for implementing the codes and establishing a code inspection and verification program. This, in turn, translates to legal obligations for design professionals and builders who design and construct buildings as per the latest codes, and local code officials who inspect and ensure compliance with the codes. [203] Educational support for builders, code officials, and others working in construction and related industries is necessary to increase understanding and requirements of the energy code, especially when a new code is adopted. Therefore,

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[196] ADEC, 2020 Amendments to the Serious SIP. Appendix III.D.7.7. Assessed at https://dec.alaska.gov/media/22038/appendix-iii-d77-control-strategies-adopted-11-18-20.pdf.
[197] 88 Fed. Reg. at 84626
[198] 40 CFR 51.1010 (C)(3). Accessed at https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-51/subpart-Z/section-51.1010
[199] 51.1004(a)(3). Accessed at https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-51/subpart-Z/section-51.1004#p-51.1004(a)(3).
[200] Midwest Energy Efficiency Alliance. Energy Codes Development, Adoption and Compliance. Accessed at https://www.mwalliance.org/blog/energy-code-development-adoption-and-compliance-benefits-regularly-updated-codes.
[201] Office of Energy Efficiency and Renewable Energy. Building Codes. Accessed at https://www.energy.gov/eere/buildings/articles/how-are-building-energy-codes-developed.
[202] Office of Energy Efficiency and Renewable Energy. Building Energy Codes - Development, Adoption, Implementation, and Compliance. Accessed at https://www.energycodes.gov/codes-101/develop-adopt-implement-comply.
[203] Office of Energy Efficiency and Renewable Energy. Building Energy Code Compliance. Accessed at https://www.energy.gov/eere/buildings/articles/building-energy-code-compliance.

training resources and technical assistance provided by municipalities and states, are crucial.

An overview of these steps shows that the process of implementing building codes is time-consuming. For example, a timeline published by Massachusetts for updating their building code in 2023 shows a timeline of 2 years.[204] California Energy Commission (CEC) recently published their timeline to adopt the latest 2025 Building Energy Efficiency Standards.[205] Their update process consists of three stages; data gathering and analysis during the pre-rulemaking stage, addressing stakeholder and public comments, and adopting the code during the rulemaking stage, and updating the compliance manuals, compliance software during the post-adoption stage. CEC estimated the timeline for the pre-rulemaking and rulemaking stages to span from March 2022 through January 2026.

The timelines from other states cited correspond to updating an energy code that has been in place since 1976 for California[206] and 2009 in Massachusetts.[207] These timelines would be compounded for the first-time implementation of building codes and considering local conditions in Fairbanks and the time required for outreach to stakeholders, public review, implementing a regulation, establishing a system and resources for code enforcement, and compliance, etc. Based on a conversation with the International Code Council[208], a typical timeline for first-time implementation of energy codes would range between 24- 36 months for the lower-48 states and would be much longer for Alaska. As noted by ICC, a key barrier for Alaska is the fragmentation of the state where there are stretches of land not under any regulatory authority, and this makes the administration and adoption of codes much different from the lower-48 states. Based on this evidence, a reasonable estimate of 3 years to implementation of a novel weatherization program in a building code would likely place implementation beyond not only the statutory requirement for the implementation of BACM by December 31, 2024, but also beyond the 2027 attainment date identified in the 2024 SIP Amendments.

Based on a combination of these factors, ADEC dismissal of building codes based on technological infeasibility remains unchanged. In addition to technological infeasibility, ADEC dismissed building codes as the earliest date the measure can be implemented

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204 https://www.cambridgeseven.com/about/news/what-to-expect-from-the-massachusetts-energy-code-in-2023/

205 California Energy Commission. 2025 Building Energy Efficiency Standards. Accessed at https://www.energy.ca.gov/programs-and-topics/programs/building-energy-efficiency-standards/2025-building-energy-efficiency.

206 California Energy Commission. Building Energy Standards. Accessed at https://www.energy.ca.gov/publications/2015/building-energy-efficiency-standards-residential-and-nonresidential-buildings#:~:text=The%20Building%20Energy%20Efficiency%20Standards,then%20as%20directed%20by%20statute.

207 Massachusetts Building Energy Code. Accessed at https://www.mass.gov/info-details/building-energy-code#:~:text=In%202009%2C%20Massachusetts%20became%20the,%2Dthe%20%22Stretch%20Code%22.

208 Conversation with Kraig Stevenson, Senior Regional Manager (AK, HI, ID, MT, OR, WA) at International Code Council. (https://www.iccsafe.org/) by Suriya Vallamsundar, Trinity Consultants, on behalf of ADEC. Date April 29, 2024.

exceeded the regulatory timeline to achieve the expeditious attainment of the ambient $PM_{2.5}$ standard.

Conclusion

In addition to the currently ongoing several voluntary programs, ADEC has adopted a new regulation on weatherization. Firstly, ADEC commits to expanding the current public education and outreach program to include information on weatherization and energy efficiency. Secondly, the regulation requires residential building owners to perform an energy rating prior to listing the home for sale. The adoption of the regulation is sufficient to meet the BACM requirements of this measure.

Measure 67: Coffee Roasters

Implementing Jurisdiction(s)

- **Vermont Air Quality and Climate Division (VAQCD)**
- **Colorado Department of Public Health and Environment (CDPHE)**
- **Puget Sound Clean Air Agency (PSCAA)**
- **Southwest Clean Air Agency (SWCAA)**
- **San Diego Air Pollution Control District (SDAPCD)**
- **Oregon Department of Environmental Quality (ODEQ)**
- **South Coast Air Quality Management District (SCAQMD)**
- **Bay Area Air Quality Management District (BAAQMD)**

Regulation Weblink(s)

- **https://dec.vermont.gov/air-quality/permits/source-categories/coffee-roasters**
- **https://www.colorado.gov/pacific/sites/default/files/AP_Coffee-Roasting.pdf**
- **https://pscleanair.gov/DocumentCenter/View/4633/Coffee-Roaster-GO-Draft.**
- **https://www.swcleanair.gov/docs/regs/reg400.pdf.**
- **https://www.sdapcd.org/content/sdapcd/permits/equipment-types/coffee-roasters.html**
- **https://www.sdapcd.org/content/dam/sdapcd/documents/permits/APCD-bact.pdf.**
- **https://www.oregon.gov/deq/FilterPermitsDocs/AQGP-016.pdf.**
- **http://www.aqmd.gov/docs/default-source/rule-book/reg-ii/rule-219.pdf?sfvrsn=4**
- **https://www.baaqmd.gov/~/media/dotgov/files/rules/reg-2-permits/2021-amendments/documents/20211215_rg0201-pdf.pdf?la=en&rev=103cc60e706947d3ad1e4f5a090483c1.**

Background

ADEC regulation 18 AAC 50.055[209] imposes emission limits on industrial processes and fuel-burning equipment that are applicable to coffee roasting operations in the Fairbanks North Star Borough. This regulation limits the opacity of visible emissions from fuel-burning equipment to no more 20 percent averaged over any six consecutive minutes.[210] Prior to 2019, neither ADEC nor the Borough have adopted regulations specific to emissions from coffee roasting operations.

In the 2020 Amendments to the Serious SIP, ADEC reviewed regulations governing coffee roasting facilities. In the review, ADEC identified several jurisdictions to have permit requirements for facilities from which emissions exceed a specific threshold, and coffee roasting facilities are not exempted from these requirements. Among all jurisdictions, ADEC found the permit requirement of the San Diego County Air Pollution Control District requiring the use of a cyclone in combination with an afterburner or wet scrubber that results in visible emissions that are substantially less than 20% opacity to constitute the most stringent emission control requirement for coffee roasting operations.

ADEC adopted a new regulation[211], 18 AAC 50.078(d), effective January 8, 2020, that requires coffee roasters within an area identified in 18 AAC 50.015(b)(3) to install a pollution control device on any unit that emits 24 lbs or more of particulate matter within a 12-month period from the effective date of the regulation. ADEC noted that it may waive this requirements if the facility provides information demonstrating that control technology is technically or economically infeasible. A spreadsheet[212] is available for sources to provide the information required to assist in calculating the estimated air emissions for coffee roaster(s) based on the specifics of each roaster and how much coffee is roasted each year.

After ADEC adopted this regulation, ADEC required coffee roasters above the emission threshold to submit information regarding their businesses and operations. ADEC sent two sets of letters on December 19, 2019, and March 4, 2020, respectively, to four coffee roasters in the Nonattainment Area to notify the businesses about the new regulation. ADEC found that one North Pole coffee roaster had already installed control technology. The finding that a thermal oxidizer is currently used to control emissions from a facility located within the Nonattainment Area demonstrated that this measure is technologically feasible. However, as ADEC adopted the new regulation that met the BACM requirement in an alternate form, ADEC dismissed the measure for consideration as a 2020 Amendment Plan control measure.

EPA in their comments on 2020 Amendments rejected ADEC's dismissal of measure 67 and stated that regulation 18 AAC 50.078(d), is not adequately specific or bounded and

209 https://dec.alaska.gov/media/1038/18-aac-50.pdf.
210 *Id.*
211 *Id.*
212 ADEC. Small Source Information & Requirements - Fairbanks North Star Borough PM2.5 Nonattainment Area. Accessed at http://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-small-source-information-requirements/.

lacked enforceability.[213] EPA stated that the rule does not require the use of emissions controls once installed, specify any emission limits, nor monitoring requirements with which the subject sources must comply. In addition, the rule contains a waiver provision based on the facility providing information demonstrating that the control technology is technologically or economically infeasible. Finally, the State must adopt permanent and enforceable control measures for this source category even if certain sources within the source category have existing controls.

In response to EPA's comments,[214]ADEC re-reviewed coffee roaster regulations in other jurisdictions and proposed to develop a new regulation replacing 18 AAC 50.078(d), to address the gaps noted by EPA specifically related to enforceability, specifying emission limit for control devices, and waiver provision based on infeasibility. The regulation is structured as a 'permit-by-rule' which will contain substantive requirements that apply to coffee roasters over the 24 pounds per year emission threshold.

EPA in their Final Rule[215], proposed to disapprove ADEC's BACM determination for coffee roasters until the EPA evaluates the revised regulation when the State submits it to the EPA as a SIP revision.

Analysis

Since the 2020 Amendments, ADEC updated the review of permitting requirements in other jurisdictions that are either based on the amount of coffee beans roasted or emissions produced. These requirements vary dramatically from region to region, with some regions imposing permit restrictions along with control technology requirements (*e.g.* Vermont, Puget Clean Air Agency), while some regions have no regulations (*e.g.* Utah).

- **Vermont Air Quality and Climate Division (VAQCD): In Vermont, an Air Permit is not required for coffee operations roasting less than 1 million pounds of green beans annually, although requirements for emission controls may still apply.[216] VAQCD requires all production-scale roasters to be equipped with emission controls such as a catalytic or thermal oxidizer to control odors and visible emissions from the roasting operation, and precautions to minimize or control dust from the handling of green and roasted beans. There may be some exceptions for small roasting operations (which typically have a capacity of less than 5 pounds per batch) to have uncontrolled coffee roasting.**

- **Colorado Department of Public Health and Environment (CDPHE): The Air Pollution Control Division at the Colorado Department of Public Health and Environment (CDPHE) administers and enforces the regulations governing coffee roasters. The CDPHE has a procedure for filing Air Pollutant Emission Notices (APENs) and**

[213] 88 Fed. Reg. at 58010.
[214] *Id.*
[215] 88 Fed. Reg. 84626.
[216] Vermont Department of Environmental Conservation, "Coffee Roasters," available at https://dec.vermont.gov/air-quality/permits/source-categories/coffee-roasters.

permits.[217] In attainment and maintenance areas for $PM_{2.5}$, CDPHE requires coffee roasters that emit more than 2 tons per year of $PM_{2.5}$ to obtain an air permit. [218] Permit requirements may include a 20% opacity limit on visual emissions, as well as a cyclone or afterburner to control emissions. These requirements do not apply to all coffee roaster permits.[219] The CDPHE conducts routine inspections for compliance and imposes corrective actions in cases of noncompliance.[220]

- **Puget Sound Clean Air Agency (PSCAA), Washington: PSCAA regulations require each coffee roaster to register as per PSCAA Regulation I, Section 5.05. Some large coffee roasting operations may need to report annual emissions under Agency Regulation I, Section 5.05(b) depending on the facility-wide actual emissions that exceed 25 tons/year for PM, VOC, CO, NOx, and SO_2. PSCAA also created a General Order of Approval[221] for 5–12 kilogram per batch coffee roasting operations, which functions as a general permit. The General Order requires installation of a thermal or catalytic oxidizer and recordkeeping.**

- **Southwest Clean Air Agency (SWCAA), Washington: Under SWCAA's regulations for air pollution sources,[222] batch coffee roasters with a capacity of 10 pounds or greater of green coffee beans per batch must install and operate an afterburner (i.e. thermal oxidizer). For batch configuration coffee roasters with a capacity of less than 100 pounds of green coffee beans per batch, visible emissions must not exceed five percent opacity for more than three minutes in any one hour. In addition, such coffee roasters must be equipped with an afterburner, and have recordkeeping and reporting requirements.**

- **San Diego Air Pollution Control District (SDAPCD): SDAPCD requires a permit for any coffee roaster with a maximum capacity above 11 pounds (5 kg). The guidance does not specifically require control technology, but rather states that emissions from coffee roasting are typically controlled using a combination of a cyclone and either thermal oxidizer or wet scrubber.[223] If a piece of equipment or process emits more than 10 pounds per day of PM_{10}, NOx, VOCs, or SOx, then the application must include a**

[217] Colorado Department of Public Health and Environment (CDPHE), Air Pollution Emissions Notice (APEN). Accessed at https://cdphe.colorado.gov/apens-and-air-permits/do-you-need-an-apen-or-air-permit.
[218] Colorado Department of Public Health and Environment, "APEN and permit threshold table," available at https://cdphe.colorado.gov/apens-and-air-permits/apen-and-permit-threshold-table (indicating for $PM_{2.5}$ that Colorado does not have an existing nonattainment area for this pollutant and utilization of the attainment area thresholds is appropriate).
[219] Telephone communication with Jonathan Brickey, Construction Permitting Unit II Supervisor, CDPHE Air Pollution Control Division (March 15, 2022).
[220] Colorado Small Business Assistance Program, An Overview of Colorado Air Regulations for: Coffee Roasting (October 2022), available at https://cdphe.colorado.gov/apen-and-permitting-guidance-from-sbap.
[221] Puget Sound Clean Air Agency, "General Order of Approval," available at https://pscleanair.gov/DocumentCenter/View/4633/Coffee-Roaster-GO-Draft.
[222] Southwest Clean Air Agency, General Regulations for Air Pollution Sources (February 11, 2023), available at https://www.swcleanair.gov/docs/regs/reg400.pdf.
[223] San Diego Air Pollution Control District. Coffee Roasters. Accessed at https://www.sdapcd.org/content/sdapcd/permits/equipment-types/coffee-roasters.html

BACT analysis. For PM, the BACT control option is natural gas with cyclone and afterburner.[224]

- **Oregon Department of Environmental Quality (ODEQ): ODEQ administers a general permit applicable to coffee roasters that roast 30 or more green tons per year.**[225] **Such roasters must have a pollution control device installed and operational, which may be a direct-flame afterburner (i.e. thermal oxidizer) or catalytic converter. Visible emissions must not equal or exceed 20% opacity. The permittee must not allow plant site emissions to exceed 9 tons per year of $PM_{2.5}$. The permittee must monitor and maintain records.**

- **Utah: Utah has no rule governing coffee roaster emissions and does not require the installation of any control technology. The Utah Department of Environmental Air Quality assists with funding through the Utah Clean Air Partnership Program (UCAIR) for businesses to install control technology to reduce emissions.**[226]

- **South Coast Air Quality Management District (SCAQMD, California): SCAQMD's rules 201 and 203 require a permit to both construct and operate a coffee roaster.**[227] **Per Rule 219, a coffee roaster is permit-exempt if its maximum capacity is 15 kilograms or less per batch.**

- **Bay Area Air Quality Management District (BAAQMD), California: AQMD rules 2-1-301 and 302 require a permit to construct and operate facilities, which include coffee roasters.**[228] **Similar to the South Coast, BAAQM exempts from these requirements coffee roasters with a capacity of less than 15 pounds of beans per hour, and any stoners or coolers operated in conjunction with such roasters.**

Following the review of requirements in other air quality regulatory agencies, and in response to EPA's concerns, ADEC is repealing and readopting regulation 18 AAC 50.078. This regulation applies to any coffee roasting unit in the Nonattainment Area that emits 24 pounds or more of particulate matter in 12 months. The emission threshold was approved by the EPA.[229] **Coffee roasters that emit more than 24lb/yr of PM emissions are required to use a pollution control device, such as a catalytic or thermal oxidizer, or other control**

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224 San Diego County Air Pollution Control District, New Source Review Requirements for Best Available Control Technology (BACT) Guidance Document (June 2011), at 3-8 (PDF page 30), available at https://www.sdapcd.org/content/dam/sdapcd/documents/permits/APCD-bact.pdf.
225 Oregon Department of Environmental Quality, Air Contaminant Discharge Permit, at 1, available at https://www.oregon.gov/deq/FilterPermitsDocs/AQGP-016.pdf.
226 Utah Clean Air Partnership Program, available at https://www.ucair.org/; *see also* Bailey Toolson, "Air Assist Helps Millcreek Coffee Roasters Reduce Emissions with Every Cup," Utah Department of Environmental Quality, Air Quality (October 22, 2021), available at https://deq.utah.gov/air-quality/air-assist-millcreek-coffee-roasters-reduce-emissions.
227 South Coast Air Quality Management District, Permit Rules, Accessed at http://www.aqmd.gov/docs/default-source/rule-book/reg-ii/rule-219.pdf?sfvrsn=4
228 Bay Area Air Quality Management District, Regulation 2: Permits (December 15, 2021), available at https://www.baaqmd.gov/~/media/dotgov/files/rules/reg-2-permits/2021-amendments/documents/20211215_rg0201-pdf.pdf?la=en&rev=103cc60e706947d3ad1e4f5a090483c1.
229 88 Fed. Reg. at 1480. Technical Support Document: Docket No. EPA-R10-AOAR-2022-0115.

devices with an equivalent emissions control efficiency. Once controls have been installed, the coffee roasting units are subject to an emission control limit of 0.12 lbs per ton of coffee roasted. This limit is based on AP-42's emission factors for coffee roasting operations with a thermal oxidizer.[230] The regulation limits the opacity of visible emissions from coffee roasters to no more than 10 percent averaged over any six consecutive minutes. The revised opacity limits strengthen the limits that the coffee roasters were subjected to via 18 AAC 50.055. Furthermore, regulation requires the coffee roasting units to monitor and maintain records related to the operation, maintenance of the units, and performance of the control devices and submit an annual report. The regulation does not have a waiver provision exempting facilities that demonstrate technological or economic infeasibility.

Conclusion

ADEC's new regulation, in the form of a permit-by-rule, addresses EPA's concerns regarding enforceability, specifying an emission limit for control devices and the waiver provision based on infeasibility. The adoption of the regulation is sufficient to meet the BACM requirements of this measure, and no additional analysis is required.

Measure 68: Charbroilers

Implementing Jurisdiction(s)

- **Bay Area Air Quality Management District (California)**
- **South Coast Air Quality Management District (California)**
- **San Joaquin Valley Unified Air Pollution Control District (California)**
- **Utah Department of Environmental Quality (UDAQ)**
- **New York City Department of Environmental Protection (NYCDEP)**

Regulation Weblink(s)

- **http://www.baaqmd.gov/~/media/dotgov/files/rules/reg-6-rule-2-commercial-cooking-equipment/documents/rg0602.pdf?la=en;**
- **http://www.aqmd.gov/docs/default-source/rule-book/reg-xi/rule-1138.pdf?sfvrsn=4,**
- **http://www.valleyair.org/rules/currntrules/r4692.pdf**
- **https://rules.utah.gov/publicat/code/r307/r307-303.htm.**
- **https://codelibrary.amlegal.com/codes/newyorkcity/latest/NYCadmin/0-0-0-42985.**

Background

ADEC's regulation 18 AAC 50.055[231] imposes emission limits on industrial processes and fuel-burning equipment that are apply to charbroiling operations in the Nonattainment

[230] AP-42. Table 9.13.2-1. Accessed at https://www.epa.gov/sites/production/files/2020-10/documents/c9s13-2.pdf.
[231] https://dec.alaska.gov/media/1038/18-aac-50.pdf.

Area. This regulation limits the opacity of visible emissions from fuel-burning equipment to no more than 20 percent averaged over any six consecutive minutes. Although, ADEC nor the Borough have adopted regulations specific to emissions from charbroiling operations, regulation 18 AAC 50.055 serves as a BACM control measure for charbroilers in the Nonattainment Area.

In the 2020 Amendments to the Serious SIP, ADEC reviewed the existing emission control requirements from other air quality regulatory agencies to reduce $PM_{2.5}$ emissions from charbroiler operations. Based on the review of air quality regulations, ADEC found installing a control device to reduce emissions from charbroilers to be technologically feasible. As part of the BACM process, ADEC followed the technological feasibility analysis by conducting an economic analysis related to installing a catalytic oxidizer on charbroilers in the Nonattainment Area. ADEC found that installing a catalyst oxidizer on charbroilers is not cost-effective, and therefore dismissed it for consideration as a 2020 Amendment Plan control measure.

EPA in their comments[232] on the 2020 Amendments, stated that while ADEC's economic analysis was reasonable, ADEC did not evaluate other available control measures, and did not explain whether chain-driven or underfired charbroilers are present in the Nonattainment Area.

Following EPA's proposal, ADEC performed a deeper investigation by reaching out to local agencies to determine the types of charbroilers present in the Nonattainment Area and evaluated the information obtained as part of regulation 18 AAC 50.055 that was not accounted for in ADEC's prior SIP submittal on control measures. ADEC also conducted a thorough review of available charbroiler regulations and control technologies from other air quality agencies around the country. Based on the information, ADEC conducted a technological and economic analysis of different control technologies for the underfired charbroilers present in the Nonattainment Area.

EPA in their Final Rule[233] found ADEC's analysis to fill the analytical gaps noted in EPA's Proposal. EPA found the ADEC's economic analysis acceptable for the different control technologies for underfired charbroilers and accepted the ADEC's findings that installing charbroiler emission controls is economically infeasible at this time. EPA also accepted that the visible emission limit in 18 AAC 50.055 constituted BACM for the charbroiler source category.

Analysis

[232] 88 Fed. Reg. at 1480.
[233] 88 Fed. Reg. at 84626.

Charbroiling consists of cooking products, generally meat, at a high temperature in commercial establishments like restaurants and large-scale cooking operations.[234] Underfired charbroilers have a heating source, a high-temperature radiant surface, and a slotted grill that holds the meat or other food while exposing it to radiant heat. Chain-driven charbroilers have conveyor belts to carry the meat through the flame area, where the flames broil the meat on the top and bottom simultaneously. For underfired charbroilers, PM and VOC emissions occur when grease from the meat falls onto the radiant surface. Compared to chain-driven charbroilers, underfired charbroilers produce four times the emissions when cooking equivalent amounts of products. The most widely used control technology for a chain-driven charbroiler is a catalytic oxidizer due to their reduced costs compared to other technologies. But this technology is not recommended for underfired charbroilers, because the exhaust from these devices loses too much heat as it is directed to the control device, and the reactions at the catalyst cannot take place at this lower temperature [235,236] For underfired charbroilers, the most widely cited control technologies are electrostatic precipitators ("ESP"), high-efficiency particulate arresting ("HEPA") filtration systems, and wet scrubbers.[237,238]

ADEC evaluated the type of charbroilers present in the Nonattainment Area based on information gathered as part of regulation 18 AAC 50.078(c), and a survey of local authorities. ADEC adopted a new regulation 18 AAC 50.078(c), effective January 8, 2020, that required small area sources of $PM_{2.5}$, including commercial charbroilers, to provide one-time information on their operations by March 15, 2020, or 60 days after commencing operations. This information consisted of the location, operation type (chain driven versus underfired), number of operations, fuel used, # of lbs of meat cooked/week, etc. On January 28, 2020, ADEC sent 187 letters to restaurants that were possible commercial charbroiler operators in the Nonattainment Area. ADEC received responses from 56 out of the 187 restaurants, 13 of which reported that a charbroiling device was present in their establishment. All 13 reported devices were underfired charbroilers.

Due to the lower response rate, ADEC queried its Environmental Health Division (which includes food safety regulators), the State Fire Marshals, and third-party inspectors. None were aware of any chain-driven charbroilers operating in the Nonattainment Area. Thus, based on the information gathered under the regulation and the survey, as well as by querying local authorities, ADEC updated its analysis to pertain to underfired charbroilers

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[234] Jill Whynot, Gary Quinn, Pamela Perryman & Peter Votlucka, Control of Fine Particulate ($PM_{2.5}$) Emissions from Restaurant Operations, 49 Journal of the Air & Waste Management Association 95-99 (1999).
[235] SJVUAPCD, Revised Proposed Amendments to Rule 4692 (Commercial Charbroiling) August 20, 2009. Accessed at http://www.valleyair.org/workshops/postings/2009/09-17-09/4692/R4692_staffreport_PH2.pdf.
[236] Yang S, Subramanian S, Singleton D, Schroeder C, Schroeder W, Gundersen MA, Cronin SB. First results on transient plasma-based remediation of nanoscale particulate matter in restaurant smoke emissions. Environmental Research 2019,178:108635.
[237] SJVUAPCD, 2017 District Staff Report. Accessed at http://www.valleyair.org/Board_meetings/GB/agenda_minutes/Agenda/2017/September/final/10.pdf; SJVUAPCD, 2020 District Staff Report. Accessed at https://www.valleyair.org/Board_meetings/GB/agenda_minutes/Agenda/2020/December/final/11.pdf.
[238] SCAQMD, 2009. Accessed at http://www.aqmd.gov/docs/default-source/rule-book/support-documents/rule-1138/par1138pdsr.pdf.

only.[239] Additionally, ADEC expanded its review of regulations adopted by other air quality regulatory agencies from the 2020 Amendments by focusing on regulations in place for underfired charbroiling emissions. Their review included several districts in California and agencies in other states (e.g., Utah, New York).

The Bay Area Air Quality Management District (BAAQMD) adopted Regulation 6, Rule 2 (Commercial Cooking Equipment) in 2007 to reduce PM emissions from both chain-driven and under-fire charbroiling sources.[240] The regulation requires a catalytic oxidizer for chain-driven charbroilers with a throughput of at least 400 pounds of beef per week. For underfired charbroilers, Rule 2 applies to new and existing restaurants with underfired charbroilers with an aggregate grill surface area of ten (10) square feet that purchase more than 1,000 pounds of beef per week and cook 800 pounds of beef/week. For such underfired charbroilers, the rule requires operators to control emissions using a certified control device that limits PM_{10} emissions to no more than 1 pound of PM_{10} per 1,000 pounds of beef cooked. While the rule's requirements for chain-driven charbroilers have been successfully implemented, the same is not true for underfired charbroilers. Most underfired charbroilers fall below the eligibility thresholds, and there is a lack of certified control devices.[241,242]

The South Coast Air Quality Management District adopted Rule 1138 (Control of Emissions from Restaurant Operations) in 1997 to control emissions from chain-driven charbroilers only.[243] The Rule requires the use of catalytic oxidizers to control PM_{10} emissions from chain-driven charbroilers but does not set a specific emission limit. Since adopting Rule 1138, SCAQMD staff examined underfired charbroilers and made a series of reports to the SCAQMD Governing Board (from 1999 to 2004), to present results of underfired charbroiler control technology research. To date, a variety of control device technologies have been tested, and SCAQMD staff has also reviewed existing and proposed underfired charbroiler control programs undertaken by other regions.[244] Due to the lack of demonstrable cost-effective technology, SCAQMD's 2016 Air Quality Management Plan included a rule for underfired charbroilers only as a contingency measure if they fail to reach attainment. The SCAQMD has yet to adopt this contingency measure. [245]

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[239] To the extent that there may be chain-driven charbroilers in the Nonattainment Area, EPA already accepted the State's analysis that catalytic oxidizers are economically infeasible control measures for the FNSB Nonattainment Area. 88 Fed. Reg. at 1480.
[240] Bay Area Air Quality Management District, Regulation 6 – Particulate Matter Rule 2 Commercial Cooking Equipment, http://www.baaqmd.gov/~/media/dotgov/files/rules/reg-6-rule-2-commercial-cooking-equipment/documents/rg0602.pdf?la=en, accessed on June 21, 2018.
[241] BAAQMD, 2013. Unfired Charbroilers. Accessed at https://www.baaqmd.gov/~/media/files/compliance-and-enforcement/advisories/restaurants/underfired-charbroiler-advisory-final-1-18-13.pdf?la=en.
[242] SJVUAPCD, 2020 District Staff Report. Accessed at https://www.valleyair.org/Board_meetings/GB/agenda_minutes/Agenda/2020/December/final/11.pdf.
[243] SCAQMD. Rule 1138. Accessed at http://www.aqmd.gov/docs/default-source/rule-book/reg-xi/rule-1138.pdf?sfvrsn=4.
[244] SCAQMD, 2009. Proposed Amended Rule 1138. Accessed at http://www.aqmd.gov/docs/default-source/rule-book/support-documents/rule-1138/par1138pdsr.pdf.
[245] SCAQMD, 2016. Air Quality Management Plan, Appendix IV-C. Accessed at http://www.aqmd.gov/docs/default-source/clean-air-plans/air-quality-management-plans/2016-air-quality-management-plan/final-2016-aqmp/appendix-iv-a.pdf?sfvrsn=4.

The San Joaquin Valley Unified Air Pollution Control District (SJVUAPCD)'s Rule 4692 (Commercial Charbroiling), adopted in 2002, requires the installation and operation of control devices on chain-driven commercial charbroilers that cook 400 pounds of meat or more per week. [246] **The emissions control devices are required to achieve 83% control efficiency for PM and 86% control efficiency for VOC. Since then, the District has extensively researched the possibility of imposing similar requirements for underfired charbroiling operations, by identifying different viable control technologies and evaluating their technological and economic feasibility. However, the unavailability of a feasible and cost-effective control technology has been a barrier to establishing these requirements.**

As part of SJUAPCD's 2009 amendments to Rule 4692, the District determined that control techniques (ESP, filtration, and wet scrubbers) for underfired charbroilers were unproven and extremely costly.[247] **Since 2009, the district initiated a Charbroiler incentive program and formed a Restaurant Charbroiler Technology Partnership ("RCTP") to identify potential technology vendors and reach out to restaurant owners.**[248] **Despite the District's efforts in promoting the RCTP program, the District has faced difficulty in finding restaurants willing to partner with the District to evaluate the control technologies.**[249] **In 2018, due to the lack of economic and technologically feasible controls, the district amended Rule 4692**[250]**, to require underfired charbroiler operators to submit a one-time report, mentioned above, as well as permit-exempt equipment registration for units with a meat throughput greater than 400 pounds/week, or greater than 10,800 pounds/year, not to exceed 875 pounds/week. EPA approved these amendments to Rule 4982 in 2020.**[251] **In their 2020 staff report, the District adopted an emission reduction strategy for underfired charbroiling, including incentives, providing guidance to cities and counties, and assisting the California Air Resources Board in developing a statewide control measure.**

As of December 2022, the district has not identified a cost-effective control technology for regulating underfired broiler charbroiling emissions.[252] **In their latest 2023 Initial $PM_{2.5}$ SIP, the District reevaluated additional control technologies such as regenerative filters,**

[246] SJVUAPCD, Rule 4692: Commercial Charbroiling (Adopted March 21, 2002; Amended September 17, 2009; Amended June 21, 2018), at 4692-1. Accessed at https://www.valleyair.org/rules/currntrules/r4692.pdf.
[247] SJUAPCD, 2015 Plan for the 1997 $PM_{2.5}$ Standard. Appendix C: BACM and MSM for Stationary and Area Sources. Accessed at http://www.valleyair.org/Air_Quality_Plans/docs/PM25-2015/C.pdf.
[248] SJVUAPCD, 2017 District Staff Report. Accessed at http://www.valleyair.org/Board_meetings/GB/agenda_minutes/Agenda/2017/September/final/10.pdf.
[249] SJVUAPCD, 2020 District Staff Report. Accessed at https://www.valleyair.org/Board_meetings/GB/agenda_minutes/Agenda/2020/December/final/11.pdf.
[250] SJVUAPCD, 2018 $PM_{2.5}$ Plan. Accessed at https://www.valleyair.org/pmplans/documents/2018/pm-plan-adopted/2018-Plan-for-the-1997-2006-and-2012-PM2.5-Standards.pdf.
[251] Federal Register Notice, 2020. Accessed at https://www.federalregister.gov/documents/2020/05/29/2020-11261/air-plan-approval-california-san-joaquin-valley-unified-air-pollution-control-district-and-feather.
[252] Based on communication with Kevin M. Wing on December 10, 2022, Senior Air Quality Specialist, Air Quality Science and Planning, SJUAPCD.

and wool filters to reduce emissions from underfired charbroilers.[253] The District continued to find the control technologies economically infeasible.

The Utah Department of Environmental Quality (UDAQ) last amended R307-303 (Commercial Cooking) in 2018 to control $PM_{2.5}$ emissions from chain-driven charbroilers in $PM_{2.5}$ nonattainment counties.[254] This regulation requires the use of catalytic oxidizers on all chain-driven charbroilers in these jurisdictions, regardless of meat processing capacity. The regulation also requires that the opacity of exhaust from catalytic oxidizers serving chain-driven charbroilers not exceed 20% using U.S. EPA Method 9. As part of its BACM analysis in 2020, UDAQ evaluated the control technologies for underfired charbroilers and found none of the technologies to be economically feasible for implementation, and thus the Rule does not cover underfired charbroilers.[255]

New York City Department of Environmental Protection (NYCDEP): NYC Code Rule 24-149.4 prohibits operation of any new commercial charbroiler, or existing chain-driven commercial charbroiler, to cook more than 875 pounds of meat per week unless it is equipped with an emission control device.[256] Pursuant to this rule in the city code, NYCDEP promulgated more specific rules for underfired charbroilers.[257] No person may operate any new underfired commercial charbroiler to cook more than 875 pounds of meat per week unless an ESP or other emissions control device, that has been tested and certified, has been installed. As of July 2020, NYCDEP informed EPA that it was not aware of any new restaurants that had installed controls for underfired charbroilers.[258] As of late 2020, San Joaquin Valley air quality staff were aware that NYCDEP was working with the New York City Department of Buildings to require the installation of a certified control device prior to new restaurants opening, as part of the permitting process.[259] Based on staff-level discussions, the retrofit installation of control devices on existing operations was not being required at that time.

Based on the review of regulations for underfired charbroilers, ADEC found no practical demonstration of cost-effective control technology by any air quality agency. Based on

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253 SJVUAPCD, 2023. Initial SIP Requirements for the 2012 Annual $PM_{2.5}$ Standard. Accessed at https://ww2.valleyair.org/rules-and-planning/air-quality-plans/particulate-matter-plans/2023-pm25-plan-for-the-san-joaquin-valley/.
254 UDAQ. Rule 307-303. Accessed at https://rules.utah.gov/publicat/code/r307/r307-303.htm.
255 UDAQ 2020 Technical Support Document (TSD), Accessed at https://www.regulations.gov/document/EPA-R08-OAR-2020-0098-0015.
256 NYC Rule 24-149.4 Commercial charbroilers. Accessed at https://codelibrary.amlegal.com/codes/newyorkcity/latest/NYCadmin/0-0-0-42985.
257 NYCDEP, Notice of Adoption of Final Rule (2016). Accessed at http://donerighthfs.com/wp-content/uploads/2018/03/commercial-char-broiler-rule.pdf.
258 EPA Region 8, Technical Support Document: Proposed Action on the Area Source Rule Revisions, Emission Limit Revisions, Inspection and Maintenance (I/M) Program Revisions, and Best Available Control Measure/Best Available Control Technology (BACM/BACT) Determinations within Utah's Salt Lake City and Provo 2006 24-Hour PM2.5 State Implementation Plans, (October 2020) available at https://www.regulations.gov/document/EPA-R08-OAR-2020-0098-0015.
259 SJVAPCD, Memorandum re: Item Number 11: Adopt Proposed Commercial Underfired Charbroiling Emissions Reduction Strategy (December 17, 2020), at 8, available at https://www.valleyair.org/Board_meetings/GB/agenda_minutes/Agenda/2020/December/final/11.pdf.

EPA's suggestion and its review of the SIPs and survey of local authorities, ADEC evaluated the feasibility of electrostatic precipitators (ESPs), wet scrubbers, and filtration as potential control technologies for underfired charbroilers.

ADEC researched the technological feasibility of installing control devices (ESPs, wet scrubbers, and filtration) in Fairbanks Nonattainment Area for underfired charbroilers by contacting vendors. The vendors identified issues related to both shipping and maintenance of the control technology. Due to the size of the control technologies, shipping to Alaska is often prohibitive and certainly vastly different than shipping within the lower-48. Vendors may be able to ship required hardware to the nearest port, but beyond that, is the customer's responsibility to get the hardware delivered to its place of use. This, again, imposes challenges unique to Alaska in both scale and required services to do so. In addition to shipping issues, there is no available personnel with sufficient training to maintain these technologies. The service of this technology is complex and requires service companies or trained staff to be available locally, neither of which currently exist in the Nonattainment Area. Further, delays in required maintenance lower the efficiency of the control technologies. A combination of review of other air quality regulations, and barriers to installation and maintenance of control devices makes this measure technologically infeasible.

Although ADEC dismissed this measure based on technological infeasibility, ADEC also evaluated the economic feasibility for ESP, filtration, and wet scrubbers. ADEC developed cost-effectiveness estimates based on the methodology followed by SJUAPCD and using cost estimates specific to Alaska. ADEC analyzed the cost-effectiveness of these control technologies based on the most comprehensive economic analysis available, which was developed by SJVAPCD in its 2018 $PM_{2.5}$ Plan[250] and 2020 Staff Report[242]. ADEC adjusted the costs for inflation and the difference in labor costs between California and Alaska, plus projected shipping costs from the continental United States to Alaska.

SJVAPCD reported cost estimates for ESP and filtration technologies as a range rather than a single number due to the wide range of variables involved in the cost estimates, including equipment type, simple or complicated configuration, age of the restaurant's infrastructure, and more. Installing new controls on existing restaurants can be expensive, requiring structural, electrical, or plumbing modifications, compared to new restaurants that can integrate emission controls into the design. Based on SJVAPCD's reasoning, ADEC chose to use this same approach of presenting cost-effectiveness as a range rather than as a single number.

For the Fairbanks Nonattainment Area, ADEC found the range of cost-effectiveness for installing an ESP for an underfired charbroiler to be between $40,343 and $528,940 per ton of $PM_{2.5}$ removed, based on a removal efficiency of 86%.[260] ADEC found the range of cost-effectiveness of installing a filtration system for an underfired charbroiler to be between

[260] SCAQMD, Appendix IV-A, 2016. Accessed at http://www.aqmd.gov/docs/default-source/clean-air-plans/air-quality-management-plans/2016-air-quality-management-plan/final-2016-aqmp/appendix-iv-a.pdf?sfvrsn=4, Pg. IV-A-186. As the removal efficiency information was not available from the SJVUAPCD 2018 and 2020 reports, the latest information from the SCAQMD's 2016 Air Quality Plan was utilized.

$43,369 and $568,610 per ton of PM removed, based on a removal efficiency of 80%. The cost-effectiveness analysis for filtration represents wet scrubbers, because wet scrubbers require filtration. A wet scrubber is essentially a fine stream of water and detergent that washes the particulates from the underfired charbroiler's exhaust, which passes through a filtration system before discharging to the sewer. Therefore, the cost estimates developed for ESP and filtration systems conservatively represent the cost estimates for wet scrubbers, because wet scrubbers are an additional cost upstream of filtration systems.[261]

These costs per ton are prohibitive for restaurants using underfired charbroilers in the Nonattainment Area. Under the higher standard that applies to BACM, imposing ESPs, wet scrubbers, and filtration on underfired charbroilers in the Nonattainment Area is economically infeasible.

Conclusion

The BACM conclusion of these measures is unchanged from the 2020 Amendments. Installing emissions control devices such as ESP, filtration, and wet scrubbers for underfired charbroilers continues to be both technologically and economically infeasible for the Nonattainment Area. ADEC based its prior analysis on chain-driven charbroilers and found that catalytic oxidizers were technologically but not economically feasible as BACM. EPA approved this aspect of ADEC's analysis.[262] Updated information and further research indicated the presence of only underfired charbroilers in the Nonattainment Area, and the controls for underfired charbroilers are different. ADEC evaluated the technological and economic feasibility analysis for ESP, filtration systems, and wet scrubbers for underfired charbroilers and found all controls to be technologically and economically infeasible as BACM.

The adoption of the referenced state regulations are sufficient to meet the BACM requirements of this measure, therefore the measure is technologically feasible and eligible for Step 4 cost effectiveness analysis. The Step 4 analysis of the information collected under 18 AAC 50.078(c) found that installing catalyst oxidizers on charbroiling facilities is not cost effective, and therefore not eligible for consideration as a 2020 Amendment Plan control measure.

Measure 69: Incinerators

Implementing Jurisdiction(s)

- South Coast AQMD
- Washington State
- Colorado
- New York State

[261] SJVUAPCD combined the cost estimates for both ESP and filtration. ADEC used the cost estimates reported by SJVUAPCD but separated the technologies based on their removal efficiencies as filtration has a lower removal efficiency compared to ESP and estimated the cost-effectiveness estimates.

[262] 88 Fed. Reg. at 1480. Technical Support Document: Docket No. EPA-R10-AOAR-2022-0115.

Regulation Weblink(s)

- See listed footnotes below

Background

The Alaska Department of Environmental Conservation, under the Alaska Administrative Code 18.AAC.50.050 – Incinerator Emission Standards, PM emissions are restricted to the levels, which vary with the size of the facility, that are shown in the following table:[263]

Incinerator	Particulate Matter Standard
Rated capacity less than 1,000 pounds per hour	No limit
Rated capacity greater than or equal to 1,000 but less than 2,000 pounds per hour	0.15 grains per cubic foot of exhaust gas corrected to 12 percent carbon dioxide and standard conditions, averaged over three hours
Rated capacity greater than or equal to 2,000 pounds per hour	0.08 grains per cubic foot of exhaust gas corrected to 12 percent carbon dioxide and standard conditions, averaged over three hours
An incinerator that burns waste containing more than 10 percent wastewater treatment plant sludge by dry weight from a municipal wastewater treatment plant that serves 10,000 or more persons	0.65 grams per kilogram of dry sludge input

These restrictions were most recently amended in 2008.

Under a regulation last amended in 1992, San Joaquin Valley APCD Rule 4203 (Particulate Matter Emissions From Incineration of Combustible Refuse) restricts particulate matter emissions from refuse incinerators to less than 0.10 pounds per 100 pounds of refuse burned. [264] The rule also limits particulate emissions to 0.10 grains per dry standard cubic foot (gr/dscf) of exhaust gas corrected to 12% CO_2 for incinerators having burn rates in excess of 100 pounds per hour, and to 0.30 gr/dscf corrected to 12% CO_2 for incinerators having burn rates less than or equal to 100 pounds per hour.

[263] Alaska Administrative Code Title 18, Environmental Conservation, Chapter 50 Air Quality Control, available at https://www.epa.gov/sites/production/files/2017-10/documents/sip-ak-approved-regulations-18-aac-50.pdf, accessed April 16, 2018

[264] San Joaquin Valley Unified Air Pollution Control District, Rule 4203 Particulate Matter Emissions from Incineration of Combustible Refuse (Adopted May 21, 1992, Amended December 17, 1992), available at http://www.valleyair.org/rules/currntrules/r4203.pdf, accessed April 12, 2018

South Coast AQMD Rule 473 (Disposal of Solid and Liquid Wastes) imposes similar particulate matter emission limits on incinerators.[265] For incinerators with design combustion rates greater than 110 pounds per hour, the emission limit is 0.1 gr/dscf corrected to 12% CO_2. For incinerators with design combustion rates less than or equal to 110 pounds per hour, the emission limit is 0.3 gr/dscf corrected to 12% CO_2.

The Washington Department of Ecology Rule 173-434-130 (Solid Waste Incinerator Facilities) requires that incinerators capable of burning 250 or more tons of solid waste per day emit no more than 0.020 gr/dscf corrected to 7% O_2, and that incinerators capable of burning more than 12 tons but less than 250 tons of solid waste per day emit no more than 0.030 gr/dscf corrected to 7% O_2. In addition, Rule 173-434-160 requires the combustion zone temperature not fall below 1600 degrees F, or not average less than 1800 degrees F over any fifteen-minute period, or that the combustion air leaving the chamber must maintain an oxygen concentration of at least 3% on a wet basis.[266]

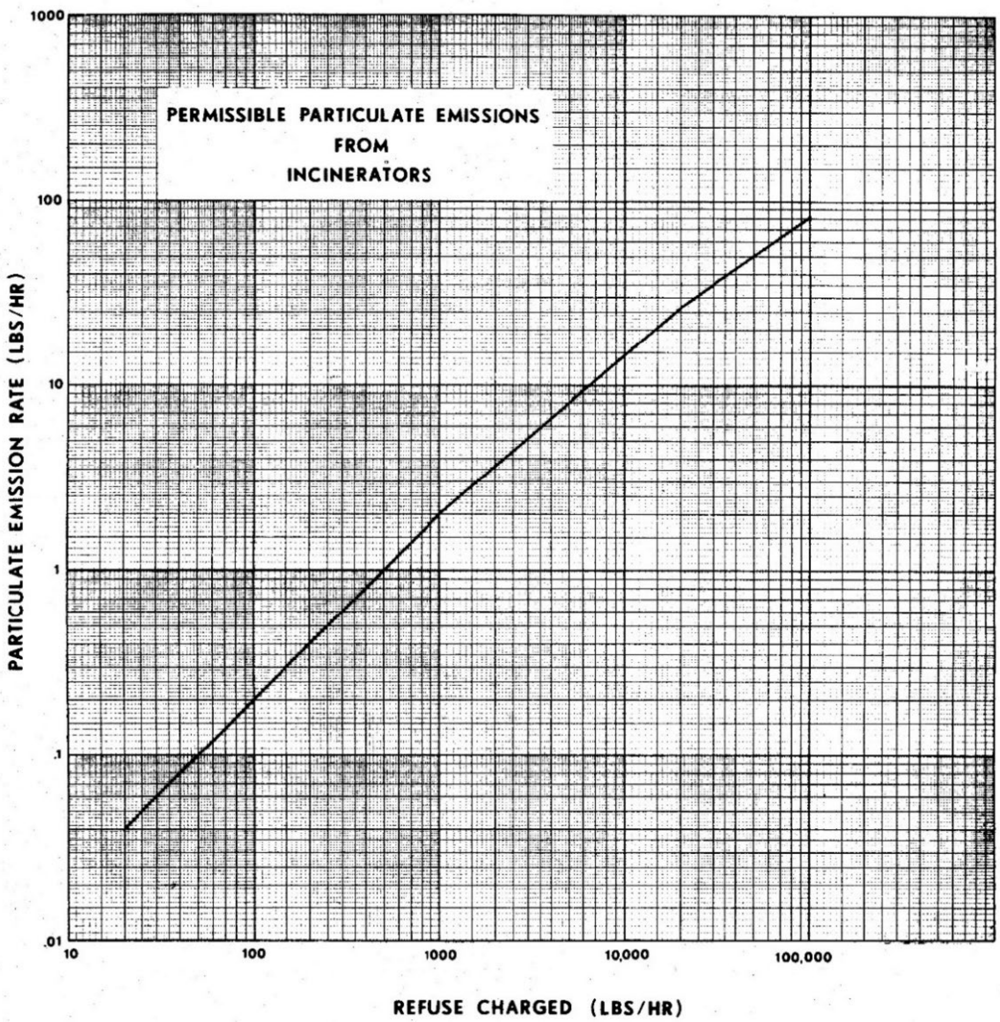
Restrictions similar to those in Alaska have been adopted by the Colorado Department of Public Health & Environment, where - in areas designated as non-attainment or attainment/maintenance for particulate matter - no owner or operator of an incinerator is allowed to cause or permit particulate matter emissions of more than 0.10 gr/dscf corrected to 12 % CO_2. In areas designated as attainment for particulate matter, the emission limit is 0.15 gr/dscf corrected to 12 % CO_2.[267]

San Diego County Air Pollution Control District Rule 53 limits combustion particulate emissions from incinerators to 0.10 gr/dscf corrected to 12% CO_2, except for those with a rated capacity of 100 pounds per hour or less, which are limited to 0.30 gr/dscf corrected to 12% CO_2.[268]

New York State Department of Environmental Conservation Codes, Rules and Regulations Chapter III, Part 219 (Incinerators), Subpart 2.2 (Emission Limitations) limits particulate matter emissions from incinerators statewide to 0.010 gr/dscf corrected to 7% O_2. Subpart 6.2 (Existing Incinerators – New York City, Nassau and Westchester Counties; Particulate Emissions) limits particulate emissions from existing incinerators to values displayed in the following figure:

[265] http://www.aqmd.gov/docs/default-source/rule-book/rule-iv/rule-473.pdf?sfvrsn=4, accessed on June 25, 2018.
[266] Washington State Legislature, Chapter 173-434, Solid Waste Incinerator Facilities, available at http://apps.leg.wa.gov/wac/default.aspx?cite=173-434&full=true, accessed April 12, 2018
[267] Colorado Department of Public Health and Environment, Air Quality Control Commission, Regulation No. 1 Emission Control for Particulate Matter, Smoke, Carbon Monoxide, and Sulfur Oxides 5 CCR1001-3, 2007, available at https://www.colorado.gov/pacific/sites/default/files/5-CCR-1001-3.pdf, accessed April 12, 2018
[268] San Diego County Air Pollution Control District, Rule 1. Title, available at https://www.epa.gov/sites/production/files/2018-01/documents/san_diego_county_air_pollution_control_district_apcd_rules_compilation_dec_2017.pdf, accessed April 16, 2018

FIGURE 1



New York State DEC regulations also limit particulate emissions for existing incinerators in other portions of the state to values displayed in a different, less restrictive figure. Other sections of Part 219 place restrictions on the O_2 and CO_2 exhaust content and minimum combustion temperatures, among other requirements.[269]

Analysis

The regulatory emission limitations of particulate matter from incinerators enforced by San Joaquin Valley APCD, South Coast AQMD, San Diego County APCD, Washington State DEQ, Colorado DPHE, and New York State DEC are all more restrictive than those applicable to incinerators in Fairbanks and are therefore technologically feasible.

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[269] Westlaw Compilation of New York Codes, Rules, and Regulations, Subpart 219-2 Municipal and Private Solid Waste Incineration Facilities, available at https://govt.westlaw.com/nycrr/Browse/Home/NewYork/NewYorkCodesRulesandRegulations?guid=Ib66e7530b5a011dda0a4e17826ebc834&originationContext=documenttoc&transitionType=Default&contextData=(sc.Default)&bhcp=1, accessed April 12, 2018.

In the Serious Area SIP, regulation 18 AAC 50.078(c) was adopted which required incinerators to submit information on location, type (medical, liquid, solid, etc.), process, fuel, throughput, hours of operation, etc. The Serious Area SIP committed to surveying potential sources and evaluating the results to determine if more stringent incinerator regulations are required.

After the Serious Area SIP was adopted ADEC sent 129 requests for information to businesses that may have an incinerator. ADEC received 39 responses to the requests for information. Of the 39 responses received, 36 verified that there is no incinerator present at the business location and 3 verified that there is an incinerator present at the location. The sources identified as incinerators were:

Device Make & Model	**Source Type**	**Process Description**	**Operating Hours**
Omni EH-350	Used Oil	Burning of Used Oil	30
Home Made	Cardboard & Paper	Burning	3hr/2week
Home Made	Wood-Brush	Manual Load	Summer use only

The Omni EH-350 used oil burner is addressed under Measure 70: Used Oil Burners and is not considered an affected source for the purposes of this analysis. The homemade cardboard and paper burner is the equivalent of a residential burn barrel and not an affected source under the incinerator source category. The homemade wood-brush burner operates seasonally with only summer usage and does not contribute to winter-time air pollution episodes and is therefore not considered an affected source.

ADEC does not have any record of permitted sources under the incinerator source category. Therefore, there are no existing incinerators to be affected by a regulation change.

Conclusion

The final PM2.5 implementation rule 51.1010(c)(1) and (2) reads in part "The state shall identify all sources of direct PM2.5 emissions… The state shall identify all potential control measures to reduce emissions from all sources…" This control measure does not control emissions from any source within the nonattainment area and is therefore dismissed from the control strategy analysis requirements for the 2020 Amendment Plan.

Measure 70: Used Oil Burners

Implementing Jurisdiction(s)

- **State of Vermont**

Regulation Weblink(s)

- https://dec.vermont.gov/sites/dec/files/aqc/laws-regs/documents/AQCD%20Regulations%20ADOPTED_Dec132018.pdf

Background

ADEC identified measures regulating used oil burning – Measures 52, 53, and 70 in the 2020 amendments to the Serious SIP – implemented by the State of Vermont, and ADEC analyzed the feasibility of these measures as part of its submitted BACM analysis.[270] Measures 52 and 53 addressed controls mandated by the State of Vermont prohibiting the burning of used fuel oil in small "pot burners" or vaporizing burners. Both measures were determined to be technologically and economically infeasible, given the local conditions in Fairbanks and the cost-effectiveness analysis. EPA concurred with ADEC's determination on both measures.[271]

During the development of the Serious Area SIP, while considering a set of regulations governing the accumulation, distribution, and burning of used oil, it was determined that little information is available about the extent of used oil burning in Fairbanks. Calls to local vendors confirmed that used oil is burned, however, no detailed information about the number of facilities and homes burning waste oil or the volumes used had been collected. Following this, ADEC gathered information on the used oil through the adoption of regulation 18 AAC 50.078(c)[272] which required used oil burners to submit information on the location, # of burners, rating, operating hours, fuel use/hour, etc. ADEC also contacted the local used oil marketer and FNSB Solid Waste manager and obtained information on the disposal methods of used oil available in the Nonattainment Area.

Based on the information obtained, ADEC concluded that the combustion of used oil is the only acceptable disposal method available in the FNSB without shipping the used oil to the lower-48. Prohibiting or regulating the combustion of used oil in the FNSB would place a burden on the small businesses that rely on the combustion of used oil as a waste disposal method, encouraging a small percentage to improperly dispose of the used oil. Due to the severe environmental impacts used oil can have on waterways and drinking water, and the probability that prohibiting or regulating the combustion of used oil would lead to improper disposal, ADEC dismissed measure 70 from consideration for the 2020 Amendment to the Serious SIP as technically infeasible due to potential environmental impacts.

EPA in their Comments on 2020 Amendments[273] rejected ADEC's dismissal of measure 70 by stating that the State and EPA have the authority to mitigate potential environmental impacts that may occur from illegal oil burning. EPA also recommended that ADEC

[270] Alaska Department of Environmental Conservation, "Amendments to: State Air Quality Control Plan; Vol. III: Appendix III.D.7.7" (November 18, 2020) (hereinafter "2020 BACM Analysis"), at 5397-5399, 5427-5429.

[271] 88 Fed. Reg. 1481. Technical Support Document: Docket No. EPA-R10-AOAR-2022-0115.

[272] https://dec.alaska.gov/media/1038/18-aac-50.pdf.

[273] 88 Fed. Reg. at 1480. Technical Support Document: Docket No. EPA-R10-AOAR-2022-0115.

evaluate the feasibility of requiring used oil generators to collect and ship used oil to a central processing facility in Anchorage.

Following EPA's comments, ADEC revisited local efforts and conducted a technological and economic analysis of alternative ways to process used oil that were not analyzed in the 2020 amendments to the Serious SIP. The economic feasibility analysis determined that the processing of used oil would produce cost-effectiveness estimates for $PM_{2.5}$ emissions reduction that are infeasible and ADEC dismissed measure 70 as BACM.

EPA in their Final Rule[274] found ADEC's analysis to fill the analytical gaps noted in EPA's comments and agreed that banning used oil burners is economically infeasible as BACM at this for the Nonattainment Area. EPA recommended that for used oil emission estimates, there are considerably more SO_2 than $PM_{2.5}$ emissions, and economic analysis when based on SO_2 would provide a more reasonable estimate of benefits. Accordingly, ADEC updated the economic analysis to include SO_2 emissions that resulted in cost-effectiveness estimates that are infeasible for implementation.

Analysis

Used oil is a waste stream which can pollute the environment if not recycled or disposed of properly. Used motor oil is insoluble, persistent, and can contain toxic chemicals and heavy metals. It is a major source of oil contamination of waterways and can result in pollution of drinking water sources. Used oil from one oil change can contaminate one million gallons of fresh water – a years' supply for 50 people[275]. Known methods of used oil disposal include[276]:

- **Reconditioned on site – Impurities are removed from the used oil, which is then reused. While this form of recycling might not restore the oil to its original condition, it does prolong its life.**
- **Inserted into a petroleum refinery – Used Oil is introduced as a feedstock into refinery production processes.**
- **Re-refined – Involves treating used oil to remove impurities so that it can be used as a base stock for new lubricating oil. Re-refined prolongs the life of the oil resource indefinitely. This form of recycling is the preferred option because it closes the recycling loop by reusing the oil to make the same produce that it was when it started out, and therefore uses less energy and less virgin oil.**
- **Processed and burned for energy recovery – Involves removing water and particulates so that used oil can be burned as fuel to generate heat or to power industrial operations. This form of recycling is not as preferable as methods that reuse the material because it only enables the oil to be reused once. Nonetheless, valuable energy is provided (about the same as provided by normal heating oil).**

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[274] 88 Fed. Reg. at 84626.

[275] U.S. Environmental Protection Agency: Managing, Reusing, and Recycling Used Oil, https://www.epa.gov/recycle/managing-reusing-and-recycling-used-oil, accessed 8/21/2020

[276] U.S. Environmental Protection Agency: Managing Used Oil: Answers to Frequent Questions for Businesses, https://www.epa.gov/hw/managing-used-oil-answers-frequent-questions-businesses, accessed 8/21/2020.

The primary Federal regulations that apply to used oil are set out at 40 CFR Part 279. As described in a 2020 Department of Energy (DOE) report to Congress, EPA's regulations establish a set of "good housekeeping" requirements for used oil handlers; establish streamlined procedures for notification, testing, labeling, and record-keeping; establish a flexible approach for tracking offsite shipments that allow used oil handlers to employ standard business practices; and set standards for the prevention and cleanup of releases to the environment during used oil storage and transit.[277]

40 CFR Part 279 establishes a structure to minimize the potential mismanagement of used oil without discouraging recycling. Most states, including Alaska,[278] have adopted 40 CFR Part 279. The 2020 DOE report analyzed the key elements of state practices on used oil collection practices and programs. The report acknowledges that while states "have made progress in supporting used oil collection and management . . . there are still areas of the country where used oil recycling remains challenging," and "it is difficult to identify one solution as a model that could be used across the country." The report also indicates that a key factor impacting the recycling of used oil is the convenience of recycling facilities. DOE's conclusions are consistent with ADEC's analysis, further discussed below, which demonstrates that shipping used oil to a central disposal facility (and, alternatively, operating a centrifuge facility in Fairbanks, another option evaluated for used oil disposal) is infeasible given costs and local conditions.

In the Serious Area SIP, regulation 18 AAC 50.078(c)[279] was adopted which required used oil burners to submit information on the location, # of burners, rating, operating hours, fuel use/hour, etc. After the Serious Area SIP was adopted, ADEC sent 129 requests for information to businesses that may have a used oil burner. ADEC received 47 responses to the requests for information. Of the 47 responses received, 31 verified that there is no used oil burner present at the business location and 16 verified that there is a used oil burner present at the location. Some businesses had multiple used oil burners for a total of 19 used oil burners. Fuel source was reported as 18 from auto/engine oil and 1 with a mix of restaurant oil with auto/engine oil. Fuel quality reported contained varied results including "filtered", "raw", "good", "high", and "excellent". Due to the varied results the fuel quality is not useful information. Operating hours varied from 2 to 24 hours per day. No control equipment was reported. Fuel usage ranged from 0.25 gal/hr to 3.0 gal/hr with an average of 1.61 gal/hr.

The environmental concerns with used oil disposal were brought up by the Air Quality Stakeholders group during Serious SIP development in the fall of 2018. Used oil control measures were not included in the final recommended control package for the Serious SIP in part due to environmental concerns because there was no alternate disposal method

[277] U.S. Department of Energy, "Used Oil Management and Beneficial Reuse Options to Address Section 1: Energy Savings from Lubricating Oil Public Law 115-345; Report to Congress" (December 2020) (hereinafter "2020 DOE Report"). Accessed at https://www.energy.gov/sites/prod/files/2020/12/f81/Used%20Oil%20Management%20and%20Beneficial%20Reuse%20Options%20to%20Address%20Section%201.%20E .... pdf.
[278] 18 AAC 62.511 (adopting 40 CFR Part 279 by reference).
[279] https://dec.alaska.gov/media/1038/18-aac-50.pdf.

available other than burning the used oil. Air Quality Stakeholders were concerned that small businesses may improperly dispose of the used oil resulting in environmental damage if combustion of used oil was regulated.

Following this, during the development of the 2020 Amendments, ADEC contacted the Environmental Compliance Consultants (ECC), a local used oil marketer, to determine disposal methods available in the FNSB. Used oil is collected in the FNSB and stored in holding tanks, there are no processing or recycling facilities in the FNSB. Used oil is transferred overland to ECC's Anchorage facility where it is run through a low-temperature heating and filtration system to reduce the basic sediment and water content before being sold for energy recovery to industrial clients. According to ECC, all used oil in Alaska is processed and burned for energy recovery, and if the used oil is not going to be burned it must be shipped to the lower 48 for recycling.

Additionally, ADEC contacted the FNSB Solid Waste manager to determine how the FNSB disposes of used oil received at the landfill. Prior to Fiscal Year 2020-2021, FNSB operated multiple used oil burners where all used oil collected from landfill operations and FNSB Transportation/Transit operations was filtered then combusted for space heating needs. The FNSB Solid Waste Department transitioned to an alternate disposal method in Fiscal Year 2020-2021. All used oil collected is first shipped to an Emerald collection center in Seattle, WA then shipped to its final destination, Green American Recycling, LLC at one of their cement plants in either Iowa or Missouri.

Based on this information, ADEC concluded that any disposal method other than burning the used oil for energy recovery to be technological infeasible as these methods will require overland transportation. Overland transportation on roadways connecting interior Alaska to Anchorage has several challenges in terms of the rough winter driving conditions, and issues of accidental spillage of the oil that results in environmental damage. Any disposal method that requires an increase in overland transportation will also increase the risk of environmental damage. Based on these findings, ADEC dismissed measure 70 from consideration for the 2020 Amendments based on technological infeasibility.

Following EPA's rejection of ADEC dismissal of measure 70,[280] ADEC evaluated the technological and economic feasibility of shipping used oil via the FNSB Solid Waste Division facility (Option 1). In addition, ADEC also evaluated the option of purchasing, operating, and maintaining a centrifuge facility in Fairbanks to process used oil from all used oil generators in the community (Option 2).

In evaluating both options, ADEC reviewed data from a 2010 survey and the data obtained as part of 18 AAC 50.078(c) regulation.[281] In 2010, ADEC surveyed 25 local auto shops on used motor oil usage data. The survey estimated the total amount of unprocessed used motor oil used for burning purposes to be 135,100 gallons per year. Between the two data collection efforts, ADEC found the survey information obtained in 2010 to be

[280] 88 Fed. Reg. at 1480. Technical Support Document: Docket No. EPA-R10-AOAR-2022-0115.
[281] https://dec.alaska.gov/media/1038/18-aac-50.pdf.

comprehensive and based its evaluation of Options 1 and 2 on this information. In evaluating economic feasibility, ADEC relied on: (1) 2010 survey data discussed above; (2) information obtained from FNSB Solid Waste Division; (3) information obtained from commercial vendors; and (4) data queried from public online databases. ADEC only accounted for non-hazardous used oil (containing <1000 ppm halogens) and did not factor into the evaluation either the charge on the front end for collecting used oil and the back end of profit obtained by selling the processed oil at a discounted market price.

Option 1: First, ADEC reviewed available information to determine what recycling facilities in Fairbanks accept used oil. According to a 2015 recycling report prepared for the Fairbanks North Star Borough's ("FNSB") Solid Waste Division,[282] used oil is accepted by the following: (1) Eielson Air Force Base; (2) Fort Wainwright; and (3) the FNSB recycling facility. The Eielson Air Force Base ("EAFB") collects used cooking oil, lead acid batteries, and scrap metal at both a central receiving center and satellite centers with dumpsters for different materials. Historically, participation has been voluntary, and the vast majority of participants are residents of the base military housing. Fort Wainwright ("FTW") recycles brass, lead-acid batteries, and waste oil, and FTW has used private companies to ship the recyclables to Fort Richardson in Anchorage. ADEC contacted both facilities and confirmed that neither EAFB nor FTW accept used oil for disposal from off-base community residents and other entities. FTW also informed ADEC that the facility's used oil burners have been decommissioned. Therefore, ADEC is not evaluating these facilities as potential options to dispose of used oil.

Next, ADEC reviewed available information to determine what recycling facilities in Fairbanks accept used oil and found only the FNSB Solid Waste Division to accept waste motor oil.[283] Based on discussion with the FNSB Solid Waste Division,[284] the facility ships used oil collected from residents and very small quantity generators (VSQGs)[285] to a central facility in Anchorage; charges shipping costs of $0.95/gallon with < 1000ppm halogens, and $3.58/gallon to ship used oil with >1000ppm halogens. The facility charges only for shipping costs and does not do any processing or re-refining of used oil and does not incur any monetary gain from processing or sale of used oil. Although the option of shipping to this facility existed before ADEC submitted its 2020 amendments to the Serious SIP, ADEC did not assess its feasibility as a control measure.

ADEC found Option 1 to be partially technologically feasible because the FNSB Solid Waste Division facility accepts used oil from residents and very small quantity generators which are limited to 26 gallons (approximately 100 kilograms) of used oil per month and

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[282] PDC Inc. Engineers, "Recycling Plan & Analysis," prepared for Fairbanks North Star Borough Solid Waste Division (June 12, 2015) (hereinafter "2015 FNSB Recycling Report"). Accessed at https://www.fnsb.gov/DocumentCenter/View/1262/2015-PDC-Recycling-Plan-and-Analysis-PDF.
[283]Fairbanks North Star Borough, Solid Waste Division, "Solid Waste Management," Accessed at https://fnsb.gov/288/Solid-Waste.
[284] Discussion with Shann Paul Jones, Assistant Solid Waste Manager and Landfill Engineer with FNSB Solid Waste Division. Date: November 08, 2022.
[285] Very small quantity generators (VSQG) are those that generate less than 100 kilograms per month of hazardous waste, less than 1 kilogram per month of acute hazardous waste, and less than 100 kilograms per month of acute spill residue on soil. *See* 40 C.F.R. § 262.

does not accept used oil from large-quantity generators producing greater than 26 gallons per month. Due to this limitation, ADEC would have to explore other alternatives for large-quantity generators of used oil. In evaluating economic feasibility, ADEC assumed the emissions reduction to be 50% since there is no information on the fraction of used oil used for direct combustion versus disposal (while shipping the used oil compared to disposal will result in 100% emissions reduction, replacing used oil for combustion will not result in 100% reduction as burning used oil results in additional emissions). ADEC estimated the cost-effectiveness for Option 1 to be $730,182 per ton of PM and $102,799 per ton of SO_2 emissions reduction.

Option 2: ADEC reached out to commercial vendors and referred to publicly available information from online vendors and the FNSB Solid Waste Division. Based on that information, ADEC found Option 2 to be technologically feasible. In evaluating economic feasibility, ADEC assumed 100% emissions reduction by processing the used oil at the centrifuge facility. Costs to establish a centrifuge facility consisted of building costs, equipment costs (consisting of centrifuge, tankage, and forklift), labor, and operational and maintenance costs. Further, discussions with commercial vendors highlighted that centrifuging used oil (e.g., motor oil, cooking oil, and oil containing animal fat) is a labor-intensive process as the oil must be separated due to the differences in boiling point. ADEC estimated the cost-effectiveness for Option 2 to be $653,989 per ton of PM and $92,072 per ton of SO_2 emissions reduction.

Conclusion

Based on ADEC's additional technological and economic feasibility analysis, ADEC's dismissal of Measure 70 is unchanged from the 2020 Amendments. The combustion of used oil is the only acceptable disposal method available in the FNSB without shipping the used oil to a central facility at Anchorage or processing it at a centrifuge facility in Fairbanks. While ADEC found both options to be partly and fully technologically feasible, the economic analysis resulted in cost-effectiveness numbers that are infeasible. Due to economic infeasibility, ADEC dismisses this measure as BACM in the Fairbanks Nonattainment Area.

Measure R1: Regional Kilns

Implementing Jurisdiction(s)

- None

Regulation Weblink(s)

- http://dec.alaska.gov/air/anpms/comm/docs/fbxSIPpm2-5/Appendix_III.D.5.07_Adopted_12.24.14.pdf

Background

BACM analysis requirements specified in the final $PM_{2.5}$ rule mandate the consideration of "options not previously considered as RACM/RACT for the area". The moderate SIP considered funding the construction of a Regional Kiln to provide a source of dry wood. The RACM analysis determined the measure to be technologically infeasible because of concerns about the demand for dry wood and emissions from fuels used to dry the wood.

EPA commented that this measure should be further evaluated for BACM and MSM.

Analysis

The review of SIP commitments did not identify a single program which mandates the construction of Regional Kilns to provide a source of dry wood. Instead, several programs implemented measures that require the use of dry wood in solid fuel burning devices. Fairbanks implemented a requirement that prohibits burning wood that "has more than 20 percent moisture content" in a solid fuel burning appliance.[286]

A review of the RACM analysis shows that the technologically infeasible determination cited potential adverse environmental impacts due to the increase in regional emissions from kiln-dried firewood compared to air-dried firewood because of the fuel required to operate the kiln. Recently Aurora Energy Solutions, LLC announced plans[287] to install and operate a wood drying kiln in Fairbanks. Operations are expected to start in September 2020 and produce 2,000 cords of dried birch (only) 20% moisture content firewood for the 2020/2021 winter. Heat from a coal-fired cogeneration power plant that Aurora Energy operates in downtown Fairbanks will be used to dry the wood. Details of the design and permitting for the facility are not currently available, but a mixture of waste and production heat are expected to be used to dry the wood. A call[288] to the company found that "firm prices have not been established" for the dried firewood, but will be competitive with the market and in the range of \$350 - \$375/cord delivered and \$425/cord stacked.

Clearly the heat available to Aurora Energy Solutions limits the RACM/BACM concerns about wood drying emissions. While the Aurora wood drying emissions increment is unknown, the modifications required to construct the facility need to satisfy ADEC permitting requirements. Aurora's decision to build the facility is market driven and existing regulations ensure that the facility has no undue environmental impacts. There is, however, no guarantee the Aurora kiln will continue to operate under adverse economic conditions.

Under the Final $PM_{2.5}$ Rule a control measure must result in permanent and enforceable emission reductions. While a regional kiln will introduce a supply of cleaner fuel in the form of dry cordwood, there is no mechanism that guarantees the additional dry wood introduced into the market will offset the use of wet cordwood resulting in emission reductions. While a regional kiln is beneficial to the community and the airshed a regional kiln fails to meet the requirements of permanent and enforceable emission reductions to be considered a control measure.

[286] http://www.codepublishing.com/AK/FairbanksNorthStarBorough/#!/FNSBC21/FNSBC2128.html#21.28.030
[287] https://www.heatyourway.com/our-products
[288] Robert Dulla to Aurora Energy Solutions, LLC staff on 8/13/20

Conclusion

The RACM/BACM analysis concerns are still valid. This control measure is technologically infeasible because it does not require any existing entity to build a kiln, and it does not meet the control measure requirements of permanent and enforceable emission reductions; therefore, it is dismissed from consideration as a control measure for the 2020 Amendment to the Serious SIP.

Measure R7: Ban Use of Hydronic Heaters

Implementing Jurisdiction(s)

- None

Regulation Weblink(s)

https://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-regulations/

Background

BACM analysis requirements specified in the final $PM_{2.5}$ rule mandate the consideration of "options not previously considered as RACM/RACT for the area". The moderate SIP considered banning the use of hydronic heaters. The RACM analysis determined the measure to be technologically infeasible because it did include a provision for homes with no other adequate source of heat. Another consideration was that on very cold days some residences with alternate heat sources find them to be inadequate and need to supplement with heat from wood combustion.

Analysis

The BACM analysis of this control measure is unchanged - the review of SIP commitments did not identify a single program with unrestricted bans on using hydronic heaters. Instead, those programs with curtailments specify the conditions under which curtailments/Air Quality Alerts are called and those programs include a variety of exemptions for homes with NOASH certifications, economic hardship, etc. Fairbanks has implemented a measure mandating Stage 1 and Stage 2 alerts which restrict wood burning when concentrations are forecast to exceed established concentration thresholds (i.e., 20 and 30 $\mu g/m^3$ respectively as of January 8, 2020). Under these conditions use of hydronic heaters are prohibited except under the exemptions specified in the rule.[289]

While a SIP commitment banning outdoor wood boilers (furnaces, etc.) was not identified, several communities in Connecticut (e.g. West Hartford, Hamden, Avon, etc.) were found to have ordinances banning outdoor wood boilers because of nuisance complaints. Commitments to implementing those ordinances, however are not contained in Connecticut's $PM_{2.5}$ SIP.[290]

[289] http://www.codepublishing.com/AK/FairbanksNorthStarBorough/#!/FNSBC21/FNSBC2128.html#21.28.030
[290] http://www.ct.gov/deep/cwp/view.asp?A=2684&Q=419074&depnav_GID=1619

The SIP references a state statute (Section 22a-174k),[291] which restricted the installation of new outdoor wood burning furnaces until EPA issued regulations for hydronic heaters; it also specified setback requirements for new installations. The recent passage of the Fairbanks Home Heating Reclamation Act, required the removal of any solid fuel burning regulations, so again the Borough lacks the authority to curtail wood stove use. The new state regulations implemented in 18 AAC 50.077 and the Episode Chapter of the $PM_{2.5}$ Serious SIP restrict wood-fired heating device operation, but do not ban all operation.

A review of the RACM analysis shows that there are still technologically infeasible elements for this measure, most notable the lack of exemption for those with no other adequate source of heat.

Conclusion

The BACM conclusion is unchanged - this control measure is technologically infeasible due to lack of exemption for those with no other adequate source of heat and is dismissed from consideration as a control measure. for the 2020 Amendment to the Serious SIP

Measure R15: Ban New Installations – Wood Stoves

Implementing Jurisdiction(s)

- None

Regulation Weblink(s)

https://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-regulations/

Background

BACM analysis requirements specified in the final $PM_{2.5}$ rule mandate the consideration of "options not previously considered as RACM/RACT for the area". The moderate SIP considered a measure requiring a ban on new installations of wood stoves. Analysis of the measure was limited:

> *A ban on new installations would not reduce emissions from wood stoves in the near term, but would ultimately reduce emissions as wood stoves were retired; however, this approach could have the negative effect of prolonging the use of existing, dirty units because replacing them with newer, much cleaner units would not be allowed. This measure would not result in quantifiable reductions in the four years after designation.*

Discussion of other wood stove restrictions (e.g., limit the number of new installations allowed in new construction, allow new installations but only if one or more existing stoves were retired first, etc.) was also presented. Ultimately, the RACM analysis determined the measure to be technologically infeasible because it lacked the authority to implement it. That finding was based on a referendum prohibiting the Borough's regulation of home heating which lapsed. The

[291] https://law.justia.com/codes/connecticut/2012/title-22a/chapter-446c/section-22a-174k/

recent passage of the Fairbanks Home Heating Reclamation Act, required the removal of any solid fuel burning regulations, so again the Borough lacks the authority to remove or replace uncertified wood-fired heaters.

Analysis

The BACM analysis for this control measure is unchanged - the state has implemented new regulations that establish strict emission ratings for new heating devices and related installation requirements. Those regulations, however do not prohibit the installation of wood-burning devices. Backup heating systems are essential for survival in an arctic environment as loss of primary heating is not an uncommon occurrence with many causes including: extreme cold temperatures, ice storms, fuel supply loss, etc.

ADEC often hears from FNSB residents who have significant concerns regarding the need for non-electric backup heating systems in their homes. As described in the Emission Inventory, the predominant heating method within the residential space heating sector is residential fuel oil. All fuel oil boilers and heaters require electricity to operate the auxiliary systems such as fans and pumps. Given the subarctic climate and periodic power failures, these individuals have real safety concerns for themselves and their families as well as concerns about damage to their property.

These concerns and expressed needs for reliable backup heat are likely very different in the FNSB nonattainment area than in the lower 48. However, based on the Borough's woodstove changeout/conversion program it is technically feasible to equip a home with adequate backup heating systems that do not rely on solid fuel heating appliances.

Even though it may be technically feasible in certain situations, without widespread availability to natural gas there are limited technologies to provide backup heat to address the safety concerns. While voluntary programs are in place, only 28 emergency power back up systems have been installed through the Borough's program. With the limited number of actual installations, ADEC is cautiously optimistic that the emergency power back up systems will become a proven technology, but at this point the limited installations do not demonstrate that this technology is feasible in every situation. Due to the importance of these systems to ensure citizens safety in an arctic climate, it is not prudent to exclude an entire sector of proven residential heating technology that many citizens rely on for an immediate safety concern.

In order to address new installations ADEC is implementing 18 AAC 50.077 which is discussed in detail under Measure 8.

Conclusion

While this measure is technologically feasible, an economic analysis of its cost effectiveness, presented in Step 4, shows that it is economically infeasible in an arctic environment and therefore not eligible for consideration as a 2020 Amendment Plan control measure.

Measure R17: Ban Use of Wood Stoves

Implementing Jurisdiction(s)

- None

Regulation Weblink(s)

https://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-regulations/

Background

BACM analysis requirements specified in the final $PM_{2.5}$ rule mandate the consideration of "options not previously considered as RACM/RACT for the area." The moderate SIP considered banning the use of wood stoves. The RACM analysis determined the measure to be technologically infeasible because it did not include an exemption for homes with no other adequate source of heat. Another consideration was that on very cold days some residences with alternate heat sources find those sources to be inadequate, and need to supplement with heat from wood combustion.

EPA commented that this measure should be further evaluated for BACM and MSM.

Analysis

The BACM analysis of this control measure is unchanged - the review of SIP commitments did not identify a single program with unrestricted bans on using wood stoves. Instead, those programs with curtailments specify the conditions under which curtailments/Air Quality Alerts are called and those programs include a variety of exemptions for homes with NOASH certifications, economic hardship, etc. Fairbanks has implemented a measure mandating Stage 1 and Stage 2 alerts which restrict wood burning when concentrations are forecast to exceed established concentration thresholds (i.e., currently 20 and 30 $\mu g/m^3$ respectively as of January 8, 2020). Under these conditions use of wood stoves are prohibited except under the exemptions specified in the rule.[292] The recent passage of the Fairbanks Home Heating Reclamation Act, required the removal of any solid fuel burning regulations, so again the Borough lacks the authority to curtail wood stove use. The new state regulations implemented in 18 AAC 50.077 and the Episode Chapter of the $PM_{2.5}$ Serious SIP restrict wood-fired heating device operation, but do not ban all operation.

Conclusion

The BACM conclusion is unchanged - this control measure is technologically infeasible due to lack of exemption for those with no other adequate source of heat and is dismissed from consideration as a control measure for the 2020 Amendment to the Serious SIP.

292 http://www.codepublishing.com/AK/FairbanksNorthStarBorough/#!/FNSBC21/FNSBC2128.html#21.28.030

Measure R20: Transportation Control Measures

Implementing Jurisdiction(s)

- **None**

Regulation Weblink(s)

https://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-moderate-sip/
See Appendix III.D.5.07 Control Strategies (12/24/14)

Background

ADEC in the moderate SIP provided a list of transportation related programs currently being implemented in Fairbanks.

- **Expanded availability of plug-ins; electrical outlets were installed on 1,500+ parking spaces between 2008 & 2015**
- **Ordinance mandating—for employers with 275+ parking spaces—electrification of outlets at temps < 21° F between November 1 and March 31**
- **Public education focused on the benefits of plugging-in and using the transit program called Metropolitan Area Commuter System (MACS)**
- **Expanded transit service includes improved service frequency on high ridership routes, new routes and better bus stop facilities; ridership increased 61% between 2008 & 2013.**
- **Commuter Van Pool program, includes Van Tran program for elderly and disabled**
- **Anti-idling program for heavy-duty diesel vehicles started as a ADOT&PF program focused on dump trucks and tractors and has been expanded to a CMAQ-funded pilot program focused on the purchase and installation of auxiliary heaters to reduce idle time in private fleets.**
- **Federal Motor Vehicle Control Program**

ADEC evaluated several transportation control measures (TCMs), including HOV lanes, traffic flow improvement program, non-motorized traffic zones, employer-sponsored flexible work schedules, retrofit diesel fleet (school buses, transit fleets), on-road vehicle inspection/maintenance (I/M) program, heavy-duty vehicle I/M program, and State LEV program. The analysis of these measures found:

- ***With the exception of the anti-idling program, the programs listed above have been in place for well over a decade and are working to reduce motor vehicle emissions under extreme winter operating conditions.***
- ***Measures focused on reducing traffic congestion offer limited benefits as the Fairbanks road network has few roads operating at Level of Service (LOS) levels D, E, or F.***
- ***Community-wide ridesharing programs offer few potential emission reduction benefits because of the low population and employment density in the nonattainment area (employer programs are operated where sufficient density supports participation).***

- ***Travel reduction programs have been found to have limited benefits on a national basis, with principal reductions coming from commute trips, which require high density employment to be successful.***
- ***EPA's motor vehicle emissions model MOVES, MOVES2014b, does not provide a PM benefit for either light- or heavy-duty I/M programs. Thus, there is no way to quantify a particulate benefit from I/M, and EPA clearly does not recognize I/M as an appropriate PM control measure.***

Based on this evaluation, ADEC did not find any additional TCMs to be viable for Fairbanks and therefore dismissed them based on technological infeasibility.

EPA comments on the moderate SIP findings for this measure were limited to I/M programs and vehicle idle restrictions (which were addressed separately in Measure 60). With regard to I/M, EPA commented that the finding that I/M is technologically infeasible because MOVES2014b does not provide an I/M benefit is not a valid conclusion. They noted that the Utah Cache Valley has an I/M program for VOC and Fairbanks had previously operated an I/M program for carbon monoxide (CO) and this measure needed to be evaluated. EPA's comments on this measure for the serious SIP, not expressed in writing, suggested the need for additional discussion of this measure.

ADEC reevaluated these findings as part of a BACM analysis for the Fairbanks Serious Plan and Fairbanks 189(d) Plan submissions and determined that they had not changed - additional TCMs are technologically infeasible and not eligible for the Fairbanks nonattainment area. ADEC noted that independent studies by NCHRP (a division of the Transportation Research Board) and ASHTO (the American Association of State Highway and Transportation Officials) have documented that while states and communities continue to adopt them, where funding is available, growing experience in lower-48 states has demonstrated emissions benefits are limited. As a result, credit for TCMs in SIPs has diminished and additional TCMs would provide limited emission reduction benefits. With regard to EPA's comment about the need to assess the VOC benefits of an I/M program, the Moderate precursor analysis[293], the Serious SIP and the 2020 Amendments have consistently found that neither VOC nor NOx are significant precursor pollutants in the Fairbanks $PM_{2.5}$ nonattainment area. Thus, ADEC dismissed this measure based on lack of a technical basis to pursue an assessment of the costs and benefits of an I/M program for either VOC or NOx.

ADEC identified the following TCMs and mobile source emission reduction measures: California Air Resources Board (CARB) vehicle standards (Measure 54); school bus retrofits (Measure 55); road paving (Measure 56); controls on road sanding and salting (Measure 58); a vehicle inspection and maintenance (I/M) program (Measure 59); vehicle idling restrictions (Measure 60); and Other TCMs (Measures 57 and R20) including high-occupancy vehicle (HOV) lanes, traffic flow improvements, non-motorized traffic zones; employer-sponsored flexible work schedules, diesel fleet retrofitting (school buses, transit fleets), an on-road vehicle I/M program; a heavy-duty vehicle I/M program, and a low-

[293] ADEC, Serious SIP Development. Accessed at http://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-serious-sip-development.

emission vehicle (LEV) program.[294] ADEC found that none of the identified measures were eligible as BACM for the 2020 Amendments to the Serious SIP.

For Measure 54, ADEC estimated the cost-effectiveness of implementing the LEV III regulations, and determined that the statewide adoption of the CARB emission standards is not cost effective and is not warranted for the Fairbanks $PM_{2.5}$ nonattainment area. EPA in their comments on the 2020 Amendments[295] reviewed ADEC cost effectiveness analysis and determined that it is a reasonable estimate of the cost per ton of pollutant emissions reduced and approved ADEC's dismissal based on economical infeasibilility. ADEC dismissed Measure 55 for two reasons: (1) emissions benefits of the diesel retrofits were unquantifiable, and (2) the school district already has converted diesel school buses to gasoline-powered school buses. EPA evaluated ADEC's basis for rejecting this measure and determined that this measure was appropriately rejected. While EPA did not approve the difficulty in quantifying emissions benefits as a valid basis to reject the measure, EPA accepted that fleet-wide conversion to gasoline-powered buses as equivalent to this BACM requirement. ADEC dismissed Measure 56 as unlike many communities in the lower-48, roads in the Fairbanks nonattainment area remain frozen during winter months and fugitive dust sources of $PM_{2.5}$ are estimated to be negligible under the snow/ice bound conditions reflected in the winter seasonal inventory. EPA accepted ADEC's dismissal of the measure based on technological infeasibility. Similar to Measure 56, ADEC dismissed Measure 58 due to extreme winter weather conditions in Fairbanks Nonattainment Area and EPA approved the ADEC's dismissal on grounds of technological infeasibility.

EPA approved ADEC's rejection of a vehicle I/M program (Measure 59) because such a program only reduces NOx and VOC emissions and the EPA proposed to approve Alaska's precursor demonstration that shows NOx and VOCs are not significant precursors to $PM_{2.5}$ formation in the Fairbanks $PM_{2.5}$ Nonattainment Area. The EPA also proposed to approve Alaska's determination that no NH_3-specific emission controls exist for this source category. However, EPA rejected ADEC's dismissal of Measures 57, 60, and R20, stating ADEC's conclusion lacked a sufficient feasibility assessment.[296] EPA explained that ADEC cannot rely on its determination that the measures would not provide emission reduction benefits because that applies the *de minimis* source category concept inapplicable to $PM_{2.5}$ NAAQS implementation. EPA also stated that none of the ongoing control measures committed to by the State appear to be submitted for SIP approval.[297]

After EPA's disapproval of Measures 57, 60, and R20, ADEC reviewed guidance on the *de minimis* source category concept and the State's currently applicable plans and comments submitted by Fairbanks Area Surface Transportation ("FAST") Planning – the Metropolitan Planning Organization for the urbanized areas of the Fairbanks North Star

[294] Alaska Department of Environmental Conservation, "Amendments to: State Air Quality Control Plan; Vol. III: Appendix III.D.7.7" (November 18, 2020).
[295] 88 Fed. Reg. 1454 (Jan. 10, 2023), at 1481; "Technical support document for Alaska Department of Environmental Conservation's (ADEC) control measure analysis, under 40 CFR 1010(a) and (c)," (Sept. 27, 2022) (hereinafter "Technical Support Document"), at 30-33, 45-46.
[296] 88 Fed. Reg. at 1481; *see also* Technical Support Document Docket No. EPA-R10-AOAR-2022-0115. at 32, 33, 45-46.
[297] 88 Fed. Reg. at 1481; Technical Support Document: Docket No. EPA-R10-AOAR-2022-0115.

Borough, responsible for implementation of TCMs. Finally, ADEC conducted additional technological and economic feasibility evaluations for Measures 57, 60, and R20.

Based on ADEC's analysis, EPA in its Final Rule[298] approved ADEC's analysis and dismissal of Measures 57 and R20 (other TCMs), and proposed to disapprove ADEC's dismissal of Measure 60 (vehicle idling restrictions). Due to the difference in EPA's approvals, Measure 60 is dealt separately and discussed under "Measure 60 – Vehicle Idling Restrictions". EPA accepted ADEC's findings that constructing HOV lanes is technologically infeasible taking into consideration local conditions, including infrastructure, population, and traffic flow. Additionally, EPA concurred with ADEC's determination that traffic flow improvements, diesel retrofits, and ridesharing programs are economically infeasible for the Fairbanks PM2.5 Nonattainment Area, at this time.

Analysis

Following EPA's comments, ADEC reviewed the Final $PM_{2.5}$ Implementation Rule and other relevant EPA guidance, status of the transportation control programs committed to in the Moderate SIP and conducted technological and economic feasibility analysis for Measures 57, 60, and R20.

ADEC demonstrated that it did not rely on the *de minimis* source category concept to dismiss control measures before a BACM analysis was completed. ADEC followed the five-step BACM selection process as defined in the Final $PM_{2.5}$ Rule for selecting measures for the 2020 Amendments to the Serious SIP.[299] At Step One, ADEC assembled an inventory of source and source categories, including mobile sources. At Step Two, ADEC identified candidate control measures that are more stringent than those adopted in the Serious Area SIP. ADEC identified these control measures after reviewing options not previously considered as BACM, control measures implemented in other nonattainment areas, and measures considered by regional planning organizations and state and local air quality consortiums. At Step Three, ADEC analyzed the technological feasibility of the identified control measures with a key consideration to ensure the identified measure is the most stringent and provides a quantifiable emissions benefit beyond those provided by existing federal, state, and local controls.[300]

For Measures 57 and R20, relating to transportation control measures, ADEC determined that relevant findings regarding local conditions from the Moderate and Serious SIP submissions have not changed and continued to support a conclusion that TCMs would not provide additional emission reductions and therefore are technologically infeasible. ADEC also provided a reasoned, narrative explanation with qualitative supporting documentation justifying its dismissal. The process followed by ADEC is according to the process outlined in the $PM_{2.5}$ Final Rule and demonstrates that ADEC did not rely on the fundamentally inapplicable *de minimis* source category concept and instead, ADEC sufficiently

[298] 88 Fed. Reg. at 84626.
[299] Alaska Department of Environmental Conservation, "Amendments to: State Air Quality Control Plan; Vol. III: Appendix III.D.7.7" (November 18, 2020).
[300] 40 C.F.R. § 51.1010(a)(3)(iii)

demonstrated that Measures 57, 60, and R20 are technologically infeasible as required for its BACM analysis.

In response to EPA's that none of the existing transportation programs have been submitted for SIP approval, ADEC demonstrated that all of the ongoing transportation programs were included in the approved Moderate SIP and are TCMs for conformity purposes,[301] and the Moderate SIP is the applicable plan for satisfying the requirements for timely implementation of TCMs under 40 CFR 93.113 and was approved by EPA on September 8, 2017.[302] The approved measures included: Fairbanks North Star Borough Ordinance No. 2001-17 that requires employers or businesses that have 275 or more parking spaces to provide power to electrical outlets at temperatures of 20 degrees F or lower for engine block heaters; expanded availability of plug-ins; public education focused on the benefits of plugging-in and using the transit program; expanded transit service; commuter van pool program; anti-idling program for heavy-duty diesel vehicles focused on the purchase and installation of auxiliary heaters to reduce idle time; and the Federal motor vehicle control program. As required by 40 CFR 51.1005(b)(1)(ii), ADEC demonstrated in the 2020 Amendments to the Serious SIP that all transportation programs submitted in the Moderate SIP have been implemented and, even for those projects that have been completed, continue to provide ongoing emission reduction benefits.[303]

ADEC evaluated feasibility analysis including a technological feasibility assessment for HOV lanes, and an economic feasibility assessment for HOV lanes, traffic flow improvements, diesel retrofit projects, and ridesharing programs. For HOV lanes, ADEC performed a quantitative worst-case analysis of freeway volumes assuming peak hour volumes, and highway capacity for a limited freeway road where HOV lanes are practical.[304] Among the freeways within the Nonattainment Area that fit these criteria, ADEC selected the Steese Expressway at the Chena River Bridge just east of downtown Fairbanks that was found to exhibit the highest peak hour traffic volumes based on a review of traffic counts from January 1, 2022, through March 18, 2023. ADEC found that even with conservative assumptions, the Steese Expressway would experience reasonably free-flow operations and free-flow speeds. Based on these findings, ADEC concluded that construction of HOV lanes for Steese Expressway or similar four-lane divided highways would provide no emissions reduction and therefore are technologically infeasible. In addition to ADEC's analysis, FAST planning provided additional information supporting ADEC's determination that HOV lanes would be technologically infeasible as BACM given local conditions. In their comment letter dated February 15, 2023, FAST Planning highlights that HOV lanes "are generally intended for communities with a regional population over 1.5 million people that experience severe congestion with motorists trying

[301] 40 CFR 93.101

[302] Federal Register. 82 FR 42457. Accessed at https://www.govinfo.gov/content/pkg/FR-2017-09-08/pdf/2017-17824.pdf#page=3.

[303] Alaska Department of Environmental Conservation, "Amendments to: State Air Quality Control Plan; Vol. III: III.D.7.7, Control Strategies" (November 18, 2020).

[304] Roadways with lengths of several miles or more to enable vehicle to move into and out of the HOV lane from the other mixed-use lanes.

to access major employment centers/business districts."[305] Fairbanks urban population is 70,000, and as a result does not have the congestion that would warrant even a remote need for such lanes.

ADEC evaluated the economic feasibility based on the cost-effectiveness estimates from a comprehensive study published by the Federal Highway Administration ("FHWA") for Congestion Mitigation and Air Quality ("CMAQ") Improvement Program eligible projects in 2020 and local specific information specific to the Nonattainment Area.[306] The CMAQ program provides funding to state and local governments to fund transportation projects and programs to help meet CAA requirements. State and local governments select candidate projects for funding based on the cost-effectiveness metrics for a range of pollutants. The study uses EPA's MOVES2014b model combined with project-level impacts (e.g., VMT impacts, travel speeds) to identify emission impacts by criteria pollutant and applicable precursors. The range of project types included in the analysis is targeted at representing an informative view of the relative performance of predominant project types around the country across a range of pollutants eligible for CMAQ funding.

Traffic flow improvements projects correspond to traffic signal improvements and synchronization, roundabouts, and intersection improvement that resulted in a reduction in delay and improvements in the level of service. For signal synchronization, the FHWA study evaluated several projects considering different land use, annual average daily travel (AADT) ranging between 20,000 to 75,000, and project costs between $500,000 to $2.9M. The study estimated the median cost-effectiveness estimates to be $1,136,071 per ton of $PM_{2.5}$ reduced. For roundabouts, the analysis was based on several alignments with an AADT of 5,000 to 32,000 vehicles and project costs ranging between $250,000 to $2.6M. The study estimated the median cost-effectiveness to be $1,091,411 per ton of $PM_{2.5}$ reduced. For intersection improvements, the analysis was based on several urban and rural intersection designs, with an AADT ranging between 5,000 to 40,000, and project costs between $400,000 to $2.8M. The study found the median cost-effectiveness to be $13,255,774 per ton of $PM_{2.5}$ reduced.

Diesel retrofit projects consisted of retrofitting older diesel vehicle engines with emissions reduction technologies such as diesel particulate filters ("DPF"), Selective Catalytic Reduction ("SCR"), Diesel Oxidization Catalysts ("DOC"), and Exhaust Gas Recirculation ("EGR") technologies. Based on an annual representative vehicle miles traveled estimate of 11,492 and retrofitted device costs ranging from $750 - $18,000, the study estimated the median cost-effectiveness to be $165,130 per ton of $PM_{2.5}$ reduced.

Ridesharing projects encourage mode shift from single-occupant LDVs to multiple-occupant vehicles and cater to different purposes such as marketing and outreach, operation assistance, pooling of low-emission vehicles, and vanpool startup and

[305] FAST Planning Comment Letter at 3 (additionally citing a 2021 FHWA inventory indicating that there are only 18 states with HOV lanes, all of which serve major population centers).
[306] Federal Highway Administration, "Congestion Mitigation and Air Quality Improvement (CMAQ) Program, 2020 Cost-Effectiveness Tables Update," (hereinafter "FHWA 2020 CE Tables"). Accessed at https://www.fhwa.dot.gov/ENVIRonment/air_quality/cmaq/reference/cost_effectiveness_tables/fhwahep20039.pdf.

replacement. The analysis evaluated several scenarios with an average cost of $400,000 and assumed the average reduction in single-occupant trips associated with each rideshare trip as eight (i.e., half of a van's capacity) and the average round-trip distance associated with mitigated single-occupant trips as 240 miles. The study estimated the median cost-effectiveness to be $6,010,024 per ton of $PM_{2.5}$ reduced.

ADEC evaluated the key input parameters (emission rates, traffic, and project costs) utilized by FHWA in developing their cost-effectiveness estimates against the local conditions in Fairbanks. The FHWA estimates are based on the MOVES2014b model while the latest model at the time of ADEC's comments was MOVES3.0.4. Compared to the MOVES2014b version, MOVES3.0.4 produced 26% less NOx emissions and 57% less $PM_{2.5}$ emissions. [307,308] **The traffic estimates that FHWA used in developing CE numbers are higher than the local traffic conditions reflected in Fairbanks. ADEC based on their evaluation of traffic improvement project nominations submitted to FAST Planning for the CMAQ-funding program found the traffic estimates in Fairbanks to align with the lower end of the traffic ranges assumed in the FHWA report (around 5,000) for traffic flow improvement projects. The construction costs used in developing the cost estimates are much lower than what can be expected in Fairbanks due to the shorter construction season when the ground is thawed, soil conditions suitable for construction, high freight charges to ship materials from lower-48 states to Alaska, and limited prime contractors in the area who are qualified to do road work. Combination of lower emission rates from the latest MOVES3 model, lower annual average daily traffic, and higher construction costs in Fairbanks would result in lower emissions and higher costs resulting in higher cost-effectiveness numbers than what is estimated in the FHWA report. The projected cost-effectiveness estimates after accounting for the local conditions in Fairbanks, for the project types accounted for by Measures 57, and R20 are economically infeasible in the Nonattainment Area.**

In the Final Rule[309]**, EPA received no comments regarding its proposed approval of Alaska's rejection of the CARB vehicle standards (Measure 54), school bus retrofits (Measure 55), road paving (Measure 56); controls on road sanding and salting (Measure 58); and Vehicle I/M program (Measure 59) as either technologically or economically infeasible. EPA noted that the supplemental feasibility analysis provided by ADEC addressed EPA's concern about not rejecting the control measures based on the de minimis criteria. EPA concurred that it had previously approved the Moderate Plan, including RACM for the mobile source category. EPA noted that RACM does not meet the CAA's BACM requirements, and although ADEC identified additional measures, they did not evaluate the feasibility of these measures and EPA proposed to disapprove the TCMs in the Serious Plan and 2020 Amendments. However, EPA found the updated supplemental analysis submitted by ADEC in response to EPA's comments evaluating the technological**

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[307] FAST Planning, "2045 Metropolitan Transportation Plan," at 31; *see also id.* at Appendix D, D-24.
[308] This evaluation was conducted by the FAST planning as part of their 2045 Metropolitan Transportation Plan ("MTP") Regional Emissions Analysis and Air Quality Conformity. The analysis consisted of evaluating both models for 2022 for the Fairbanks nonattainment area for same set of inputs.
[309] 88 Fed. Reg. at 84626.

and economic feasibility of measures to be valid and concurred with ADEC's dismissal of Measures 57, and R20.

Conclusion
In the Serious SIP and the 2020 Amendments, ADEC identified several transportation control and mobile source emission reduction measures (Measures 54, 55, 56, 57, 58, 59, 60, R20) and evaluated their feasibility as a BACM. EPA in their comments on the 2020 Amendments approved ADEC's dismissal of Measure 54 based on economic feasibility and Measures 55, 56, 58, and 59 based on technological infeasibility.

However, EPA rejected ADEC's dismissal of Measures 57, 60, and R20, in response to which ADEC provided justification and conducted additional feasibility evaluation. ADEC's dismissal of Measures 57, and R20 remain unchanged from the Serious Plan and the 2020 Amendments. These TCMs relate to the HOV lanes, traffic flow improvements, retrofit diesel program, and ridesharing programs. ADEC based this on its technological feasibility determination consistent with applicable law and EPA guidance, and economical feasibility analysis based on supporting information available from FHWA's cost-effectiveness analysis and the case-specific circumstances applicable to Fairbanks. Further, the existing TCMs are being implemented pursuant to the applicable Moderate SIP and reflect ongoing commitments that result in emission benefits.

Based on ADEC's analysis, EPA in its Final Rule approved ADEC's analysis and dismissal of Measures 57 and R20. EPA, however, disapproved ADEC's dismissal of Measure 60 related to vehicle idling restrictions for light-duty vehicles but approved the vehicle idling restrictions for heavy-duty vehicles. Anti-idling restrictions are described in detail under Measure 60.

Measure R29: Increase Coverage of the District Heating System

Implementing Jurisdiction(s)

- Fairbanks North Star Borough

Regulation Weblink(s)

- None

Background

Many residential, commercial, and institutional buildings within downtown Fairbanks are connected to a district heating system that supplies low pressure steam or hot water for space heating and domestic hot water use. Use of the district heating systems allows for the widespread use of energy produced by a central steam generating unit with effective emissions controls. These systems essentially eliminate the need for the operation of individual fuel combustion heating units in each of the facilities receiving heat from a central plant.

Even considering transmission losses, a well maintained and operated central heating facility can be much more efficient than individual combustion units, especially those that burn wood, coal, or oil. Emissions from a central facility are released into the atmosphere at a much greater height above grade than those of combustion units in individual buildings and, as a result, disperse more widely.

Aurora Energy operates a coal-fired cogeneration power plant that recycles low pressure steam for district heating use. Aurora Energy provides district heating (in the form of low-pressure steam or hot water) to approximately 180 customers. Customers range in size from small residential to large commercial/institutional loads.

Analysis

Aurora commissioned a study[310] in 2008 to examine the feasibility of expanding the underground network of pipes that deliver steam and hot water. Based on the information presented in that study, the RACM analysis determined this measure to be technologically feasible. Aurora provided updated heating expansion cost information in 2018.[311]

Conclusion

No information has become available to change the RACM analysis conclusion about the technological feasibility of this measure; therefore, this measure is technologically feasible and eligible for consideration as a control measure for the 2020 Amendment to the Serious SIP. The results of a cost effectiveness analysis of this measure, presented in Step 4, show this measure is economically infeasible.

[310] PDC, Inc. Engineers, *Aurora Energy District Heat Capacity Study, Phase 2*, December 2008
[311] Email from Matt Burdick, PE, Project Engineer, Aurora Energy to Bob Dulla, Trinity Consultants, October 12, 2018

5. Step 4 – Determine Whether an Available Control Technology or Measure is Economically Feasible

EPA guidance[312] on determining the economic feasibility of technically feasible control measures was followed to calculate the cost per ton of pollutant reduced. Key cost information collected to support the preparation of the $/ton calculation included:

- Material/equipment prices (local purchase price, etc.)
- Labor (inspection, installation, maintenance, etc.)
- Program costs associated with implementing new control measures (including staff, software development, overhead, etc.)
- Maintenance costs (local labor and parts)
- Connection fees as appropriate (e.g., trenching, parts, etc.)
- Useful life – ranged between 8 and 30 years depending on the device lifespan
- Capital recovery rate – assumed to be 5.5%
- Existing fuel prices (documented by the Fairbanks Community Planning Department)
- Distillate fuel price forecasts (using EIA Pacific Region forecasts)
- Impact of market shifts on home heating fuel supply costs contained in the Appendix to Chapter 7
- Energy content of heating fuels (based on fuel sold in the Borough and reported by local suppliers)
- Combustion efficiency changes associated with the implementation of selected control measures
- Changes in home heating activity associated with measures addressing curtailment
- Changes in NOASH permits
- Changes in heating systems incorporated into new homes

The above information was used to calculate the annualized cost of operating current heating devices and the annualized cost of implementing individual measures for those devices consistent with the assumptions employed in the 2020 emissions inventory. A summary of the cost per ton of $PM_{2.5}$ reduced for each of the technically feasible measures in the 2024 Amendment is presented below in Table 11. The results indicate all of the measures are not cost effective and have not been selected for implementation.

[312] Federal Register/Vol. 81, No. 164, August, 24, 2016, page 55805

Table 11. Assessment of Economic Feasibility for Technically Feasible Control Measures (Cost Effectiveness Estimate)

Measure #	Measure Description	$/ton of $PM_{2.5}$ Reduced
57.	Other transportation Control Measures*	>1,000,000
60.	Vehicle Ilding for Light-duty Vehicles	>1,000,000
60.	Vehicle Ilding for Heavy-duty Vehicles	455,676
68.	Charbroilers	40,343 to 568,610
70.	Used Oil Burners	653,989 to 730,182
Measure #	**Measure Description**	**$/ton of SO_2 Reduced**
70.	Used Oil Burners	92,072 to102,799
Measure #	**Measure Description**	**$/ton of Combined $PM_{2.5}$ and SO_2 Reduced**
51b.	No. 2 to ULS home heating oil	58,252 to 73,816

** Other transportation Control Measures consists of HOV lanes, traffic flow improvements, diesel retrofit projects, and ridesharing programs. ADEC dismissed implementation of HOV lanes based on technological infeasibility and evaluated the remaining TCMs for economic feasibility.*

The above estimates of Measure 51 cost-effectiveness reflect the following revisions from the 2020 Amendment:

- Correction of Episodic to Annual Energy Use factors
- Correction of Adjusted Energy Use Error
- Consideration of Combined SO_2 and $PM_{2.5}$ Cost Effectiveness
- Correction of Fuel Use Impacts from Reduced Boiler Fouling
- Incorporation of Local Oil Appliance Survey Data
- Impacts of Changes in Heating Oil Market Prices
- Impacts of Relative vs. Additive ULSD Price Increases
- Impacts of Changes in Baseline Heating Oil Sulfur Content

The revisions to these assumptions and related documentation are incorporated into the attached cost effectiveness spreadsheets. The results show that direct $PM_{2.5}$ emissions would increase with any price increase to heating oil because of increase in wood use due to the well-established wood/oil cross-price elasticity. The $PM_{2.5}$ increase from higher-priced ULSD necessitated consideration of cost-effectiveness not just for SO_2, but $PM_{2.5}$ as well. $PM_{2.5}$ increases result in negative cost-effectiveness when considered individually. This negative $PM_{2.5}$ cost-effectiveness is not the result of economic savings, but the $PM_{2.5}$ emission increase. Thus, the revision weighed the emission impacts of ULSD on both SO_2 and $PM_{2.5}$, to reflect their relative impact on ambient $PM_{2.5}$ formation in Fairbanks. Alaska adopted and implemented 18 AAC 50.078(b) that required the use of #1 fuel oil in Fairbanks starting September 1, 2022, which reduced the sulfur content in heating oil by over 50%. ADEC made a total of eight distinct revisions to the economic analysis and evaluated several scenarios to estimate ULSD cost-effectiveness going forward from what is now the current heating oil, #1 fuel oil. The calculated cost-effectiveness under these scenarios was significantly higher than all others evaluated, illustrating the extreme non-linear increases in both costs and emission impacts to further reduce Fairbanks heating oil sulfur content to 15 ppm ULSD. The range presented in the combined cost-effectiveness reflects the uncertain future price and supply impacts.

6. Step 5 – Determine the Earliest Date by Which a Control Measure or Technology can be Implemented in Whole or in Part

The Step 3 technological feasibility analysis identified 5 measures for Step 4 economic feasibility analysis. The Step 4 analysis found no measure for implementation based on high cost-effectiveness estimates. The only measure that ADEC evaluated at Step 5 is Measure 64 related to implementing building codes as part of weatherization. Although ADEC dismissed this measure based on technological infeasibility, implementing building codes will exceed the timeline to implement the control measure as per the regulatory guidelines.

7. BACM Findings

The analysis for the 2024 Revised Amendment to the Serious SIP considered 11 separate control measures. The disposition of those measures is as follows:

- Measure 31 – ADEC is revising regulation from the 2020 Amendment based on EPA's comments.
- Measure 32 – ADEC is revising regulation from the 2020 Amendment based on EPA's comments.
- Measure 48 – ADEC is revising regulation from the 2020 Amendment based on EPA's comments.
- Measure 49 – ADEC is revising regulation from the 2020 Amendment based on EPA's comments.
- Measure 51 – ADEC is dismissing this measure based on technological and economic infeasibility.
- Measure 57, R20 – ADEC is dismissing this measure based on technological infeasibility for HOV lanes and economical infeasibility for traffic flow improvements, diesel retrofit, and ridesharing programs.
- Measure 60 – ADEC is dismissing this measure based on technological and economic infeasibility.
- Measure 64 – ADEC is committing to have a robust public education and outreach and is developing a new regulation for energy rating program required by homeowners at the time of real estate transaction. ADEC is dismissing implementing building codes based on technological infeasibility and timeframe implementation issues.
- Measure 67 – ADEC is revising regulation from the 2020 Amendment based on EPA's comments.
- Measure 68 – ADEC is dismissing this measure based on technological and economic infeasibility.
- Measure 70 – ADEC is dismissing this measure based on economic infeasibility.

ADEC is revising/developing regulations for 6 measures in the 2024 Amendment to the Serious SIP. These measures will reduce $PM_{2.5}$ and SO_2 emissions and aid community/state efforts to achieve attainment of the ambient 24-hour $PM_{2.5}$ standard.

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Appendices

Cost-effectiveness Calculation Spreadsheets are included for the following control measures:

- Measure 51: Ultra-low Sulfur Heating Oil
- Measure 60: Vehicle Idling Restrictions for (A) Heavy-duty Vehicles, and (B) Light-duty Vehicles.
- Measure 68: Charbroilers
- Measure 70: Used Oil Burners

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Chena Power Plant BACT Appendix Documents

Contents

The following spreadsheets are included as part of the appendix. However, due to their electronic nature, they may be found posted separately on the web page:

1. 02.23.24 Statistical Analysis for PM2.5 Emission Limit from 2011 Source Test.xlsx
2. 31430_Aurora_DSI_Opinion_of_Probable_Cost_F.xlsx
3. AppxA&B_CPP-BACT_Tables_2024125.xlsx
4. 0327.24 Department DSI Cost Calculation.xlsx
5. 1009.23 Aurora Rail Samples for Coal.xlsx
6. 10.10.23 ADEC preliminary Estimate of Increased Load on Chena Power Plant Baghouse.xlsx

ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION
Air Permits Program

BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION ADDENDUM
for
Chena Power Plant
Aurora Energy, LLC.

Prepared by: Dave Jones
Reviewed by: Moses Coss
Final Date: October 21, 2024

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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

Chena Power Plant is a stationary source owned by Aurora Energy, LLC (Aurora) which consists of four boilers. Emission Units (EUs) 4 through 6, also identified as Chena 1, 2, and 3, are coal-fired overfeed traveling grate stokers with a maximum steam production rating of 50,000 lbs/hr each. Maximum design power production is 5 megawatts (MW) each. EU 4 was installed in 1954, while EUs 5 and 6 were installed in 1952. EU 7, also identified as Chena 5, is a coal-fired, spreader stoker boiler with a maximum steam production rating of 200,000 lbs/hr and maximum power production rating of 20 MW. Chena 5 was installed in 1970. Maximum coal consumption is 284,557 tons of coal per year, based on the capacities of EUs 4 through 7. Coal receiving and storage (handling) facilities are located on the north bank of the Chena River, and consist of a rail car receiving station, enclosed coal crusher (receiving building), open storage piles, conveyors, and elevators. Coal is transported by conveyors over the Chena River to the Chena Power Plant, located just above the south bank. In the late 1980's, the coal handling system was renovated.

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 for $PM_{2.5}$ and its precursors in support of the state agency's required SIP submittal once the nonattainment area is re-classified as a Serious $PM_{2.5}$ nonattainment area. The designation of the area as "Serious" with regard to nonattainment of the 2006 24-hour $PM_{2.5}$ ambient air quality standards was published in Federal Register Vol. 82, No. 89, May 10, 2017, pages 21703-21706, with an effective date of June 9, 2017. [1]

The initial BACT Determination for Aurora was included in Part 5 of Appendix III.D.7.07 Control Strategies Chapter, in the State Air Quality Control Plan adopted on November 19, 2019, with amendments adopted on November 18, 2020, as part of a complete SIP package.[2] The *EPA's Air Plan Partial Approval and Partial Disapproval; AK, Fairbanks North Star Borough; 2006 24-hour $PM_{2.5}$ Serious Area and 189(d) Plan*[3] published in the Federal Register on December 5, 2023 (*88 Fed. Reg. 84654*) disapproved of Alaska's initial BACT determination for SO_2 controls and lack of determination for $PM_{2.5}$ controls.

This BACT Determination Addendum applies to the significant emissions units (EUs) listed in Operating Permit No. AQ0315TVP04 Revision 2 and establishes limits for $PM_{2.5}$ and SO_2air emissions with corresponding monitoring, recordkeeping and reporting requirements to ensure continuous compliance with such limits. This BACT Determination Addendum complements the Department's previous November 18, 2020 SIP adoption in response to EPA's comments listed

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

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

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

in Memorandum dated August 24, 2022 from Zach Hedgpeth, R10/LSASD/ECB and Larry Sorrels OAQPS/HEID/AEG to Matthew Jentgen, ARD.[4]

This BACT Determination Addendum provides the Department's review of the BACT analysis for $PM_{2.5}$, and the BACT analysis for sulfur dioxide (SO_2) emissions, which is a precursor pollutant that can form $PM_{2.5}$ in the atmosphere post combustion.

Since the SIP amendments adopted on November 18, 2020, the Department conducted extensive modeling and found that SO_2 emissions from stationary sources do not significantly contribute to ground level $PM_{2.5}$ concentrations, and that BACT emission limits are therefore not required for major stationary sources in the Fairbanks North Star Borough. BACT determinations have, however, been included in this BACT Determination Addendum since an SO_2 precursor demonstration has not yet been approved by EPA.

Notwithstanding the SO_2 precursor demonstration mentioned above, this Addendum, does not address BACT to control oxides of nitrogen (NOx) emissions, which is also a precursor pollutant that can form $PM_{2.5}$ in the atmosphere post combustion, because the EPA has approved[3] of the Department's comprehensive NOx precursor demonstration under 40 C.F.R. 51.1006(a)(1) and 51.1010(a)(2)(ii).

2. BACT EVALUATION

A BACT analysis is an evaluation of all available control options for equipment emitting the triggered pollutants and a process for selecting the best option based on technical 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 significant EUs at the Chena Power Plant that emit $PM_{2.5}$ and SO_2, establish emission limits which represent BACT, and assess the level of monitoring, recordkeeping, and reporting (MR&Rs) necessary to ensure Chena Power Plant applies BACT for the EUs on a continuous basis. The Department based the BACT review on the five-step, top-down approach set forth in Federal Register Volume 61, Number 142, July 23, 1996 (Environmental Protection Agency).

Table A presents the significant EUs subject to BACT review.

Table A: Emission Units Subject to BACT Review

EU	Emission Unit Name	Emission Unit Description	Rating/Size	Installation or Construction Date
1	Coal Preparation Plant	Exhaust and Fugitive Emissions	75 tons/hr	1950[1]
2	Coal Stockpile	Fugitive Emissions	0.59 acre	1950[2]
3	Ash Vacuum Pump Exhaust	Ash System Baghouse Exhaust	24,187 tons ash/yr	1997
4	Chena 1 Coal Fired Boiler	Full Stream Baghouse Exhaust	76 MMBtu/hr	1954

[4] Document 000006_EPA Technical Support Document – Aurora BACT TSD v20220824: https://www.regulations.gov/document/EPA-R10-OAR-2022-0115-0212.

5	Chena 2 Coal Fired Boiler	Full Stream Baghouse Exhaust	76 MMBtu/hr	1952
6	Chena 3 Coal Fired Boiler	Full Stream Baghouse Exhaust	76 MMBtu/hr	1952
7	Chena 5 Coal Fired Boiler	Full Stream Baghouse Exhaust	269 MMBtu/hr	1970
8	Truck Bay Ash Loadout	Bottom of Silo – Fugitive Emissions	N/A	1952

Table Notes

1. EU ID 1 was modified in 1990.
2. EU ID 2 was modified in 2013.

Five-Step BACT Determinations

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

Step 1 Identify All Potentially Available Control Technologies

The Department identifies all available control technologies for the EUs and the pollutant under consideration. This includes technologies used throughout the world or emission reductions through the application of available control techniques, changes in process design, and/or operational limitations. To assist in identifying available controls, the Department reviews available 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. It is usually the first stop for BACT research. In addition to the RBLC search, the Department used several search engines to look for emerging and tried technologies used to control $PM_{2.5}$ and SO_2 emissions from equipment similar to those listed in Table A. Aurora has also identified and proposed multiple pollution control technologies.

Step 2 Eliminate Technically Infeasible Control Technologies

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

Step 3 Rank the Remaining Control Technologies by Control Effectiveness

The Department ranks the remaining control technologies in order of control effectiveness with the most effective at the top.

Step 4 Evaluate the Most Effective Controls and Document the Results as Necessary

The Department reviews the detailed information in the BACT analysis about the control efficiency, emission rate, emission reduction, cost, environmental, and energy impacts for each technology 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 and 4 present the Department's BACT Determinations for $PM_{2.5}$ and SO_2.

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

3. BACT DETERMINATION FOR NOx

Through this BACT Determination Addendum, the Department removes the NOx BACT determinations and related requirements adopted on November 19, 2019, with amendments adopted on November 18, 2020,[2] for the Chena Power Plant in their entirety. This is due EPA's approval of the Department's precursor demonstration that NOx emitted from the stationary source does not significantly contribute to ground level concentrations of $PM_{2.5}$ formation. The Department prepared a comprehensive precursor demonstration (as allowed under 40 C.F.R. 51.1006(1) and 51.1010(a)(2)(ii)).

The $PM_{2.5}$ NAAQS Final SIP Requirements Rule states if the state determines through a precursor demonstration that additional emission controls for a precursor gas are not needed for attaining the standard, then the controls identified as BACT/BACM or Most Stringent Measure for the precursor gas are not required to be implemented.[5] The Department's NOx precursor demonstration was approved in *EPA's Air Plan Partial Approval and Partial Disapproval; AK, Fairbanks North Star Borough; 2006 24-hour $PM_{2.5}$ Serious Area and 189(d) Plan*[3] published in the Federal Register on December 5, 2023 (*88 Fed. Reg. 84654*).

For additional details, see the precursor demonstration for NOx in the Serious SIP Modeling Chapter III.D.7.8.[2]

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.

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

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 the 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,[6] pulse-jet,[7] and reverse-air.[8] Fabric filter systems have control efficiencies of 95% to 99.9%, and are generally specified to meet a discharge concentration of filterable particulate (e.g., 0.01 grains per dry standard cubic feet). The Department considers fabric filters a technically feasible control technology for the industrial coal-fired boilers.

(b) Wet and Dry Electrostatic Precipitators (ESP)

ESPs remove particles from a gas stream by electrically charging particles with a discharge electrode in the gas path and then collecting the charged particles on grounded plates. The inlet air is quenched with water on a wet ESP to saturate the gas stream and ensure a wetted surface on the collection plate. This wetted surface along with a period deluge of water is what cleans the collection plate surface. Wet ESPs typically control streams with inlet grain loading values of 0.5 – 5 gr/ft^3 and have control efficiencies between 90% and 99.9%.[9] Wet ESPs have the advantage of controlling some amount of

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

condensable particulate matter. The collection plates in a dry ESP are periodically cleaned by a rapper or hammer that sends a shock wave that knocks the collected particulate off the plate. Dry ESPs typically control streams with inlet grain loading values of 0.5 – 5 gr/ft^3 and have control efficiencies between 99% and 99.9%.[10] The Department considers ESP a technically feasible control technology for the industrial coal-fired boilers.

(c) Wet Scrubbers
Wet scrubbers use a scrubbing solution to remove $PM/PM_{10}/PM_{2.5}$ from exhaust gas streams. The mechanism for particulate collection is impaction and interception by water droplets. Wet scrubbers are configured as counter-flow, cross-flow, or concurrent flow, but typically employ counter-flow where the scrubbing fluid is in the opposite direction as the gas flow. Wet scrubbers have control efficiencies of 50% - 99%.[11] One advantage of wet scrubbers is that they can be effective on condensable particulate matter. A disadvantage of wet scrubbers is that they consume water and produce water and sludge. For fine particulate control, a venturi scrubber can be used, but typical loadings for such a scrubber are 0.1-50 grains/scf. The Department considers the use of wet scrubbers a technically feasible control technology for the industrial coal-fired boilers.

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

(e) Settling Chamber
Settling chambers appear only in the biomass fired boiler RBLC inventory for particulate control, not in the coal fired boiler RBLC inventory. This type of technology is a part of the group of air pollution control collectively referred to as "pre-cleaners" because the units are often used to reduce the inlet loading of particulate matter to downstream

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

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

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

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

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

Step 4 - Evaluate the Most Effective Controls proposed by Aurora Energy, LLC
Aurora has not proposed BACT limits for $PM_{2.5}$ for the Chena Power Plant.

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 EUs 4 through 7 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 EUs 4 through 7 shall be controlled by maintaining good combustion practices at all times the units are in operation;

(c) $PM_{2.5}$ emissions from EUs 4 through 7 shall not exceed 0.045 lb/MMBtu[12] averaged over a 3-hour period;

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

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

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

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

Table 4-2. Comparison of $PM_{2.5}$ BACT for Coal-Fired Boilers at Nearby Power Plants

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

4.2 $PM_{2.5}$ BACT for 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 4-3.

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

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

RBLC Review

A review of similar units in the RBLC indicates good operational practices, enclosures, fabric

Source test data from the Chena Power Plant supports the chosen emission limit. From a 11/19/2011 source test on the common stack at the Chena Power Plant, the average source test result reported was 0.0272 lb/MMBtu, with emission results from each run ranging from 0.0211 to 0.0388 lb/MMBtu. The evaluation of an adequate emission factor requires consideration of statistical variability when limited empirical data exists. Using the results of the 3 source test runs conducted and applying a confidence level of 95% using a two-tailed t-distribution, this emission factor at the upper range would be 0.048 lb/MMBtu.

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

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 Technologies for Material Handling
From research, the Department identified the following technologies as available for control of $PM_{2.5}$ emissions from material handling:

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

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

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

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

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

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

(g) Wind Screens
A wind screen is similar to a solid fence which is used to lower wind velocities near stockpiles and material handling sites. As wind speeds increase, so do the fugitive emissions from the stockpiles, conveyors, and transfer points. The use of wind screens is appropriate for materials not already located in enclosures. The material handling units with the exception of the coal storage pile are operated in enclosures. Therefore, the

Department does not consider wind screens a technically feasible control technology for the other 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 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
Aurora has not proposed BACT limits for $PM_{2.5}$ for Material Handling.

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 EU 1 will be controlled by a partial enclosure;

(b) $PM_{2.5}$ emissions from EUs 3 and 8 will be controlled by a full enclosure;

(c) $PM_{2.5}$ emissions from the ash vacuum pump exhaust EU 3, will be controlled by installing, operating, and maintaining fabric filters;

(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; and

(e) Comply with the numerical emission limits listed in Table 4-4:

Table 4-4. $PM_{2.5}$ BACT Control Technologies for the Material Handling Units

EU ID	Process Description	Capacity	Limitation		Control Method
1	Coal Preparation Plant	75 tons/hr	0.34	tpy	Partial Enclosure & Fugitive Dust Control Plan
2	Coal Stockpile	0.59 acre	0.14	tpy	Fugitive Dust Control Plan
3	Ash Vacuum Pump Exhaust	24,187 tons ash/yr	0.24	tpy	Fabric Filter, Enclosure, & Fugitive Dust Control Plan
8	Truck Bay Ash Loadout	N/A	0.0004	tpy	Enclosure and Fugitive Dust Control Plan

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 Aurora for the Chena Power Plant, US Army for Fort Wainwright, and UAF for the Combined Heat and Power Plant.

On December 5, 2023, EPA published a final rule approving in part and disapproving in part DEC's Serious PM2.5 SIP. ADEC withdrew the SO_2 BACT determinations for the stationary sources, including the Chena Power Plant, in a letter to EPA Region 10 dated September 25, 2023. In the preamble to the final rule, EPA references the withdrawal of the SO2 BACT determinations from the Serious PM2.5 SIP and states that because the Serious SIP does not identify, adopt, or implement BACT for SO_2, EPA has finalized partial disapproval of the SIP. Prior to the final disapproval, the EPA reviewed the BACT analysis from the major sources and has also independently performed their own cost effectiveness calculations and collected information from suppliers of DSI equipment and sorbent. These efforts have resulted in the conclusion that the current performance standard for a DSI system is 95% sulfur capture efficiency. Based on the information that they have collected; the EPA has requested that Aurora Energy revise their assessment to account for a DSI system with a 95% capture efficiency as opposed to the 80% efficient system previously provided. The EPA has also requested that Aurora Energy evaluate the technical feasibility of the other sulfur control technologies specifically with respect to the size of the equipment and the available space on plant property.

Aurora submitted a supplemental SO_2 BACT analysis for EUs 4 through 7 to provide ADEC with updated information to support the existing SO_2 BACT.

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 (FGD) 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 the control of SO_2 emissions from the industrial coal-fired boilers:

(a) Wet Scrubbers (AKA Wet Flue Gas Desulfurization, WFGD)
Post combustion flue gas desulfurization techniques can remove SO_2 formed during combustion by using an alkaline reagent to absorb SO_2 in the flue gas. Flue gasses can be treated using wet, dry, or semi-dry desulfurization processes. In the wet scrubbing system, flue gas is contacted with a solution or slurry of alkaline material in a vessel providing a relatively long residence time. The SO_2 in the flue reacts with the alkali solution or slurry by adsorption and/or absorption mechanisms to form liquid-phase salts. These salts are dried to about one percent free moisture by the heat in the flue gas. These solids are entrained in the flue gas and carried from the dryer to a PM collection device, such as a baghouse.

The lime and limestone wet scrubbing process uses a slurry of calcium oxide or limestone to absorb SO_2 in a wet scrubber. Control efficiencies in excess of 91 percent for lime and 94 percent for limestone over extended periods are possible. Sodium scrubbing processes generally employ a wet scrubbing solution of sodium hydroxide or sodium carbonate to absorb SO_2 from the flue gas. Sodium scrubbers are generally limited to smaller sources because of high reagent costs and can have SO_2 removal efficiencies of up to 96.2 percent. The double or dual alkali system uses a clear sodium alkali solution for SO_2 removal followed by a regeneration step using lime or limestone to recover the sodium alkali and produce a calcium sulfite and sulfate sludge. SO_2 removal efficiencies of 90 to 96 percent are possible. Aurora's updated BACT submittal includes a finding from Stanley Consultants, Inc. (SCI) that the existing facility does not have enough space available on site to install and operate a WFGD control system.

(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. Aurora's updated BACT submittal includes a finding from SCI that the existing facility does not have enough space available on site to install and operate a SDA control system.

(c) Dry Sorbent Injection (DSI)
DSI 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 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. Aurora's updated BACT submittal includes a finding from SCI that the existing facility does not have enough space available on site to install and operate a DSI control system. However, Aurora advanced this control technology past Step 2 of the BACT process, and their quote from SCI claimed that DSI will achieve the highest SO_2 removal rate of the various flue gas desulfurization (FGD) controls.

The Department concurs with Aurora that DSI systems are less complex than the other SO_2 control technologies, including WFGD, CDS, and SDA. A DSI system typically requires less complex material handling and storage and transport equipment. The injection of the sorbent typically occurs in a section of duct work or in a simple reaction chamber. Based on Aurora's concern regarding space constraints and relative implementation costs, the Department agrees that DSI is the most technically and economically feasible SO_2 Control for the Chena Power Plant and has advanced this control for further consideration for the coal-fired boilers.

(d) Low Sulfur Coal
Aurora purchases coal from the Usibelli Coal Mine located in Healy, Alaska. This coal mine is located 115 miles south of Fairbanks. The coal mined at Usibelli is sub-bituminous coal and has a relatively low sulfur content with guarantees of less than 0.4 percent by weight. Usibelli Coal Data Sheets indicate a range of 0.08 to 0.28 percent Gross As Received (GAR) percent Sulfur (%S). According to the U.S. Geological Survey, coal with less than one percent sulfur is classified as low sulfur coal. The Department considers the use of low sulfur coal a technically feasible control technology for the industrial coal-fired boilers. Because the Permittee already combusts low sulfur coal, this control option represents the baseline emissions rate, or a 0% emissions control.

(e) Good Combustion Practices (GCPs)
GCPs during coal-firing means the boilers will be operated to obtain an optimum air/fuel mixture in the combustion zone as verified by periodic direct and indirect combustion chamber observations, maintaining overall excess oxygen levels high enough to complete combustion while maximizing boiler thermal efficiency, and by providing sufficient residence time to achieve complete combustion as provided by original equipment design.

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

(f) Circulating Dry Scrubber (CDS)
This demonstrated technology can achieve SO_2 removal rates comparable to WFGD. CDS technology utilizes a dry circulating fluid bed and an ESP or Fabric Filter for utility scale flue gas desulfurization. CDS technology lends well for small footprints and adequate SO_2 removal. CDS technology is designed for relatively small installations with limited space and perform well with medium-high sulfur coals. Aurora's updated BACT submittal includes a finding from SCI that the existing facility does not have enough space available on site to install and operate a CDS control system.

Step 2 - Eliminate Technically Infeasible SO_2 Control Technologies for Coal-Fired Boilers
As discussed in Step 1, After the Department's review of Aurora's January 25, 20024 submittal from SCI titled, "Best Available Control Technology Analysis – Independent Assessment of Technical Feasibility and Capital Cost, Addendum #1," the Department has eliminated WFGD, CDS, and SDA as technically infeasible due to physical space constraints at the Chena Power Plant.

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 the control of SO_2 emissions from the coal-fired industrial boilers:

(c)	Dry Sorbent Injection (Duct Sorbent Injection)	(90-95% Control)
(e)	Good Combustion Practices	(Less than 40% Control)
(d)	Low Sulfur Coal	(0% Control, Baseline)

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

Step 4 - Evaluate the Most Effective Controls

Aurora BACT Proposal

On January 26, 2024 Aurora submitted a revised Supplemental BACT Analysis for the control of SO_2 emissions. Aurora provided an economic estimate from SCI for the costs of installing and operating a DSI control system that included estimates from BACT Process Systems, Inc. for the cost of the DSI system itself and from Andritz Inc. for the cost estimate of upgrading the existing baghouse system. A summary of the analysis is shown below:

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

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Dry Sorbent Injection	639.5	607.6	82,545,945	13,276,117	21,851
Capital Recovery Factor = 0.0931 of total capital investment (CRF = i(1+i) n / ((1+i) n -1) [CCM Section 1, Chapter 2, page 22] with an interest rate of 8.5% for a 30 year life cycle)					

While implementing DSI is technically feasible, Aurora contends that the economic analysis indicates the level of SO_2 reduction does not justify the use of DSI for the coal-fired boilers based on the perceived high implementation costs.

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

(a) Use of low sulfur coal at all times the boilers are in operation;

(b) Good combustion practices; and

(c) SO_2 emission limit from the coal-fired boilers not to exceed 0.301 lb/MMBtu (3-hr average).[14]

Department Evaluation of BACT for SO_2 Emissions from Industrial Coal-Fired Boilers

The Department revised Aurora's January 26, 2024's cost estimate provided for the installation of DSI by changing the Direct Installation Costs (DIC) and Total Indirect Costs (TIC) to reflect relative ratios that more closely align with Section 5 – SO_2 and Acid Gas Controls of the EPA Air Pollution Control Cost Manual (CCM).[15] The Department found that Aurora's January 26, 2024, cost estimate showed disproportionate ratios of TIC and Purchased Equipment and Material Cost (PEMC or PEC in the CCM), compared to the CCM's. In the CCM, direct and indirect costs represent approximately 75% and 45% of PEMC respectively, whereas in Aurora's latest cost estimate they represent approximately 380% each. Given that this portion of Aurora's estimates are not direct vendor quotes, but instead engineering estimates from a consultant, the Department re-calculated the TDC and TIC. The Department conservatively estimated the DIC at 150% of the PEC, which changed the value from approximately 36.3 million dollars to approximately 14.4 million dollars. Additionally, the Department changed the engineering services value from approximately 7.5 million dollars to approximately 1.9 million dollars, which is a conservative estimate of 20% of the PEMC. The Department notes that various other categories in the TIC were also lowered because they are calculated as a percentage of the DIC. Additionally, the Department notes that certain line items were left in the calculation to ensure a conservative estimate, such as profit, which is not part of the calculations included in the CCM, and the amount of sorbent needed per year. The Department left the sorbent amount unchanged which accounts for approximately 1.8 million dollars of the Department's calculated approximate 8.1-million-dollar value for Total Annual Costs. This is of note because of the relatively high ratio of unreacted $NaHCO_3$/used NaHCO3 expected in Aurora's calculations. Per Aurora's information regarding ash disposal, the amount of unreacted $NaHCO_3$ is about half of the $NaHCO_3$ used. In its ash generation due to DSI estimate, Aurora listed 1,590 tpy as unreacted $NaHCO_3$ vs 3,175 tpy of $NaHCO_3$ used.

The Department left other assumptions in Aurora's cost estimate for DSI unchanged, including the need for installing a larger baghouse to handle the additional loading of sorbent in the exhaust stream, estimation of annualized costs, using the combined unrestricted potential to emit

[14] Upon Aurora's request, on April 5, 2023, the SO_2 emission limit of 0.301 lb/MMBtu was incorporated into Condition 15 of the federally enforceable Title V Permit AQ0315TVP04, Revision 2, effective May 5, 2023.

[15] EPA Air Pollution Control Cost Manual and associated and associated cost spreadsheets are available at the following website: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

for the four coal-fired boilers, a baseline emission rate of 0.301 lb SO_2/MMBtu,[14] an interest rate of 8.5%, and a 30 year equipment life to address EPA's comment regarding equipment lifetime.

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)
Dry Sorbent Injection	639.5	607.6	$43,809,891	$8,122,262	$13,368
Capital Recovery Factor = 0.0931 of total capital investment (CRF = i(1+i) n / ((1+i) n -1) [CCM Section 1, Chapter 2, page 22] with an interest rate of 8.5% for a 30 year life cycle)					

The Department's economic analysis appears to indicate that 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. However, Aurora submitted a revised affordability analysis to the Department on March 15, 2024, (a redacted version of this submittal is included in the SIP Appendix to the Control Strategies Chapter), which claims that Aurora cannot afford to install DSI controls, referencing the financial indicators identified in Step 4 of the BACM/BACT process outlined in the Federal Register, Vol. 81, No.164, Wednesday August 24, 2016. pg. 58085.

Aurora's claim that DSI is cost prohibitive is based on the anticipated cost of installing and operating the new DSI control equipment divided by the anticipated sales of electricity and district heat, known as the cost/sales ratio. The EPA's November 2006 Small Business Regulatory Enforcement Fairness Act (SBREFA) Guidance Document[16] states the following about a cost/sales ratio of 3% or greater (the upper threshold), "The upper threshold defines a level of economic impact that would be unquestionably significant for a small entity." Aurora calculated a cost/sales ratio that was significantly higher than the 3% upper threshold found in the SBREFA Guidance Document. Therefore, based on the financial information provided by Aurora, the Department concurs that the implementation of DSI will yield an unacceptable adverse economic impact on the company, and therefore rejected as BACT.

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 EUs 4 through 7 shall be controlled by operating and maintaining Good Combustion Practices at all times the units are in operation;

(b) SO_2 emissions from EUs 4 through 7 shall not exceed 0.301 lb/MMBtu[17] averaged over a 3-hour period; and

[16] The EPA's SBREFA Guidance Document is available at: https://www.epa.gov/reg-flex/learn-about-regulatory-flexibility-act.

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

(c) 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 4-4 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[18]
Fort Wainwright	6 Coal-Fired Boilers	1380 MMBtu/hr (combined)	0.04 lb/MMBtu[19]	Dry Sorbent Injection Limited Operation
UAF	Dual Fuel-Fired Boiler	295.6 MMBtu/hr	0.10 lb/MMBtu[20]	Fluidized Bed Limestone Injection
Chena	4 Coal-Fired Boilers	497 MMBtu/hr (combined)	0.301 lb/MMBtu[17]	Good Combustion Practices

[18] Note that the Department removed the reference to low sulfur coal, which was never selected as part of the top down BACT determination process and is already the only type of coal available to sources in Alaska.
[19] BACT limit is a vendor emissions guarantee.
[20] The Department selected the UAF BACT SO_2 emissions limit using a statistical analysis of historical CEMS emissions data.

6. BACT DETERMINATION SUMMARY

Table 6-1. Proposed NOx BACT Limits

EU ID	Description	Rating/Size	Proposed BACT Limit	Proposed BACT Control
4	Chena 1 Coal Fired Boiler	76 MMBtu/hr	None EPA approved a comprehensive precursor demonstration for NOx See details in the Section 1 Introduction	
5	Chena 2 Coal Fired Boiler	76 MMBtu/hr		
6	Chena 3 Coal Fired Boiler	76 MMBtu/hr		
7	Chena 5 Coal Fired Boiler	269 MMBtu/hr		

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

EU ID	Description	Rating/Size	Proposed BACT Limit	Proposed BACT Control
4	Chena 1 Coal Fired Boiler	76 MMBtu/hr	0.045 lb/ MMBtu	Bag House Fabric Filter Good Combustion Practices
5	Chena 2 Coal Fired Boiler	76 MMBtu/hr		
6	Chena 3 Coal Fired Boiler	76 MMBtu/hr		
7	Chena 5 Coal Fired Boiler	269 MMBtu/hr		
1	Coal Preparation Plant	75 tons/hr	0.34 tpy	Partial Enclosure & Fugitive Dust Control Plan
2	Coal Stockpile	0.59 acre	0.14 tpy	Fugitive Dust Control Plan
3	Ash Vacuum Pump Exhaust	24,187 tons ash/yr	0.24 tpy	Fabric Filter, Enclosure, & Fugitive Dust Control Plan
8	Truck Bay Ash Loadout	N/A	0.0004 tpy	Enclosure and Fugitive Dust Control Plan

Table 6-3. Proposed SO_2 BACT Limits

EU ID	Description	Rating/Size	Proposed BACT Limit	Proposed BACT Control[18]
4	Chena 1 Coal Fired Boiler	76 MMBtu/hr	0.301 lb/MMBtu	Good Combustion Practices
5	Chena 2 Coal Fired Boiler	76 MMBtu/hr		

6	Chena 3 Coal Fired Boiler	76 MMBtu/hr		
7	Chena 5 Coal Fired Boiler	269 MMBtu/hr		

Chena Power Plant SO_2 BACT MR&R

Stationary Source: Chena Power Plant

Emission Units: EU IDs 4, 5, 6 (76 MMBtu/hr – Coal Boilers) and 7 (269 MMBtu/hr – Coal Boiler)

Pollutant of Concern: SO_2	
BACT Measure	**Monitoring, Recordkeeping and Reporting Requirements**
0.301 lb/MMBtu (3-hr avg)	• Conduct an initial SO_2 source test at maximum load and report results as required in the corresponding Operating Permit.
Good Combustion Practices	• Keep records of maintenance conducted on emission units to comply with this BACT measure. • Keep a copy of the manufacturer's and the operator's recommended maintenance procedures.

DEPARTMENT OF ENVIRONMENTAL CONSERVATION
AIR QUALITY CONTROL MINOR PERMIT

Minor Permit: AQ0315MSS02 Revision 1 Final Date – October 28, 2024
Rescinds Permit: AQ0315MSS02

The Alaska Department of Environmental Conservation (Department), under the authority of AS 46.14 and 18 AAC 50, issues Air Quality Control Minor Permit AQ0315MSS02 Revision 1 to the Permittee listed below.

Permittee:	**Aurora Energy, LLC** 100 Cushman Street, Suite 210 Fairbanks, AK 99701
Stationary Source:	**Chena Power Plant**
Location:	1206 1st Avenue Fairbanks, Alaska 99701
Project:	$PM_{2.5}$ Serious Nonattainment State Implementation Plan (SIP)
Permit Contact:	Dave Fish 907-452-8767 dfish@usibelli.com

The Permittee submitted an application for Minor Permit AQ0315MSS02 under AS 46.14.130(c)(2) because the Department found that public health or air quality effects provided a reasonable basis to regulate the stationary source. This minor permit was issued to make the Fairbanks $PM_{2.5}$ State Implementation Plan's control strategies for the Aurora Energy, LLC's Chena Power Plant enforceable, as required under the State Air Quality Control Plan adopted on November 19, 2019.

With the issuance of Minor Permit AQ0315MSS02 Revision 1, the Department finds that public health or air quality effects still provide a reasonable basis to regulate the stationary source. This minor permit is issued to make the Fairbanks $PM_{2.5}$ State Implementation Plan's control strategies for the Aurora Energy, LLC's Chena Power Plant enforceable, as required under the State Air Quality Control Plan adopted on November 19, 2019.

This permit satisfies the obligation of the Permittee to obtain a minor permit under 18 AAC 50. As required by AS 46.14.120(c), the Permittee shall comply with the terms and conditions of this permit.

The Department's Standard Permit Condition XIII – Coal Fired Boilers (as adopted July 22, 2020) and the Department's Default COMs Audit Procedures (as adopted August 20, 2008), have both been adopted into this minor permit.

James R. Plosay, Manager
Air Permits Program

Table of Contents

Abbreviations and Acronyms

AAC....................Alaska Administrative Code
ADEC ....Alaska Department of Environmental Conservation
AOS ....Air Online Services
AS ....Alaska Statutes
ASTM ....American Society for Testing and Materials
BACT ....best available control technology
bhp ....brake horsepower
CDX....................Central Data Exchange
CEDRI ....Compliance and Emissions Data Reporting Interface
C.F.R. ....Code of Federal Regulations
CAA....................Clean Air Act
CO ....carbon monoxide
Department ....Alaska Department of Environmental Conservation
dscf ....dry standard cubic foot
EPA ....US Environmental Protection Agency
EU.......................emissions unit
gr/dscf.................grain per dry standard cubic foot (1 pound = 7000 grains)
gph ....gallons per hour
HAPs ....hazardous air pollutants [as defined in AS 46.14.990]
hp ....horsepower
ID........................emissions unit identification number
kPa ....kiloPascals
LAER..................lowest achievable emission rate
MACT ....maximum achievable control technology [as defined in 40 C.F.R. 63]
MMBtu/hr...........million British thermal units per hour
MMscf ....million standard cubic feet
MR&R ....monitoring, recordkeeping, and reporting
NESHAPs............National Emission Standards for Hazardous Air Pollutants [as contained in 40 C.F.R. 61 and 63]
NOx ....nitrogen oxides
NRE.....................nonroad engine
NSPS ....New Source Performance Standards [as contained in 40 C.F.R. 60]
O & M ....operation and maintenance
O_2.........................oxygen
PAL ....plantwide applicability limitation
PM-10..................particulate matter less than or equal to a nominal 10 microns in diameter
PM-2.5.................particulate matter less than or equal to a nominal 2.5 microns in diameter
ppm ....parts per million
ppmv, ppmvd........parts per million by volume on a dry basis
ppmw ……………parts per million by weight
psia ....pounds per square inch (absolute)
PSD ....prevention of significant deterioration
PTE......................potential to emit
SIC.......................Standard Industrial Classification
SIP ....State Implementation Plan
SPC......................Standard Permit Condition or Standard Operating Permit Condition
SO_2 ....sulfur dioxide
The Act................Clean Air Act
TPH ....tons per hour
tpy........................tons per year
VOC ....volatile organic compound [as defined in 40 C.F.R. 51.100(s)]
VOL.....................volatile organic liquid [as defined in 40 C.F.R. 60.111b, Subpart Kb]
vol% ....volume percent
wt% ....weight percent
$wt\%S_{fuel}$ ....weight percent of sulfur in fuel

Section 1 Emissions Unit Inventory

Emissions Unit (EU) Authorization. The Permittee is authorized to install and operate the EUs listed in Table A and B in accordance with this minor permit terms and conditions and the applicable operating permit issued to the stationary source under AS 46.14 and 18 AAC 50. The information in Table A is for identification purposes only, unless otherwise noted in the permit.

Table A – Emission Unit Inventory

EU ID	Emissions Unit Name	Emissions Unit Description	Rating/Size	Installation or Construction Date
1	Coal Preparation Plant	Exhaust and Fugitive Emissions	75 tons/hour	1950[1]
2	Coal Stockpile	Fugitive Emissions	0.59 acre	1950[2]
3	Ash Vacuum Pump Exhaust	Ash System Baghouse Exhaust	24,187 tons/yr (of ash)	1997
4	Chena 1 Coal-Fired Boiler	Full Stream Baghouse Exhaust	76.8 MMBtu/hr	1952
5	Chena 2 Coal-Fired Boiler	Full Stream Baghouse Exhaust	76.8 MMBtu/hr	1952
6	Chena 3 Coal-Fired Boiler	Full Stream Baghouse Exhaust	76.8 MMBtu/hr	1954
7	Chena 5 Coal-Fired Boiler	Full Stream Baghouse Exhaust	254.7 MMBtu/hr	1970

1. EU ID 1 was modified in 1990.
2. EU ID 2 was modified in 2013.

Table B – Fugitive Emission Unit Inventory

EU ID	Emissions Unit Name	Emissions Unit Description	Rating/Size	Installation or Construction Date
8	Truck Bay Ash Loadout	Bottom of silo – Fugitive Emissions	N/A	1952
9	Paved Roadways	Fugitive Emissions	N/A	1950

1. The Permittee shall comply with all applicable provisions of AS 46.14 and 18 AAC 50 when installing a replacement EU, including any applicable minor or construction permit requirements.

Section 3 State Implementation Plan (SIP) Requirements

Fairbanks $PM_{2.5}$ Serious Nonattainment Area SIP Requirements

5. **Coal-Fired Boiler Emissions Limits.** The Permittee shall limit the emissions from the coal-fired boilers EU IDs 4 through 7 as specified in Table C.

Table C – EU IDs 4 through 7 SIP BACT Limits

Pollutant	BACT Control	BACT Emissions Limit
$PM_{2.5}$	Good Combustion Practices	0.045 lb/MMBtu (3-hour average)
	Full Stream Baghouse System	State Visible Emissions Standard 18 AAC 50.055(a)(9)

5.1 For EU IDs 4 through 7 the Permittee shall:

a. Conduct a one-time source test on the common stack of EU IDs 4 through 7 after the control device, in accordance with Section 6, within 12 months of permit issuance, to demonstate compliance with the $PM_{2.5}$ emissions limit listed in Table C.

(i) Conduct the source test at the maximum achieveable load of EU IDs 4 through 7 in accordance with the procedures specified in 40 CFR 51, Appendix M, Method 201A and, if applicable, Method 202 as provided in Method 201A.

(ii) Emission results shall be reported as the arithmetic 3-hour average of all valid test runs and shall be written in units of lb/MMBtu.

(iii) The Permittee shall report the results of the source test in accordance with Condition 29.

(iv) Include a summary of the source test results in the next operating report that is due after the submittal date of the source test report in accordance with Condition 14.

b. Report the compliance status with the $PM_{2.5}$ emissions limit in Table C in accordance with each annual compliance certification described in Condition 15.

c. Operate the EU with fabric filters and maintain good combustion practices at all times of operation.

(i) Keep records of the date and time identifying each time-period that an EU is operated without a fabric filter.

(ii) Perform regular maintenance according to the manufacturer's and the operator's maintenance requirements and procedures.

(iii) Keep records of any maintenance that would have a significant effect on emissions. The records may be kept in electronic format.

(iv) Keep a copy of the manufacturer's and the operator's maintenance procedures.

(v) Operate the EU consistent with manufacturer's recommended combustion settings (e.g., maximum CO, excess air in flue gas, and other relevant parameters) or those established during the source test conducted to demonstrate compliance with the BACT emissions limit in Table C.

d. Monitor visible emissions to ensure compliance with the State Visible Emissions Standard in Table C using a Continuous Opacity Monitoring System (COMS).

(i) The Permittee shall demonstrate compliance with Condition 5.1d by following the Department's Standard Permit Condition XIII – Coal Fired Boilers (as adopted July 22, 2020), as well as the Department's Default COMs Audit Procedures (as adopted August 20, 2008), both of which are available on the following website: https://dec.alaska.gov/air/air-permit/standard-conditions/.

e. Report in accordance with Condition 14

(i) a summary of the maintenance records collected under Condition 5.1c(iii); and

(ii) highest 6-minute average opacity measured by the COMs during the reporting period under Condition 5.1d.

f. Report in accordance with Condition 13, whenever

(i) an emissions rate determined by the source test required by Condition 5.1a exceeds the limit in Table C;

(ii) a boiler is operated without a fabric filter as recorded in Condition 5.1c(i);or

(iii) any of Conditions 5.1a through 5.1e are not met.

6. **Material Handling Emissions Limits.** The Permittee shall limit the emission from the material handling EU IDs 1 and 3 as specified in Table D.

Table D – EU IDs 1 and 3 SIP BACT Limits

Pollutant	EU ID	BACT Control	BACT Emissions Limit
$PM_{2.5}$	1	Partial Enclosure	0.34 tpy
	3	Full Enclosure Fabric Filter	0.24 tpy

6.1 For EU IDs 1 and 3, the Permittee shall demonstrate compliance with the $PM_{2.5}$ requirements in Table D as follows:

a. For each of the EUs, the Permittee shall within six months of issuance of this permit either:

(i) Provide vendor data documenting that EU IDs, 1 and 3 meet the emissions limits of Table D; or

(ii) Perform an initial Method 9 observation. For all Method 9 observations, observe emissions unit exhaust for 18 consecutive minutes to obtain a minimum of 72 consecutive 15-second opacity observations in accordance with Method 9 of 40 C.F.R. 60, Appendix A-4; or

(iii) Provide documentation of the previous submittal where the obligations of Conditions 6.1a(i) or 6.1a(ii) were met.

b. If the 18 consecutive minutes of the initial Method 9 observations conducted under Condition 6.1a(ii) result in an 18-minute average opacity greater than 20 percent, the Permittee shall conduct a $PM_{2.5}$ source test in accordance with the methods and procedures specified in 40 C.F.R. 60 Appendix A and Section 6 to determine the $PM_{2.5}$ emission rate.

(i) If required under Condition 6.1b, the Permittee shall report the results of the source test(s) in accordance with Condition 29.

(ii) If required under Condition 6.1a(ii), include copies of the results of initial Method 9 observations conducted under Condition 6.1a(ii) in the first operating report required under Condition 14.

c. Report the compliance status with the $PM_{2.5}$ emissions limits in Table D in accordance with each annual compliance certification described in Condition 15.

6.2 For EU ID 1, the Permittee shall:

a. Operate the EU in a partial enclosure.

(i) Keep records of the date and time identifying each time period the EU is operated outside of a partial enclosure.

6.3 For EU ID 3, the Pertmittee shall:

a. Operate the EU with fabric filters at all times of operation.

(i) Keep records of the date and time identifying each time period that the EU is operated without a fabric filter.

(ii) Perform regular maintenance regular maintenance according to the manufacturer’s and the operator’s maintenance requirements and procedures.

(iii) Keep records of any maintenance that would have a significant effect on emissions. The records may be kept in electronic format.

(iv) Keep a copy of the manufacturer’s and the operator’s maintenance procedures.

b. Operate the EU in a full enclosure.

(i) Keep records of the date and time identifying each time period the EU is operated outside of a full enclosure.

6.4 Report in accordance with Condition 14 a summary of the records collected under Condition 6.3a(iii).

6.5 Report in accordance with Condition 13, whenever

a. an emissions rate exceeds a limit in Table D;

b. EU ID 1 is operated outside of a partial enclosure as recorded in Condition 6.2a(i);

c. EU ID 3 is operated without a fabric filter as recorded in Condition 6.3a(i);

d. EU ID 3 is operated outside of a full enclosure as recorded in Condition 6.3b(i); or

e. any of Conditions 6.1 through 6.4 are not met.

7. **Coal Stockpile.** The Permittee shall limit the $PM_{2.5}$ emissions from the coal stockpile EU ID 2 as specified in Table E.

Table E – EU ID 2 SIP BACT Limits

Pollutant	BACT Control	BACT Emissions Limit
$PM_{2.5}$	Best Management Practices	0.14 tpy

7.1 For EU ID 2, the Permittee shall demonstrate compliance with the $PM_{2.5}$ requirements in Table E as follows:

a. Perform best management practices to minimize fugitive emissions from the coal stockpile EU ID 2.

(i) Keep records of the date and time identifying each time that futigive emissions were observed from EU ID 8 and what measures were taken to minimize the emissions.

b. Report the compliance status with the $PM_{2.5}$ emissions limit in Table E in accordance with each annual compliance certification described in Condition 15.

c. Report in accordance with Condition 13, whenever

(i) a limit in Table E is exceeded; or

(ii) whenever any of the requirements in Conditions 7.1a through 7.1b are not met.

8. **Truck Bay Ash Loadout.** The Permittee shall limit the $PM_{2.5}$ emissions from the truck bay ash loadout EU ID 8 as specified in Table F.

Table F – EU ID 8 SIP BACT Limits

Pollutant	BACT Control	BACT Emissions Limit
$PM_{2.5}$	Full Enclosure	0.0004 tpy

8.1 For EU ID 8, the Permittee shall demonstrate compliance with the $PM_{2.5}$ requirements in Table F as follows:

a. Operate EU ID 8 in an enclosure during all ash loadout operations.

(i) Monitor that overhead door(s) at truck bay ash loadout building are closed while loading the trucks. Monitor that ash truck bodies are free of ash before they leave the building, and that their loads are tarped before they leave the building area. Minimize fugitive dust from coal ash handling operations.

(ii) Keep records of the date and time identifying each time period that EU ID 8 was not enclosed during ash loadout operations.

b. Report the compliance status with the $PM_{2.5}$ emissions limit in Table F in accordance with each annual compliance certification described in Condition 15.

c. Report in accordance with Condition 13, whenever

(i) a limit in Table F is exceeded; or

(ii) whenever any of the requirements in Conditions 8.1a through 8.1b are not met.

Section 4 Recordkeeping, Reporting, and Certification Requirements

Recordkeeping Requirements

9. The Permittee shall keep all records required by this permit for at least five years after the date of collection, including:

    9.1 Copies of all reports and certifications submitted pursuant to this section of the permit; and

    9.2 Records of all monitoring required by this permit, and information about the monitoring including:

    a. the date, place, and time of sampling or measurements;

    b. the date(s) analyses were performed;

    c. the company or entity that performed the analyses;

    d. the analytical techniques or methods used;

    e. the results of such analyses; and

    f. the operating conditions as existing at the time of sampling or measurement.

Reporting Requirements

10. **Certification.** The Permittee shall certify any permit application, report, affirmation, or compliance certification submitted to the Department and required under the permit by including the signature of a responsible official for the permitted stationary source following the statement: *"Based on information and belief formed after reasonable inquiry, I certify that the statements and information in and attached to this document are true, accurate, and complete."* Excess emission reports must be certified either upon submittal or with an operating report required for the same reporting period. All other reports and other documents must be certified upon submittal.

    10.1 The Department may accept an electronic signature on an electronic application or other electronic record required by the Department if the person providing the electronic signature

    a. uses a security procedure, as defined in AS 09.80.190, that the Department has approved; and

    b. accepts or agrees to be bound by an electronic record executed or adopted with that signature.

11. **Submittals.** Unless otherwise directed by the Department or this permit, the Permittee shall submit to the Department one certified copy of reports, compliance certifications, and/or other submittals required by this permit. The Permittee may submit the documents electronically or by hard copy.

    11.1 Submit the certified copy of reports, compliance certifications, and/or other submittals in accordance with the submission instructions on the Department's Standard Permit Conditions web page at http://dec.alaska.gov/air/air-permit/standard-conditions/standard-condition-xvii-submission-instructions/.

12. **Information Requests.** The Permittee shall furnish to the Department, within a reasonable time, any information the Department requests in writing to determine whether cause exists to modify, revoke, reissue, or terminate the permit or to determine compliance with the permit. Upon request, the Permittee shall furnish to the Department copies of records required to be kept by the permit. The Department may require the Permittee to furnish copies of those records directly to the federal administrator.

13. **Excess Emissions and Permit Deviation Reports.** The Permittee shall report excess emissions and permit deviations as follows:

13.1 **Excess Emissions Reporting.** The Permittee shall report all emissions or operations that exceed emissions standards or limits of this permit as follows:

a. In accordance with 18 AAC 50.240(c), as soon as possible, report

(i) excess emissions that present a potential threat to human health or safety; and

(ii) excess emissions that the Permittee believes to be unavoidable.

b. In accordance with 18 AAC 50.235(a), within two working days after the event commenced or was discovered, report an unavoidable emergency, malfunction, or nonroutine repair that causes emissions in excess of a technology-based emission standard.

c. If a continuous or recurring excess emissions is not corrected within 48 hours of discovery, report within 72 hours of discovery unless the Department provides written permission to report under Condition 13.1d.

d. Report all other excess emissions not described in Conditions 13.1a, 13.1b, and 13.1c within 30 days after the end of the month during which the excess emissions occurred or as part of the next routine operating report in Condition 14 for excess emissions that occurred during the period covered by the report, whichever is sooner.

e. If requested by the Department, the Permittee shall provide a more detailed written report to follow up on an excess emissions report.

13.2 **Permit Deviations Reporting.** For permit deviations that are not "excess emissions," as defined under 18 AAC 50.990:

a. Report all other permit deviations within 30 days after the end of the month during which the deviation occurred or as part of the next routine operating report in Condition 14 for permit deviations that occurred during the period covered by the report, whichever is sooner.

13.3 **Reporting Instructions.** When reporting either excess emissions or permit deviations, the Permittee shall report using the Department's online form for all such submittals, beginning no later than September 7, 2023. The form can be found at the Division of Air Quality's Air Online Services (AOS) system webpage http://dec.alaska.gov/applications/air/airtoolsweb using the Permittee Portal option. Alternatively, upon written Department approval, the Permittee may submit the form contained in Section 7 of this permit. The Permittee must provide all information called for by the form that is used. Submit the report in accordance with the submission instructions on the Department's Standard Permit Conditions webpage found at http://dec.alaska.gov/air/air-permit/standard-conditions/standard-conditions-iii-and-iv-submission-instructions/.

14. **Operating Reports.** During the life of this permit[2], the Permittee shall submit to the Department an operating report in accordance with Conditions 10 and 11 by August 1 for the period January 1 to

[2] *Life of this permit* is defined as the permit effective dates, including any periods of reporting obligations that extend beyond the permit effective dates. For example if a permit expires prior to the end of a calendar year, there is still a reporting obligation to provide operating reports for the periods when the permit was in effect.

June 30 of the current year and by February 1 for the period July 1 to December 31 of the previous year.

14.1 The operating report must include all information required to be in operating reports by other conditions of this permit, for the period covered by the report.

14.2 When excess emissions or permit deviations that occurred during the reporting period are not included with the operating report under Condition 14.1, the Permittee shall identify

a. the date of the excess emissions or permit deviation;

b. the equipment involved;

c. the permit condition affected;

d. a description of the excess emissions or permit deviation; and

e. any corrective action or preventive measures taken and the date(s) of such actions; or

14.3 when excess emissions or permit deviation reports have already been reported under Condition 13 during the period covered by the operating report, the Permittee shall either

a. include a copy of those excess emissions or permit deviation reports with the operating report; or

b. cite the date(s) of those reports.

15. **Annual Compliance Certification.** Each year by March 31, the Permittee shall compile and submit to the Department an annual compliance certification report according to Condition 11.

15.1 Certify the compliance status of the stationary source over the preceding calendar year consistent with the monitoring required by this permit, as follows:

a. Identify each term or condition set forth in Section 2 through Section 6, that is the basis of the certification;

b. Breifly describe each method used to determine the compliance status;

c. state whether compliance is intermittent or continuous; and

d. identify each deviation and take it into account in the compliance certification.

15.2 In addition, submit a copy of the report directly to the Clean Air Act Compliance Manager, US EPA Region 10, ATTN: Air Toxics and Enforcement Section, Mail Stop: 20-C04, 1200 Sixth Avenue, Suite 155, Seattle, WA 98101-3188.

Section 6 General Source Test Requirements

22. **Requested Source Tests.** In addition to any source testing explicitly required by this permit, the Permittee shall conduct source testing as requested by the Department to determine compliance with applicable permit requirements.

23. **Operating Conditions.** Unless otherwise specified by an applicable requirement or test method, the Permittee shall conduct source testing

    23.1 at a point or points that characterize the actual discharge into the ambient air; and

    23.2 at the maximum rated burning or operating capacity of the emissions unit or another rate determined by the Department to characterize the actual discharge into the ambient air.

24. **Reference Test Methods.** The Permittee shall use the following references for test methods when conducting source testing for compliance with this permit:

    24.1 Source testing for the reduction in visibility through the exhaust effluent must be conducted in accordance with the procedures set out in 40 C.F.R. 60, Appendix A, Reference Method 9. The Permittee may use the form in Attachment 1 of this permit to record data.

    24.2 Source testing for emissions of total particulate matter, sulfur compounds, nitrogen compounds, carbon monoxide, lead, volatile organic compounds, fluorides, sulfuric acid mist, municipal waste combustor organics, metals and acid gases must be conducted in accordance with the methods and procedures specified in 40 C.F.R. 60, Appendix A.

    24.3 Source testing for emissions of PM_{10} and $PM_{2.5}$ must be conducted in accordance with the procedures specified in 40 C.F.R. 51, Appendix M, Methods 201 or 201A and 202.

    24.4 Source testing for emissions of any contaminant may be determined using an alternative method approved by the Department in accordance with 40 C.F.R. 63 Appendix A, Method 301.

25. **Excess Air Requirements.** To determine compliance with this permit, standard exhaust gas volumes must include only the volume of gases formed from the theoretical combustion of the fuel, plus the excess air volume normal for the specific emissions unit type, corrected to standard conditions (dry gas at 68° F and an absolute pressure of 760 millimeters of mercury).

26. **Test Deadline Extension.** The Permittee may request an extension to a source test deadline established by the Department. The Permittee may delay a source test beyond the original deadline only if the extension is approved in writing by the Department's appropriate division director or designee.

27. **Test Plans.** Before conducting any source tests, the Permittee shall submit a plan to the Department. The plan must include the methods and procedures to be used for sampling, testing, and quality assurance and must specify how the emissions unit will operate during the test and how the Permittee will document that operation. The Permittee shall submit a complete plan within 60 days after receiving a request under Condition 22 and at least 30 days before the scheduled date of any test unless the Department agrees in writing to some other time period. Retesting may be done without resubmitting the plan.

28. **Test Notification.** At least 10 days before conducting a source test, the Permittee shall give the Department written notice of the date and time the source test will begin.

29. **Test Reports.** Within 60 days after completing a source test, the Permittee shall submit one certified copy of the results in the format set out in the *Source Test Report Outline*, adopted by

reference in 18 AAC 50.030. The Permittee shall certify the results in the manner set out in Condition 10. If requested in writing by the Department, the Permittee must provide preliminary results in a shorter period of time specified by the Department.

Fort Wainwright BACT Cover Page

Contents

ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION
Air Permits Program

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

Prepared by: Dave Jones
Reviewed by: Moses Coss
Final Date: October 21, 2024

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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 in Fairbanks, AK are either owned and operated by a private utility company, Doyon Utilities, LLC (DU), or by U.S. Army Garrison Fort Wainwright (FWA). The two entities, DU and FWA, comprise a single stationary source operating under two permits.

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

The initial BACT Determination for Fort Wainwright was included in Part 2 of Appendix III.D.7.07 Control Strategies Chapter, in the State Air Quality Control Plan adopted on November 19, 2019, with amendments adopted on November 18, 2020, as part of a complete SIP package.[2] The *EPA's Air Plan Partial Approval and Partial Disapproval; AK, Fairbanks North Star Borough; 2006 24-hour $PM_{2.5}$ Serious Area and 189(d) Plan*[3] published in the Federal Register on December 5, 2023 (*88 Fed. Reg. 84655*) disapproved of Alaska's initial BACT determinations for $PM_{2.5}$ and SO_2 controls.

This BACT addendum addresses the EPA's disapproval of the significant EUs listed in the DU permit AQ1121TVP02, Revision 2 and the FWA permit AQ0236TVP04, for $PM_{2.5}$ and SO_2 controls. The BACT addendum also accounts for EPA's comments listed in Memorandum dated August 24, 2022 from Zach Hedgpeth, LSASD to Matthew Jentgen, ARD.[4] This BACT addendum provides the Department's review of the BACT analysis for $PM_{2.5}$, and BACT analysis for sulfur dioxide (SO_2) emissions, which is a precursor pollutant that can form $PM_{2.5}$ in the atmosphere post combustion.

Since preparing the SIP amendments adopted on November 18, 2020, the Department conducted extensive modeling and found that SO_2 emissions from stationary sources do not significantly

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

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

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

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

contribute to ground level $PM_{2.5}$ concentrations, and that SO_2 BACT emission limits are therefore not required for major stationary sources in the Fairbanks North Star Borough. SO_2 BACT determinations have, however, been included in this BACT Determination Addendum because the SO_2 major source precursor demonstration has not yet been approved by EPA.

Note that the section for oxides of nitrogen (NOx), which is also a precursor pollutant that can form $PM_{2.5}$ in the atmosphere post combustion, has been removed from this addendum because the EPA has approved[3] of the Department's comprehensive NOx precursor demonstration under 40 C.F.R. 51.1006(a)(1) and 51.1010(a)(2)(ii).

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

2. BACT EVALUATION

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

Table A: Privatized Emission Units Subject to BACT Review

EU ID[1]	Description of EU	Rating/Size	Location
1	Coal-Fired Boiler 3	230 MMBtu/hr	Central Heating and Power Plant (CHPP)
2	Coal-Fired Boiler 4	230 MMBtu/hr	CHPP
3	Coal-Fired Boiler 5	230 MMBtu/hr	CHPP
4	Coal-Fired Boiler 6	230 MMBtu/hr	CHPP
5	Coal-Fired Boiler 7	230 MMBtu/hr	CHPP
6	Coal-Fired Boiler 8	230 MMBtu/hr	CHPP
7a	South Coal Handling Dust Collector DC-01	13,150 acfm	CHPP
7b	South Underbunker Dust Collector DC-02	884 acfm	CHPP
7c	North Coal Handling Dust Collector NDC-1	9,250 acfm	CHPP
8	Backup Generator Engine	2,937 hp	CHPP
9	Emergency Generator Engine	353 hp	Building 1032
14	Emergency Generator Engine	320 hp	Building 1563
22	Emergency Generator Engine	35 hp	Building 3565
23	Emergency Generator Engine	155 hp	Building 3587
29a	Emergency Generator Engine	74 hp	Building 3565

EU ID[1]	Description of EU	Rating/Size	Location
30a	Emergency Generator Engine	91 hp	Building 3403
31a	Emergency Generator Engine	74 hp	Building 3724
32a	Emergency Generator Engine	91 hp	Building 4162
33a	Emergency Generator Engine	75 hp	Building 1002
34	Emergency Pump Engine	220 hp	Building 3405
35	Emergency Pump Engine	55 hp	Building 4023
36a	Emergency Generator Engine	161 hp	Building 3563
37	Emergency Generator Engine	75 hp	MH 507
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 hp	Building 3498
38	Fire Pump #1	120 hp	Building 5009
39	Fire Pump #2	120 hp	Building 5009
40	Diesel-Fired Boiler	2.6 MMBtu/hr	Building 5007
50	Emergency Generator Engine	762 hp	Building 1060
51	Emergency Generator Engine	762 hp	Building 1060
52	Emergency Generator Engine	82 hp	Building 1193
53	Emergency Generator Engine	587 hp	Building 1555
54	Emergency Generator Engine	1,059 hp	Building 2117
55	Emergency Generator Engine	212 hp	Building 2117
56	Emergency Generator Engine	176 hp	Building 2088
57	Emergency Generator Engine	212 hp	Building 2296
58	Emergency Generator Engine	71 hp	Building 3004
59	Emergency Generator Engine	35 hp	Building 3028

EU ID[1]	Description of EU	Rating/Size	Location
60a	Emergency Generator Engine	230 hp	Building 3407
61	Emergency Generator Engine	50 hp	Building 3703
62	Emergency Generator Engine	18 hp	Building 5108
63	Emergency Generator	68 hp	Building 1620
64	Emergency Generator	274 hp	Building 1054
65	Emergency Generator	274 hp	Building 4390
66	Emergency Generator	235 hp	Building 3007
67	Emergency Generator	67 hp	Building 2121
68	Emergency Generator	324 hp	Building 3025
69	Emergency Generator	86 hp	Building 3030

Five-Step BACT Determinations

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

Step 1 Identify All Potentially Available Control Technologies

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

Step 2 Eliminate Technically Infeasible Control Technologies:

The Department evaluates the technical feasibility of each control option based on source specific factors in relation to each EU subject to BACT. Based on sound documentation and demonstration, the Department eliminates control technologies deemed technically infeasible due to physical, chemical, and engineering difficulties.

Step 3 Rank the Remaining Control Technologies by Control Effectiveness

The Department ranks the remaining control technologies in order of control effectiveness with the most effective at the top.

Step 4 Evaluate the Most Effective Controls and Document the Results as Necessary

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

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

3. BACT DETERMINATION FOR NOx

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

4. BACT DETERMINATION FOR $PM_{2.5}$

The Department based its $PM_{2.5}$ assessment on BACT determinations found in the RBLC, internet research, and BACT analyses submitted to the Department by GVEA for the North Pole Power Plant and Zehnder Facility, Aurora for the Chena Power Plant, and UAF for the Combined Heat and Power Plant.

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

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,[6] pulse-jet,[7] and reverse-air.[8] Fabric filter systems have control efficiencies of 95% to 99.9%, and are generally specified to meet a discharge concentration of filterable particulate (e.g., 0.01 grains per dry standard cubic feet). The Department considers fabric filters a technically feasible control technology for the industrial coal-fired boilers.

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

[6] https://www3.epa.gov/ttn/catc/dir1/ff-shaker.pdf
[7] https://www3.epa.gov/ttn/catc/dir1/ff-pulse.pdf
[8] https://www3.epa.gov/ttn/catc/dir1/ff-revar.pdf

between 90% and 99.9%.[9] Wet ESPs have the advantage of controlling some amount of condensable particulate matter. The collection plates in a dry ESP are periodically cleaned by a rapper or hammer that sends a shock wave that knocks the collected particulate off the plate. Dry ESPs typically control streams with inlet grain loading values of 0.5 – 5 gr/ft^3 and have control efficiencies between 99% and 99.9%.[10] The Department considers ESP a technically feasible control technology for the industrial coal-fired boilers.

(c) Wet Scrubbers
Wet scrubbers use a scrubbing solution to remove $PM/PM_{10}/PM_{2.5}$ from exhaust gas streams. The mechanism for particulate collection is impaction and interception by water droplets. Wet scrubbers are configured as counter-flow, cross-flow, or concurrent flow, but typically employ counter-flow where the scrubbing fluid is in the opposite direction as the gas flow. Wet scrubbers have control efficiencies of 50% - 99%.[11] One advantage of wet scrubbers is that they can be effective on condensable particulate matter. A disadvantage of wet scrubbers is that they consume water and produce water and sludge. For fine particulate control, a venturi scrubber can be used, but typical loadings for such a scrubber are 0.1-50 grains/scf. The Department considers the use of wet scrubbers a technically feasible control technology for the industrial coal-fired boilers.

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

(e) Settling Chamber
Settling chambers appear only in the biomass fired boiler RBLC inventory for particulate control, not in the coal-fired boiler RBLC inventory. This type of technology is a part of

[9] https://www3.epa.gov/ttn/catc/dir1/fwespwpi.pdf
https://www3.epa.gov/ttn/catc/dir1/fwespwpl.pdf

[10] https://www3.epa.gov/ttn/catc/dir1/fdespwpi.pdf
https://www3.epa.gov/ttn/catc/dir1/fdespwpl.pdf

[11] https://www3.epa.gov/ttn/catc/dir1/fcondnse.pdf
https://www3.epa.gov/ttn/catc/dir1/fiberbed.pdf
https://www3.epa.gov/ttn/catc/dir1/fventuri.pdf

the group of air pollution control collectively referred to as "pre-cleaners" because the units are often used to reduce the inlet loading of particulate matter to downstream collection devices by removing the larger, abrasive particles. The collection efficiency of settling chambers is typically less than 10 percent for PM_{10}. The EPA fact sheet does not include a settling chamber collection efficiency for $PM_{2.5}$. The Department does not consider settling chambers a technically feasible control technology for the industrial coal-fired boilers.

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

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

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

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

Step 4 - Evaluate the Most Effective Controls

Fort Wainwright BACT Proposal

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

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

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

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 be controlled by maintaining good combustion practices at all times the units are in operation;

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

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

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

Table 4-2. Comparison of $PM_{2.5}$ BACT for Coal-Fired Boilers at Nearby Power Plants

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

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

Possible $PM_{2.5}$ emission control technologies for diesel-fired boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 13.220, Commercial/Institutional Size Boilers (<100 MMBtu/hr). The search results for diesel-fired boilers are summarized in Table 4-3.

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

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

RBLC Review

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

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

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

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

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

(b) Limited Operation
Limiting the operation of emission units reduces the potential to emit for those units. The Department considers limited operation a technically feasible control technology for the diesel-fired boilers.

(c) Good Combustion Practices
The theory of GCPs was discussed in detail in the $PM_{2.5}$ BACT section for the industrial coal-fired boilers and will not be repeated here. Proper management of the combustion process will result in a reduction of $PM_{2.5}$ emissions. The Department considers GCPs a technically feasible control technology for the diesel-fired boilers.

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

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

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

Step 4 - Evaluate the Most Effective Controls

Fort Wainwright BACT Proposal

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

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

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

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

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

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

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

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

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

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

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

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

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

Possible $PM_{2.5}$ emission control technologies for large engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 17.100-17.190, Large Internal Combustion Engines (>500 hp). The search results for large diesel-fired engines are summarized in Table 4-5.

Table 4-5. RBLC Summary of $PM_{2.5}$ Control for Large Diesel-Fired Engines

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

RBLC Review

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

[15] Emission factor from AP-42 Table's 1.3-2 (total condensable particulate matter from No. 2 oil, 1.3 lb/1,000 gal) and 1.3-7 ($PM_{2.5}$ size-specific factor from distillate oil, 0.83 lb/1,000 gal) converted to lb/MMBtu. Note that the E.F. has been corrected from the previous SIP because the small boilers are considered "commercial" under Table 1.3-7 and not "industrial" under Table 1.3-6.

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

(a) Diesel Particulate Filter (DPF)
DPFs are a control technology that are designed to physically filter particulate matter from the exhaust stream. Several designs exist which require cleaning and replacement of the filter media after soot has become caked onto the filter media. Regenerative filter designs are also available that burn the soot on a regular basis to regenerate the filter media. The Department considers DPF a technically feasible control technology for the large diesel-fired engines.

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

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

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

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

(f) Federal Emission Standards
The NSPS in 40 C.F.R. 60 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 that are subject to Subpart IIII.

(g) Limited Operation
FWA EUs 11, 12, and 13 currently operate under a combined annual limit of less than 600 hours per year to avoid classification as a PSD major modification for NOx. Limiting the operation of emissions units reduces the potential to emit of those units. The Department considers limited operation a technically feasible control technology for the large diesel-fired engines.

(h) Good Combustion Practices
The theory of GCPs was discussed in detail in the $PM_{2.5}$ BACT section for the coal-fired boilers and will not be repeated here. Proper management of the combustion process will result in a reduction of $PM_{2.5}$ emissions. The Department considers GCPs a technically feasible control technology for the large diesel-fired engine.

Step 2 - Eliminate Technically Infeasible $PM_{2.5}$ Control Technologies for the Large Engines
All control technologies identified are technically feasible to control particulate emissions from the large diesel-fired engines.

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

(g)	Limited Operation	(94% Control)
(a)	Diesel Particulate Filters	(85% Control)
(h)	Good Combustion Practices	(Less than 40% Control)
(b)	Diesel Oxidation Catalyst	(30% Control)
(e)	Low Ash Diesel	(25% Control)
(c)	Positive Crankcase Ventilation	(10% Control)
(f)	Federal Emission Standards	(Baseline)

Step 4 - Evaluate the Most Effective Controls

Fort Wainwright BACT Proposal

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

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

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

(c) Combust only ULSD.

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

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

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

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

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

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

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

(d) Combust only ULSD;

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

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

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

Location	EU	Year	Description	Size	Status	BACT Limit	Proposed BACT
DU	8	2009	Generator Engine	2,937 hp	Certified Engine	0.19 g/hp-hr	40 CFR 60 Subpart IIII
FWA	11	2003	Caterpillar 3512	1,206 hp	AP-42 Table 3.4-1	0.32 g/hp-hr	Limit combined operation to 600 hours per 12-month rolling period.
FWA	12	2003	Caterpillar 3512	1,206 hp	AP-42 Table 3.4-1	0.32 g/hp-hr	
FWA	13	2003	Caterpillar 3512	1,206 hp	AP-42 Table 3.4-1	0.32 g/hp-hr	
FWA	51	2010	Generator Engine	762 hp	Certified Engine	0.15 g/hp-hr	40 CFR 60 Subpart IIII
FWA	50	2010	Generator Engine	762 hp	Certified Engine	0.15 g/hp-hr	40 CFR 60 Subpart IIII
FWA	53	2008	Generator Engine	587 hp	Certified Engine	0.15 g/hp-hr	40 CFR 60 Subpart IIII
FWA	54	2005	Generator Engine	1,059 hp	AP-42 Table 3.4-1	0.32 g/hp-hr	Good Combustion Practices

Table 4-7 lists the proposed $PM_{2.5}$ BACT determination for this facility along with those for other diesel-fired engines rated at more than 500 hp located in the Serious $PM_{2.5}$ nonattainment area.

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

Facility	Process Description	Capacity	Limitation	Control Method
UAF	Large Diesel-Fired Engines	> 500 hp	0.05 - 0.32 g/hp-hr	Positive Crankcase Ventilation Ultra-Low Sulfur Diesel Limited Operation
Fort Wainwright	8 Large Diesel-Fired Engines	> 500 hp	0.15 – 0.32 g/hp-hr	Limited Operation Ultra-Low Sulfur Diesel Federal Emission Standards
GVEA North Pole	Large Diesel-Fired Engine	600 hp	0.32 g/hp-hr	Positive Crankcase Ventilation Good Combustion Practices
GVEA Zehnder	2 Large Diesel-Fired Engines	11,000 hp (each)	0.32 g/hp-hr	Limited Operation Good Combustion Practices

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

Possible $PM_{2.5}$ emission control technologies for small engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 17.210, Small Internal Combustion Engines (<500 hp). The search results for diesel-fired engines are summarized in Table 4-8.

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

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

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

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

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

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

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

(d) Federal Emission Standards
The theory behind federal emission standards was discussed in detail in the $PM_{2.5}$ BACT section for the large diesel-fired engines and will not be repeated here. The Department

considers federal emission standards a technically feasible control technology for the small diesel-fired engines.

(e) Limited Operation
Limiting the operation of emission units reduces the potential to emit for those units. The Department considers limited operation a technically feasible control technology for the small diesel-fired engines.

(f) Good Combustion Practices
The theory of GCPs was discussed in detail in the $PM_{2.5}$ BACT section for the coal-fired boilers and will not be repeated here. Proper management of the combustion process will result in a reduction of $PM_{2.5}$ emissions. The Department considers GCPs a technically feasible control technology for the small diesel-fired engines.

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

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

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

Step 4 - Evaluate the Most Effective Controls

Fort Wainwright BACT Proposal

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

(a) Limited Operation

(b) Good Combustion Practices;

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

(d) Combust only ULSD.

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

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

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

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

(a) Combust only ULSD;

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

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

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

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

Location	EU	Year	Description	Size	Status	BACT Limit	Proposed BACT
DU	9	1988	Generator Engine	353 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	Limited Operation for Non-Emergency Use (100 hours per year each) Good Combustion Practices Combust ULSD
DU	14	2008	Generator Engine	320 hp	Certified Engine	0.25 g/kW-hr	
DU	22	1989	Generator Engine	35 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
DU	23	2003	Generator Engine	155 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
DU	29a	2015	Emergency Generator Engine	74 hp	Certified Engine	0.3 g/hp-hr	
DU	30a	2018	Emergency Generator Engine	91 hp	Certified Engine	0.5 g/kW-hr	
DU	31a	2015	Emergency Generator Engine	74 hp	Certified Engine	0.3 g/hp-hr	
DU	32a	2018	Emergency Generator Engine	91 hp	Certified Engine	0.5 g/kW-hr	
DU	33a	2015	Emergency Generator Engine	75 hp	Certified Engine	0.5 g/kW-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	0.5 g/kW-hr	
DU	36a	2024	Emergency Generator Engine	161 hp	Certified Engine	0.375 g/kW-hr	
DU	37	2015	Emergency Generator Engine	75 hp	Certified Engine	0.5 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	

Location	EU	Year	Description	Size	Status	BACT Limit	Proposed BACT
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	60a	2023	Generator Engine	230 hp	Certified Engine	0.2 g/kW-hr	
FWA	61	1993	Generator Engine	50 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
FWA	62	2011	Generator Engine	18 hp	Certified Engine	0.4 g/kW-hr	
FWA	63	2003	Generator Engine	68 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
FWA	64	2010	Generator Engine	274 hp	Certified Engine	0.2 g/kW-hr	
FWA	65	2010	Generator Engine	274 hp	Certified Engine	0.2 g/kW-hr	
FWA	66	2014	Generator Engine	235 hp	Certified Engine	0.2 g/kW-hr	
FWA	67	2016	Generator Engine	67 hp	Certified Engine	0.4 g/kW-hr	
FWA	68	2017	Generator Engine	324 hp	Certified Engine	0.2 g/kW-hr	
FWA	69	2023	Generator Engine	86 hp	Certified Engine	0.4 g/kW-hr	

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

Table 4-10. Comparison of $PM_{2.5}$ BACT for Small Engines at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
Fort Wainwright	Small Diesel-Fired Engines	< 500 hp	0.015 – 1.0 g/hp-hr	Good Combustion Practices Limited Operation
UAF	Small Diesel-Fired Engines	< 500 hp	**<u>0.023</u>** – 1.0 g/hp-hr	Good Combustion Practices Limited Operation

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

Possible $PM_{2.5}$ emission control technologies for material handling were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 99.100 - 190, Fugitive Dust Sources. The search results for material handling units are summarized in Table 4-11.

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

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

RBLC Review

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

Step 1 - Identification of $PM_{2.5}$ Control Technology for the Material Handling
From research, the Department identified the following technologies as available for $PM_{2.5}$ control of materials handling:

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

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

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

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

(e) Mechanical Collectors (Cyclones)
The theory behind cyclones was discussed in detail in the $PM_{2.5}$ BACT section for the industrial coal-fired boilers and will not be repeated here. Except for storage piles, 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. The Department does not consider wind screens a technically feasible control technology for the material handling units located in enclosures.

(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 located in enclosures.

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 as noted in Step 1.

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) $PM_{2.5}$ 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 fugitive dust control plan identified in the applicable operating permit issued to the source in accordance with 18 AAC 50 and AS 46.14. However, based on the comments received from Doyon in response to the proposed SIP amendments, and further review of past full compliance evaluations where PM emissions were evaluated, the Department determined that the following practices are better suited to control PM2.5 emission from EU 52: Wind Awareness, Compaction, Water Suppression as necessary, and snow cover as applicable.

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

The Department's finding is that BACT for $PM_{2.5}$ emissions from the material handling equipment is as follows:

(a) $PM_{2.5}$ emissions from the material handling equipment shall be controlled by operating the South and North Coal Handling Systems and the Underbunker Conveyors , and the Fly and Bottom Ash Handling Systems EUs, with enclosed conveying systems equipped with dust collectors, EUs 7a through 7c, 51a, and 51b, 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 dust collectors DU EUs 7a, 7b, 7c, 51a, and 51b shall be demonstrated by following the manufacturer's operating and maintenance procedures at all times of operation.

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

EU ID	Description	Current Control	BACT Limit	Proposed BACT Control
7a	South Coal Handling Dust Collector	Partial Enclosure and Dust Collection	0.0025 gr/dscf	Enclosed emission points and follow manufacturer recommendations for operations and maintenance
7b	South Underbunker Dust Collector	Partial Enclosure and Dust Collection	0.02 gr/dscf	Enclosed emission points and follow manufacturer recommendations for operations and maintenance
7c	North Coal Handling Dust Collector	Partial Enclosure and Dust Collection	0.02 gr/dscf	Enclosed emission points and limited Operation – This source serves as backup to EU 7a and operates less than 200 hours each year
52	Emergency Coal Storage Pile and Operations	Follow Fugitive Dust Control Plan	Dust Control Plan[16]	Wind Awareness, Compaction, Water Suppression as necessary, and snow cover as applicable
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

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

5. 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 and Doyon Utilities, LLC 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/Wet Flue Gas Desulfurization (WFGD)

Post combustion flue gas desulfurization techniques can remove SO_2 formed during combustion by using an alkaline reagent to absorb SO_2 in the flue gas. Flue gasses can be treated using wet, dry, or semi-dry desulfurization processes. In the wet scrubbing system, flue gas is contacted with a solution or slurry of alkaline material in a vessel providing a relatively long residence time. The SO_2 in the flue reacts with the alkali solution or slurry by adsorption and/or absorption mechanisms to form liquid-phase salts. These salts are dried to about one percent free moisture by the heat in the flue gas. These solids are entrained in the flue gas and carried from the dryer to a PM collection device, such as a baghouse.

The lime and limestone wet scrubbing process uses a slurry of calcium oxide or limestone to absorb SO_2 in a wet scrubber. Control efficiencies in excess of 91 percent for lime and 94 percent for limestone over extended periods are possible. Sodium scrubbing processes generally employ a wet scrubbing solution of sodium hydroxide or sodium carbonate to absorb SO_2 from the flue gas. Sodium scrubbers are generally limited to smaller sources because of high reagent costs and can have SO_2 removal efficiencies of up to 96.2 percent. The double or dual alkali system uses a clear sodium alkali solution for SO_2

removal followed by a regeneration step using lime or limestone to recover the sodium alkali and produce a calcium sulfite and sulfate sludge. SO_2 removal efficiencies of 90 to 96 percent are possible. The Department considers flue gas desulfurization with a wet scrubber a technically feasible control technology for the industrial coal-fired boilers.

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

(c) Dry Sorbent Injection (DSI)
Dry sorbent injection systems (spray dry scrubbers) pneumatically inject a powdered sorbent directly into the furnace, the economizer, or the downstream ductwork depending on the temperature and the type of sorbent utilized. The dry waste is removed using a baghouse or electrostatic precipitator. Spray drying technology is less complex mechanically, and no more complex chemically, than wet scrubbing systems. The main advantages of the spray dryer is that this technology avoids two problems associated with wet scrubbing, corrosion and liquid waste treatment. Spray dry scrubbers are mostly used for small to medium capacity boilers and are preferable for retrofits. The Department considers flue gas desulfurization with a dry scrubber a technically feasible control technology for the industrial coal-fired boilers.

(d) Low Sulfur Coal
Fort Wainwright purchases coal from the Usibelli Coal Mine located in Healy, Alaska. This coal mine is located 115 miles south of Fairbanks. The coal mined at Usibelli is sub-bituminous coal and has a relatively low sulfur content with guarantees of less than 0.4 percent by weight. Usibelli Coal Data Sheets indicate a range of 0.08 to 0.28 percent Gross As Received (GAR) percent Sulfur (%S). According to the U.S. Geological Survey, coal with less than one percent sulfur is classified as low sulfur coal. The Department considers the use of low sulfur coal a feasible control technology for the industrial coal-fired boilers. Because the Permittee already combusts low sulfur coal, this control option represents the baseline emissions rate, or a 0% emissions control.

(e) Good Combustion Practices
The theory of GCPs was discussed in detail in the $PM_{2.5}$ BACT section for the industrial coal-fired boilers and will not be repeated here. Proper management of the combustion process will result in a reduction of SO_2 emissions. The Department considers GCPs a technically feasible control technology for the industrial coal-fired boilers.

(f) Circulating Dry Scrubber (CDS)
This demonstrated technology can achieve SO_2 removal rates comparable to wet flue gas desulfurization (FGD). CDS technology utilizes a dry circulating fluid bed and an ESP or Fabric Filter for utility scale flue gas desulfurization. CDS technology lends well for small footprints and adequate SO_2 removal. CDS technology is designed for relatively

small installations with limited space and perform well with medium-high sulfur coals. The Department considers CDS a technically feasible control technology for the industrial coal-fired boilers.

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

Step 3 - Rank the Remaining SO_2 Control Technologies for Industrial Coal-Fired Boilers
The following control technologies have been identified and ranked by efficiency[17] for control of SO_2 emissions from the industrial coal-fired boilers:

(a) Wet Scrubbers (WFGD) (93% Control)
(b) Dry Sorbent Injection (Duct Sorbent Injection) (93% Control)
(c) Circulating Dry Scrubber (88% Control)
(d) Spray Dry Absorbers (SDA) (88% Control)
(e) Good Combustion Practices (Less than 40% Control)
(f) Low Sulfur Coal (0% Control, Baseline)

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

Step 4 - Evaluate the Most Effective Controls

DU BACT Proposal

DU provided an updated economic analysis from Black and Veatch on November 13, 2023, for addressing WFGD (caustic and limestone), SDA, CDS, and DSI control technology systems. This updated analysis also included new removal efficiencies for DSI based on information from BACT Process Systems, Inc. and United Conveyor, LLC. The November 13, 2023 analysis applies a 93% removal rate for DSI, which is the same control efficiency as WFGD. The SO_2 removal rates for the CDS and SDA control systems are less than 93 percent. SDA and CDS also have higher capital costs than the other technologies considered. A summary of the DU analysis is shown below in Table 5-2.

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

Control Alternative	Potential to Emit (tpy)	Control Efficiency (%)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annual Costs ($/year)	Cost Effectiveness ($/ton)
WFGD - Caustic	101	93	1,369	110,262,000	18,832,000	13,755

[17] In ranking the different control efficiencies, the Department used Black and Veatch vendor data provided by DU for the coal-fired boilers in a document titled, "CHPP SO_2 Reduction Analysis Addendum, 7 November 2023."

Control Alternative	Potential to Emit (tpy)	Control Efficiency (%)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annual Costs ($/year)	Cost Effectiveness ($/ton)
WFGD - limestone	101	93	1,369	126,374,000	19,474,000	14,224
Dry Sorbent Injection	101	93	1,369	28,424,000	9,082,000	6,636
Spray-Dry Adsorption	176	88	1,293	166,101,000	22,812,000	17,638
CDS	176	88	1,293	196,447,000	27,096,000	20,950
Capital Recovery Factor = 0.0931 (8.5% interest rate for a 30-year equipment life)						

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

DU 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 operation of dry sorbent injection system(s).

(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 0.04 lb/MMBtu.

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

Department Evaluation of BACT for SO_2 Emissions from the Industrial Coal-Fired Boilers

The Department did not revise the cost analysis provided on November 13, 2023 by DU because we find that the economic analysis conducted by Black & Veatch is reasonable to determine cost effectiveness of each potential technology for SO_2 Emissions reduction. It is possible that costs for an individual control technology could be slightly lower or higher, but that would not change the overall finding that DSI with a 93% SO_2 removal rate is cost effective and the other control technologies will cost substantially more while returning little to no added reductions of SO_2. The Department analysis is unchanged from the DU analysis presented in Table 5-2 above and is presented in Table 5-3.

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

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annual Costs ($/year)	Cost Effectiveness ($/ton)
WFGD - Caustic	101	1369	110,262,000	18,832,000	13,755
WFGD - limestone	101	1369	126,374,000	19,474,000	14,224
Spray-Dry Adsorption	176	1293	166,101,000	22,812,000	17,638

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annual Costs ($/year)	Cost Effectiveness ($/ton)
CDS	176	1293	196,447,000	27,096,000	20,950
Dry Sorbent Injection	101	1369	28,424,000	9,082,000	6,636
Capital Recovery Factor = 0.0931 (8.5% interest rate for a 30-year equipment life)					

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

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

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

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

(b) SO_2 emissions from DU EUs 1 through 6 shall not exceed 0.04 lb/MMBtu[18] 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

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[19]
Fort Wainwright	6 Coal-Fired Boilers	1380 MMBtu/hr (combined)	0.04 lb/MMBtu[18]	Dry Sorbent Injection Limited Operation
UAF	Dual Fuel-Fired Boiler	295.6 MMBtu/hr	0.10 lb/MMBtu[20]	Fluidized Bed Limestone Injection
Chena	4 Coal-Fired Boilers	497 MMBtu/hr (combined)	0.301 lb/MMBtu[21]	Good Combustion Practices

5.2 SO_2 BACT for the Diesel-Fired Boilers

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

[18] BACT limit is a vendor emissions guarantee.

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

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

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

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

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

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

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

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

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

(b) Limited Operation
Limiting the operation of emission units reduces the potential to emit for those units. The Department considers limited operation a technically feasible control technology for the diesel-fired boilers.

(c) Good Combustion Practices
The theory of GCPs was discussed in detail in the $PM_{2.5}$ BACT section for the coal-fired boilers and will not be repeated here. Proper management of the combustion process will result in a reduction of SO_2 emissions. The Department considers GCPs a technically feasible control technology for the diesel-fired boilers.

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

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

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

Step 4 - Evaluate the Most Effective Controls

Fort Wainwright BACT Proposal

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

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

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

(c) Combust only ULSD.

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

The Department reviewed Fort Wainwright's proposal and finds that the four significant sized boilers[22] have a combined PTE of less than 9 tpy for SO_2 using the conservative assumption of 0.3 percent sulfur by weight in fuel oil. Fort Wainwright proposed combusting only ULSD in all the boilers, therefore an economic analysis is not required.

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

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

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

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

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

Table 5-6 lists the proposed SO_2 BACT determination for this facility along with those for other diesel-fired boilers rated at less than 100 MMBtu/hr in the Serious $PM_{2.5}$ nonattainment area.

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

Facility	Process Description	Capacity	Limitation	Control Method
Fort Wainwright	4 Diesel-Fired Boilers	< 100 MMBtu/hr	15 ppmw S in fuel	Good Combustion Practices Ultra-Low Sulfur Diesel
UAF	6 Diesel-Fired Boilers	< 100 MMBtu/hr	15 ppmw S in fuel	Good Combustion Practices Ultra-Low Sulfur Diesel
GVEA Zehnder	2 Diesel-Fired Boilers	< 100 MMBtu/hr	15 ppmw S in fuel	Good Combustion Practices Ultra-Low Sulfur Diesel

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

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

Possible SO_2 emission control technologies for large engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 17.100 to 17.190, Large Internal Combustion Engines (>500 hp). The search results for large diesel-fired engines are summarized in Table 5-7.

Table 5-7. RBLC Summary for SO_2 Control for Large Diesel-Fired Engines

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

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

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

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

(b) Federal Emission Standards
The NSPS 40 C.F.R. 60 Subpart IIII applies to stationary compression ignition internal combustion engines that are manufactured or reconstructed after July 11, 2005. The Department considers meeting the technology based NSPS of Subpart IIII as a technically feasible control technology for the large diesel-fired engines that are subject to Subpart IIII.

(c) Limited Operation
FWA EUs 11, 12, and 13 currently operate under a combined annual limit of less than 600 hours per year to avoid classification as a PSD major modification for NOx. Limiting the operation of emission units reduces the potential to emit for those units. The Department considers limited operation a technically feasible control technology for the large diesel-fired engines.

(d) Good Combustion Practices
The theory of GCPs was discussed in detail in the $PM_{2.5}$ BACT section for the coal-fired boilers and will not be repeated here. Proper management of the combustion process will

result in a reduction of SO_2 emissions. The Department considers GCPs a technically feasible control technology for the large diesel-fired engines.

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

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

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

Step 4 - Evaluate the Most Effective Controls

Fort Wainwright BACT Proposal

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

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

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

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

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

Step 5 - Selection of SO_2 BACT for the Large Diesel-Fired Engines
The Department's finding is that BACT for SO_2 emissions from the large diesel-fired engines is as follows:

(a) SO_2 emissions from DU EU 8, and FWA EUs 11, 12, 13, and 50 through 54 shall be controlled by only combusting ULSD;

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

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

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

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

Table 5-8 lists the proposed SO_2 BACT determination for this facility along with those for other diesel-fired engines rated at more than 500 hp located in the Serious $PM_{2.5}$ nonattainment area.

Table 5-8. Comparison of SO_2 BACT for Large Diesel-Fired Engines at Nearby Power Plants

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

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

Possible SO_2 emission control technologies for small engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 17.210, Small Internal Combustion Engines (<500 hp). The search results for small diesel-fired engines are summarized in Table 5-9.

Table 5-9. RBLC Summary for SO_2 Control for Small Diesel-Fired Engines

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

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

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

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

(b) Limited Operation
Limiting the operation of emission units reduces the potential to emit for those units. The Department considers limited operation a technically feasible control technology for the small diesel-fired engines.

(c) Good Combustion Practices
The theory of GCPs was discussed in detail in the $PM_{2.5}$ BACT section for the coal-fired boilers and will not be repeated here. Proper management of the combustion process will result in a reduction of SO_2 emissions. The Department considers GCPs a technically feasible control technology for the small diesel-fired engines.

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

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

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

Step 4 - Evaluate the Most Effective Controls

Fort Wainwright BACT Proposal

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

(a) Good Combustion Practices;

(b) Combust only ULSD.

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

The Department reviewed Fort Wainwright's proposal and found that in addition to maintaining good combustion practices and combusting only ULSD, limiting operation of the small diesel-fired engines during non-emergency operation to no more than 100 hours per year each is BACT for SO_2.

Step 5 - Selection of SO_2 BACT for the Small Diesel-Fired Engines
The Department's finding is that BACT for SO_2 emissions from the small diesel-fired engines is as follows:

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

(b) Combust only ULSD; and

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

Table 5-10 lists the proposed SO_2 BACT determination for this facility along with those for other diesel-fired engines rated at less than 500 hp located in the Serious $PM_{2.5}$ nonattainment area.

Table 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	Small Diesel-Fired Engines	< 500 hp	15 ppmw S in fuel	Limited Operation Ultra-Low Sulfur Diesel Good Combustion Practices
UAF	Small Diesel-Fired Engines	< 500 hp	15 ppmw S in fuel	Limited Operation Ultra-Low Sulfur Diesel Good Combustion Practices

6. BACT DETERMINATION SUMMARY

Table 6-1. Proposed NOx BACT Limits

EU ID	Description	Capacity	Proposed BACT Limit	Proposed BACT Control
All	N/A	N/A	None EPA approved a comprehensive precursor demonstration for NOx	

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

EU ID	Description	Capacity	Proposed BACT Limit	Proposed BACT Control
DU 1	Coal-Fired Boiler 3	230 MMBtu/hr	0.045 lb/MMBtu	Full stream baghouse Good Combustion Practices
DU 2	Coal-Fired Boiler 4	230 MMBtu/hr	0.045 lb/MMBtu	
DU 3	Coal-Fired Boiler 5	230 MMBtu/hr	0.045 lb/MMBtu	
DU 4	Coal-Fired Boiler 6	230 MMBtu/hr	0.045 lb/MMBtu	
DU 5	Coal-Fired Boiler 7	230 MMBtu/hr	0.045 lb/MMBtu	
DU 6	Coal-Fired Boiler 8	230 MMBtu/hr	0.045 lb/MMBtu	
FWA 8	Backup Diesel-Fired Boiler 1	19 MMBtu/hr	**0.016** lb/MMBtu	Good Combustion Practices Limited Operation (600 hours/year combined)
FWA 9	Backup Diesel-Fired Boiler 2	19 MMBtu/hr	**0.016** lb/MMBtu	
FWA 10	Backup Diesel-Fired Boiler 3	19 MMBtu/hr	**0.016** lb/MMBtu	
FWA 40	Diesel-Fired Boiler	2.6 MMBtu/hr	0.016 lb/MMBtu	Good Combustion Practices
DU 8	Generator Engine	2,937 hp	0.19 g/hp-hr	Combust ULSD Good Combustion Practices Limited Operation (500 hours/yr)
FWA 50	Generator Engine	762 hp	0.15 g/hp-hr	
FWA 51	Generator Engine	762 hp	0.15 g/hp-hr	
FWA 53	Generator Engine	587 hp	0.15 g/hp-hr	

EU ID	Description	Capacity	Proposed BACT Limit	Proposed BACT Control
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 (100 hours/year each, for non-emergency operation) Good Combustion Practices Combust ULSD
DU 14	Generator Engine	320 hp	0.25 g/kW-hr	
DU 22	Generator Engine	35 hp	2.20 E-3 lb/hp-hr	
DU 23	Generator Engine	155 hp	2.20 E-3 lb/hp-hr	
FWA 52	Generator Engine	82 hp	2.20 E-3 lb/hp-hr	
FWA 55	Generator Engine	212 hp	2.20 E-3 lb/hp-hr	
FWA 56	Generator Engine	176 hp	0.40 g/hp-hr	
FWA 57	Generator Engine	212 hp	2.20 E-3 lb/hp-hr	
FWA 58	Generator Engine	71 hp	0.4 g/kW-hr	
FWA 59	Generator Engine	35 hp	2.20 E-3 lb/hp-hr	
FWA 60a	Generator Engine	230 hp	0.2 g/kW-hr	
FWA 61	Generator Engine	50 hp	2.20 E-3 lb/hp-hr	
FWA 62	Generator Engine	18 hp	0.4 g/kW-hr	
FWA 63	Generator Engine	68 hp	2.20 E-3 lb/hp-hr	
FWA 64	Generator Engine	274 hp	0.2 g/kW-hr	
FWA 65	Generator Engine	274 hp	0.2 g/kW-hr	
FWA 66	Generator Engine	235 hp	0.2 g/kW-hr	
FWA 67	Generator Engine	67 hp	0.4 g/kW-hr	
FWA 68	Generator Engine	324 hp	0.2 g/kW-hr	
FWA 69	Generator Engine	86 hp	0.4 g/kW-hr	
DU 34	Well Pump Engine	220 hp	2.20 E-3 lb/hp-hr	
DU 35	Well Pump Engine	55 hp	0.5 g/kW-hr	

EU ID	Description	Capacity	Proposed BACT Limit	Proposed BACT Control
DU 36a	Emergency Generator Engine	161 hp	0.375 g/kW-hr	Limited Operation (100 hours/year each, for non-emergency operation) Good Combustion Practices Combust ULSD
DU 29a	Emergency Generator Engine	74 hp	0.3 g/hp-hr	
DU 30a	Emergency Generator Engine	91 hp	0.5 g/kW-hr	
DU 31a	Emergency Generator Engine	74 hp	0.3 g/hp-hr	
DU 32a	Emergency Generator Engine	91 hp	0.5 g/kW-hr	
DU 33a	Emergency Generator Engine	75 hp	0.5 g/kW-hr	
DU 37	Emergency Generator Engine	75 hp	0.5 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	
FWA 34	DDFP-04AT	235 hp	2.20 E-3 lb/hp-hr	
FWA 35	N-855-F	240 hp	2.20 E-3 lb/hp-hr	
FWA 36	N-855-F	240 hp	2.20 E-3 lb/hp-hr	
FWA 37	JU4H-UF40	105 hp	2.20 E-3 lb/hp-hr	
FWA 38	PDFP-06YT	120 hp	2.20 E-3 lb/hp-hr	
FWA 39	PDFP-06YT	120 hp	2.20 E-3 lb/hp-hr	

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

EU ID	Description	Proposed BACT Limit	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	Wind Awareness, Compaction, Water Suppression as necessary, and snow cover as applicable
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	Coal-Fired Boiler 3	230 MMBtu/hr	0.04 lb/MMBtu	Dry Sorbent Injection[19] Limited Operation (336,000 tons/year combined)
DU 2	Coal-Fired Boiler 4	230 MMBtu/hr	0.04 lb/MMBtu	
DU 3	Coal-Fired Boiler 5	230 MMBtu/hr	0.04 lb/MMBtu	
DU 4	Coal-Fired Boiler 6	230 MMBtu/hr	0.04 lb/MMBtu	
DU 5	Coal-Fired Boiler 7	230 MMBtu/hr	0.04 lb/MMBtu	
DU 6	Coal-Fired Boiler 8	230 MMBtu/hr	0.04 lb/MMBtu	
FWA 8	Backup Diesel-Fired Boiler 1	19 MMBtu/hr	15 ppmv S in fuel	Good Combustion Practices Limited Operation (600 hours/year combined)
FWA 9	Backup Diesel-Fired Boiler 2	19 MMBtu/hr	15 ppmv S in fuel	
FWA 10	Backup Diesel-Fired Boiler 3	19 MMBtu/hr	15 ppmv S in fuel	
FWA 40	Diesel-Fired Boiler	2.6 MMBtu/hr	15 ppmv S in fuel	Good Combustion Practices Combust ULSD
DU 8	Generator Engine	2,937 hp	15 ppmv S in fuel	Good Combustion Practices Limited Operation (DU EU 8 – 500 hours/year) (FWA EU 50 – 54 -100 hours/year each, for non-emergency operation) Combust ULSD
FWA 50	Generator Engine	762 hp	15 ppmv S in fuel	
FWA 51	Generator Engine	762 hp	15 ppmv S in fuel	
FWA 53	Generator Engine	587 hp	0.15 g/hp-hr	
FWA 54	Generator Engine	1,059 hp	0.32 g/hp-hr	
FWA 11	Caterpillar 3512	1,206 hp	15 ppmv S in fuel	Limit Operation (600 hours/year combined) Combust ULSD Good Combustion Practices
FWA 12	Caterpillar 3512	1,206 hp	15 ppmv S in fuel	
FWA 13	Caterpillar 3512	1,206 hp	15 ppmv S in fuel	
DU 9	Generator Engine	353 hp	15 ppmv S in fuel	Limited Operation (100 hours/year each, for non-emergency operation) Good Combustion Practices 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	

EU ID	Description	Capacity	Proposed BACT Limit	Proposed BACT Control
FWA 56	Generator Engine	176 hp	15 ppmv S in fuel	Limited Operation (100 hours/year each, for non-emergency operation) Good Combustion Practices Combust ULSD
FWA 57	Generator Engine	212 hp	15 ppmv S in fuel	
FWA 58	Generator Engine	71 hp	15 ppmv S in fuel	
FWA 59	Generator Engine	35 hp	15 ppmv S in fuel	
FWA 60a	Generator Engine	230 hp	15 ppmv S in fuel	
FWA 61	Generator Engine	50 hp	15 ppmv S in fuel	
FWA 62	Generator Engine	18 hp	15 ppmv S in fuel	
FWA 63	Generator Engine	68 hp	15 ppmv S in fuel	
FWA 64	Generator Engine	274 hp	15 ppmv S in fuel	
FWA 65	Generator Engine	274 hp	15 ppmv S in fuel	
FWA 66	Generator Engine	235 hp	15 ppmv S in fuel	
FWA 67	Generator Engine	67 hp	15 ppmv S in fuel	
FWA 68	Generator Engine	324 hp	15 ppmv S in fuel	
FWA 69	Generator Engine	86 hp	15 ppmv S in fuel	
DU 34	Well Pump Engine	220 hp	15 ppmv S in fuel	
DU 35	Well Pump Engine	55 hp	15 ppmv S in fuel	
DU 36a	Emergency Generator Engine	161 hp	15 ppmv S in fuel	
DU 29a	Emergency Generator Engine	74 hp	15 ppmv S in fuel	
DU 30a	Emergency Generator Engine	91 hp	15 ppmv S in fuel	
DU 31a	Emergency Generator Engine	74 hp	15 ppmv S in fuel	
DU 32a	Emergency Generator Engine	91 hp	15 ppmv S in fuel	
DU 33a	Emergency Generator Engine	75 hp	15 ppmv S in fuel	
DU 37	Emergency Generator Engine	75 hp	15 ppmv S in fuel	
FWA 26	QSB7-G3 NR3	295 hp	15 ppmv S in fuel	
FWA 27	4024HF285B	67 hp	15 ppmv S in fuel	
FWA 28	CAT C9 GENSET	398 hp	15 ppmv S in fuel	
FWA 29	TM30UCM	47 hp	15 ppmv S in fuel	
FWA 30	JW64-UF30	275 hp	15 ppmv S in fuel	
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	

EU ID	Description	Capacity	Proposed BACT Limit	Proposed BACT Control
FWA 35	N-855-F	240 hp	15 ppmv S in fuel	Limited Operation (100 hours/year each, for non-emergency operation) Good Combustion Practices Combust ULSD
FWA 36	N-855-F	240 hp	15 ppmv S in fuel	
FWA 37	JU4H-UF40	105 hp	15 ppmv S in fuel	
FWA 38	PDFP-06YT	120 hp	15 ppmv S in fuel	
FWA 39	PDFP-06YT	120 hp	15 ppmv S in fuel	

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

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

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

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

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

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

Good Combustion Practices	• Perform regular maintenance according to the manufacturer's and the operator's maintenance requirements and procedures. • Keep records of maintenance conducted on emission units to comply with this BACT measure. • Keep a copy of the manufacturer's and the operator's recommended maintenance procedures. • Report a summary of the maintenance records.

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

Pollutant of Concern: SO_2	
BACT Measure	**Monitoring, Recordkeeping and Reporting Requirements** [1]
Combust Only Ultra Low Sulfur fuel at no more than 0.0015 percent sulfur by weight	• For each shipment of fuel, test the sulfur content or keep receipts that specify fuel grade, date and time, and quantity of fuel received. Keep records of the results of sulfur content tests and receipts for fuel shipments. • Include a summary of fuel test results and shipping receipts for the reporting period in each semi-annual operating report.
Good Combustion Practices	• For DU EU ID 8 and FWA EU IDs 11, 12, 13, 50, 51, 53, and 54: o Perform regular maintenance according to the manufacturer's and the operator's maintenance procedures. o Keep records of any maintenance that would have a significant effect on emissions. o Keep a copy of either the manufacturer's or the operator's maintenance procedures. o Report a summary of the maintenance records.
Limit DU EU 8 to 500 hours/yr	• Demonstrate compliance by complying with Condition 6.1.b of Minor Permit AQ1121MS04 Rev. 1.
Limit FWA EU 11, 12 and 13 combined hours to 600 hours/yr	• Maintain and operate a non-resettable hour meter on each engine, capable of recording the total hours of operation. • By the end of each calendar month, record the total operating hours of each EU and the EUs combined for the previous calendar month and for the previous 12 consecutive months. • Report the operating records for each engine.
Limit maintenance checks, readiness testing, and non-emergency operation of FWA EUs 50, 51, 53, and 54 to 100 hours/yr each	• Maintain and operate a non-resettable hour meter on each engine, capable of recording the total hours of operation. • By the end of each calendar month, record the total operating hours of the EU for the previous calendar month and for the previous 12 consecutive months. • Report the operating records for each engine.

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

Pollutant of Concern: SO_2	
BACT Measure	**Monitoring, Recordkeeping and Reporting Requirements** [1]
Combust Only Ultra Low Sulfur fuel at no more than 0.0015 percent sulfur by weight	• For each shipment of fuel, test sulfur content or keep receipts that specify fuel grade, date and time, and quantity of fuel received. Keep records of the results of sulfur content tests and receipts for fuel shipments. • Include a summary of fuel test results and shipping receipts for the reporting period in each semi-annual operating report.
Limit the maintenance checks, readiness testing, and non-emergency operation of each EU to 100 hours per year each	• Maintain and operate a non-resettable hour meter, capable of recording the total hours of operation. • By the end of each calendar month, record the total operating hours of the EU for the previous calendar month and for the previous 12 consecutive months. • Report the operating hour records for each engine.
Good Combustion Practices	• Perform regular maintenance considering the manufacturer's or the operator's maintenance procedures. • Keep records of any maintenance that would have a significant effect on emissions. The records may be kept in electronic format. • Keep a copy of either the manufacturer's or the operator's maintenance procedures. • Report a summary of the maintenance records collected.

DEPARTMENT OF ENVIRONMENTAL CONSERVATION
AIR QUALITY CONTROL MINOR PERMIT

Minor Permit: **AQ0236MSS03 Revision 2** **Final Date – October 28, 2024**
Rescinds Permit: AQ0236MSS03 Revision 1

The Alaska Department of Environmental Conservation (Department), under the authority of AS 46.14 and 18 AAC 50, issues Air Quality Control Minor Permit AQ0236MSS03 Revision 2 to the Permittee listed below.

Permittee:	**U.S. Army Garrison** ATTN: IMFW-ZA 1060 Gaffney Road #6000 Fort Wainwright, AK 99703-6000
Stationary Source:	**USAG Alaska Fort Wainwright**
Location:	NAD 1927 Latitude: 64.8345678 / Longitude: -147.61913
Project:	$PM_{2.5}$ Serious Nonattainment State Implementation Plan (SIP)
Permit Contact:	**Robert Larimore** Chief, Environmental Division (907) 361-4213 robert.k.larimore.civ@army.mil

The Permittee submitted an application for Minor Permit AQ0236MSS03 under AS 46.14.130(c)(2) because the Department found that public health or air quality effects provide a reasonable basis to regulate the stationary source. This finding is contained in the State Air Quality Control Plan adopted on November 19, 2019.

Minor Permit AQ0236MSS03 Revision 2 is issued to address comments from the U.S. EPA concerning State Implementation Plan requirements for particulate matter with an aerodynamic diameter of 2.5 microns or less ($PM_{2.5}$) limits and associated monitoring, recordkeeping, and reporting for EU IDs 8 through 10, 11 through 13, 26 through 40, 50 through 54, and 55 through 69 of the U.S. Army Garrison's Fort Wainwright stationary source.

This permit satisfies the obligation of the Permittee to obtain a minor permit under 18 AAC 50. As required by AS 46.14.120(c), the Permittee shall comply with the terms and conditions of this permit.

James R. Plosay, Manager
Air Permits Program

Table of Contents

Abbreviations and Acronyms

AAAQS ....Alaska Ambient Air Quality Standards
AAC....................Alaska Administrative Code
ADEC ....Alaska Department of Environmental Conservation
AOS ....Air Online Services
AS ....Alaska Statutes
ASTM ....American Society for Testing and Materials
BACM ....Best Available Control Measures
BACT ....best available control technology
bhp ....brake horsepower
CDX....................Central Data Exchange
CEDRI ....Compliance and Emissions Data Reporting Interface
C.F.R. ....Code of Federal Regulations
CAA....................Clean Air Act
CO ....carbon monoxide
Department ....Alaska Department of Environmental Conservation
dscf ....dry standard cubic foot
EPA ....US Environmental Protection Agency
EU.......................emissions unit
FWA ....Alaska Fort Wainright
gr/dscf.................grain per dry standard cubic foot (1 pound = 7000 grains)
gph ....gallons per hour
HAPs ....hazardous air pollutants [as defined in AS 46.14.990]
hp ....horsepower
ID........................emissions unit identification number
kPa ....kiloPascals
LAER..................lowest achievable emission rate
MACT ....maximum achievable control technology [as defined in 40 C.F.R. 63]
MMBtu/hr...........million British thermal units per hour
MMscf ....million standard cubic feet
MR&R ....monitoring, recordkeeping, and reporting
NAA ....Nonattainment area
NESHAPs............National Emission Standards for Hazardous Air Pollutants [as contained in 40 C.F.R. 61 and 63]
NO_x......................nitrogen oxides
NRE......................nonroad engine
NSPS ....New Source Performance Standards [as contained in 40 C.F.R. 60]
O & M ....operation and maintenance
O_2..........................oxygen
PAL ....plantwide applicability limitation
PM_{10} ....particulate matter less than or equal to a nominal 10 microns in diameter
$PM_{2.5}$.....................particulate matter less than or equal to a nominal 2.5 microns in diameter
ppm ....parts per million
ppmv, ppmvd........parts per million by volume on a dry basis
ppmw....................parts per million by weight
psia ....pounds per square inch (absolute)
PSD ....prevention of significant deterioration
PTE.......................potential to emit
SIC........................Standard Industrial Classification
SIP ....State Implementation Plan
SPC.......................Standard Permit Condition or Standard Operating Permit Condition
SO_2 ....sulfur dioxide
The Act.................Clean Air Act
TPH ....tons per hour
TPY ....tons per year
ULSD ....Ultra Low Sulfur Diesel
USAG...................United States Army Garrison
VOC ....volatile organic compound [as defined in 40 C.F.R. 51.100(s)]
VOL......................volatile organic liquid [as defined in 40 C.F.R. 60.111b, Subpart Kb]
vol% ....volume percent
wt% ....weight percent
wt%S_{fuel} ....weight percent of sulfur in fuel

Section 1 Emissions Unit Inventory

Emissions Unit (EU) Authorization. The Permittee is authorized to install and operate the EUs listed in Table 1 in accordance with the minor permit application and the terms and conditions of this permit. The information in Table 1 is for identification purposes only, unless otherwise noted in the permit. The specific EU descriptions do not restrict the Permittee from replacing an EU identified in Table 1.

Table 1 – EU Inventory

EU ID	Emissions Unit Name	Emissions Unit Description	Rating/Size	Installation or Construction Date
8	Backup Diesel-Fired Boiler 1	Bassett Hospital (Bldg 4076)	19 MMBtu/hr	Est. 2003-2004
9	Backup Diesel-Fired Boiler 2	Bassett Hospital (Bldg 4076)	19 MMBtu/hr	Est. 2003-2004
10	Backup Diesel-Fired Boiler 3	Bassett Hospital (Bldg 4076)	19 MMBtu/hr	Est. 2003-2004
11	Backup Diesel-Electric Generator 1	Bassett Hospital (Bldg 4076)	900 kW	Est. 2003-2004
12	Backup Diesel-Electric Generator 2	Bassett Hospital (Bldg 4076)	900 kW	Est. 2003-2004
13	Backup Diesel-Electric Generator 3	Bassett Hospital (Bldg 4076)	900 kW	Est. 2003-2004
22	VOC Extraction and Combustion	Remediation	NA	1993
23	Fort Wainwright Landfill	Landfill	1.97 million cubic meters	1962
24	Aerospace Activities	Painting and Degreasing	NA	1950s
26	Emergency Generator Building 2132	Cummins QSB7-G5 NR3	324 hp	2012
27	Emergency Generator Building 1580	John Deere 402HF285B	67 hp	2009
28	Emergency Generator Building 3406	Caterpillar C9 Genset	398 hp	2007
29	Emergency Generator Building 3567	SDMO TM30UCM	47 hp	2005
30	Fire Pump Building 2089	John Deere 6081AF001	275 hp	2007
31	Fire Pump #1 Building 1572	Clarke DDFP-04AT	235 hp	1994
32	Fire Pump #2 Building 1572	Clarke DDFP-04AT	235 hp	1994
33	Fire Pump #3 Building 1572	Clarke DDFP-04AT	235 hp	1994

EU ID	Emissions Unit Name	Emissions Unit Description	Rating/Size	Installation or Construction Date
34	Fire Pump #4 Building 1572	Clarke DDFP-04AT	235 hp	1994
35	Fire Pump #1 Building 2080	Cummins N-885-F	240 hp	1977
36	Fire Pump #2 Building 2080	Cummins N-885-F	240 hp	1977
37	Fire Pump Building 3498	Clarke, JU4H-UF40	105 hp	2005
38	Fire Pump #1 Building 5009	Clarke, PDFP-06YT	120 hp	1996
39	Fire Pump #2 Building 5009	Clarke, PDFP-06YT	120 hp	1996
40	Diesel-Fired Boiler Building 5007	Weil-McLain BL-988-SW	2.6 MMBtu/hr	1985
50	Emergency Generator Engine	Building 1060	762 hp	2010
51	Emergency Generator Engine	Building 1060	762 hp	2010
52	Emergency Generator Engine	Building 1193	82 hp	2002
53	Emergency Generator Engine	Building 1555	587 hp	2008
54	Emergency Generator Engine	Building 2117	1,059 hp	2005
55	Emergency Generator Engine	Building 2117	212 hp	2005
56	Emergency Generator Engine	Building 2088	176 hp	2007
57	Emergency Generator Engine	Building 2296	212 hp	2005
58	Emergency Generator Engine	Building 3004	71 hp	2007
59	Emergency Generator Engine	Building 3028	35 hp	1976
60a[1a]	Emergency Generator Engine	Building 3407	230 hp	2023
61	Emergency Generator Engine	Building 3703	50 hp	1993
62	Emergency Generator Engine	Building 5108	18 hp	2011

EU ID	Emissions Unit Name	Emissions Unit Description	Rating/Size	Installation or Construction Date
63	Emergency Generator Engine	Building 1620	68 hp	2003
64	Emergency Generator Engine	Building 1054	274 hp	2010
65	Emergency Generator Engine	Building 4390	274 hp	2010
66	Emergency Generator Engine	Building 3007	235 hp	2014
67	Emergency Generator Engine	Building 2121	67 hp	2016
68[1b]	Emergency Generator Engine	Building 3025	324 hp	2017
69[1b]	Emergency Generator Engine	Building 3030	86 hp	2023
NA	Paved Roads	Fugitive PM	8,376,750 vehicle miles traveled per year	Various
NA	Unpaved Roads	Fugitive PM	23,506 vehicle miles traveled per year	Various

Notes:

1. The following changes from AQ0236MSS03 Revision 1 are as follows:
   a. EU ID 60 was removed from the source in 2023 and replaced by EU ID 60a.
   b. EU IDs 68 and 69 are new emergency engines.

1. The Permittee shall comply with all applicable provisions of AS 46.14 and 18 AAC 50 when installing a replacement EU, including any applicable minor or construction permit requirements.

2. **Verification of Equipment Specifications and Maintenance of Equipment.** The Permittee shall install and maintain the equipment listed in Table 1 according to the manufacturer's or operator's maintenance procedures. Keep a copy of the manufacturer's or operator's maintenance procedure onsite and make records available to the Department personnel upon request. The records may be kept in electronic format.

Section 3 State Implementation Plan (SIP) Requirements

Fairbanks $PM_{2.5}$ Serious Non-attainment Area SIP Requirements

6. Diesel-Fired Boilers Emissions Limit. The Permittee shall limit the emissions from the diesel-fired boilers (EU IDs 8 through 10 and 40), as specified in Table 2.

Table 2 - EU IDs 8 through 10 and 40, SIP BACT Limits

Pollutant	BACT Control	Fuel Type	BACT Emissions Limit
$PM_{2.5}$	Good Combustion Practices and Limited Operation	Diesel	0.016 lb/MMBtu (three-hour average)

6.1. For EU IDs 8 through 10 and 40, the Permittee shall demonstrate compliance with the $PM_{2.5}$ best available control technology (BACT) emissions limit contained in Table 2 as follows:

a. Maintain good combustion practices at all times the EUs are in operation.

(i) Perform regular maintenance according to the manufacturer's and the operator's maintenance requirements and procedures.

(ii) Keep records of any maintenance that would have a significant effect on emissions. The records may be kept on electronic format.

(iii) Keep a copy of the manufacturer's and the operator's maintenance procedures.

b. Report in accordance with Condition 14, a summary of the maintenance records collected under Condition 6.1.a(ii).

c. Report the compliance status with the $PM_{2.5}$ emissions limit in Table 2 in accordance with each annual compliance certification described in Condition 15.

d. Report in accordance with Condition 13, whenever

(i) an emissions rate in Table 2 is exceeded, or

(ii) if any of the requirements in Conditions 6.1.a through 6.1.b are not met.

6.2. Limit the combined operation of EU IDs 8 through 10 to less than 600 hours per 12-month rolling period.

a. Monitor and record the time, date, and duration for which each of EU IDs 8 through 10 operate, calculate and record the cumulative total hours of operation per 12-consecutive month period.

b. Report in accordance with Condition 14, the operating hour records collected under Condition 6.2.a.

c. Report in accordance with Condition 13, whenever

(i) the combined operation of EU IDs 8 through 10 exceeds the limit in Condition 6.2; or

(ii) any of Condition 6.2.a through 6.2.b are not met.

7. **Diesel-Fired Engines Emissions Limit (I).** The Permittee shall limit the emissions from the diesel-fired engines (EU IDs 50, 51, and 53), as specified in Table 3.

Table 3 - EU IDs 50, 51, and 53, SIP BACT Limits

Pollutant	BACT Control	Fuel Type	BACT Emissions Limit
$PM_{2.5}$	Good Combustion Practices Limited Operation Combust only ULSD	ULSD	0.15 g/hp-hr

7.1. For EU IDs 50, 51, and 53, the Permittee shall demonstrate compliance with the $PM_{2.5}$ BACT emissions limit contained in Table 3 as follows:

a. Maintain good combustion practices at all times the EUs are in operation.

(i) Perform regular maintenance according to the manufacturer's and the operator's maintenance procedures.

(ii) Keep records of any maintenance that would have a significant effect on emissions. The records may be kept in electronic format.

(iii) Keep a copy of either the manufacturer's and the operator's maintenance procedures.

b. Combust only ultra-low sulfur diesel (ULSD) fuel, limit of 15 parts per million by weight (ppmw). Monitor, record, and report as follows:

(i) For each shipment of fuel, keep receipts that specify fuel grade and amount.

c. Limit the maintenance checks, readiness testing, and non-emergency operation of each EU to 100 hours per calendar year.

(i) For EU IDs 50, 51, and 53, monitor, record, and report as follows:

(A) Maintain and operate a non-resettable hour meter on each engine, capable of recording the total hours of operation.

(B) By the end of each calendar month, record the total operating hours of each EU

(1) for the previous calendar month; and

(2) for the previous 12 consecutive months, as calculated using the records obtained under Condition 7.1.c(i)(B)(1).

d. Report in accordance with Condition 14:

(i) a summary of the maintenance records collected under Condition 7.1.a(ii);

(ii) copies of the records required by Condition 7.1.b(i); and

(iii) the operating records for each engine collected under Condition 7.1.c(i)(B)(2).

e. Report the compliance status with the $PM_{2.5}$ emissions limit in Table 3 in accordance with each annual compliance certification described in Condition 15.

f. Report in accordance with Condition 13, whenever

(i) an emissions rate exceeds the limit in Table 3; or

(ii) if any of the requirements in Conditions 7.1.a through 7.1.e are not met.

8. Diesel-Fired Engines Emissions Limit (II). The Permittee shall limit the emissions from the diesel-fired engines, EU IDs 11 through 13, as specified in Table 4.

Table 4 - EU IDs 11 through 13, SIP BACT Limits

Pollutant	BACT Control	Fuel Type	BACT Emissions Limit
$PM_{2.5}$	Good Combustion Practices Limited Operation Combust only ULSD	ULSD	0.32 g/hp-hr

8.1. For EU IDs 11 through 13, the Permittee shall demonstrate compliance with the $PM_{2.5}$ BACT emissions limit contained in Table 4 as follows:

a. Maintain good combustion practices at all times the EUs are in operation.

(i) Perform regular maintenance according to the manufacturer's and the operator's maintenance procedures.

(ii) Keep records of any maintenance that would have a significant effect on emissions. The records may be kept in electronic format.

(iii) Keep a copy of either the manufacturer's and the operator's maintenance procedures.

b. Combust only ULSD fuel, limit of 15 ppmw. Monitor, record, and report as follows:

(i) For each shipment of fuel, keep receipts that specify fuel grade and amount.

c. Limit the combined operation of EU IDs 11 through 13 to less than 600 hours per 12-month rolling period.

(i) Maintain and operate a non-resettable hour meter on each engine, capable of recording the total hours of operation.

(ii) By the end of each calendar month, record the total operating hours of each EU and the EUs combined

(A) for the previous calendar month; and

(B) for the previous 12 consecutive months, as calculated using the records obtained under Condition 8.1.c(ii)(A).

d. Report in accordance with Condition 14:

(i) a summary of the maintenance records collected under Condition 8.1.a(ii);

(ii) copies of the records required by Condition 8.1.b(i); and

(iii) the operating records for each engine collected under Condition 8.1.c(ii)(B).

e. Report the compliance status with the $PM_{2.5}$ emissions limit in Table 4 in accordance each annual compliance certification described in Condition 15.

f. Report in accordance with Condition 13, whenever

(i) an emissions rate in Table 4 is exceeded, or

(ii) if any of the requirements in Conditions 8.1.a through 8.1.e are not met.

9. Diesel-Fired Engines Emissions Limit (III). The Permittee shall limit the emissions from the diesel-fired engines, EU ID 54, as specified in Table 5.

Table 5 - EU ID 54, SIP BACT Limits

Pollutant	BACT Control	Fuel Type	BACT Emissions Limit
$PM_{2.5}$	Good Combustion Practices and Limited Operation	ULSD	0.32 g/hp-hr

9.1. For EU ID 54, the Permittee shall demonstrate compliance with the $PM_{2.5}$ BACT emissions limit contained in Table 5 as follows:

a. Maintain good combustion practices at all times the EUs are in operation.

(i) Perform regular maintenance according to the manufacturer's and the operator's maintenance procedures.

(ii) Keep records of any maintenance that would have a significant effect on emissions. The records may be kept in electronic format.

(iii) Keep a copy of either the manufacturer's and the operator's maintenance procedures.

b. Combust only ULSD fuel, limit of 15 ppmw. Monitor, record, and report as follows:

(i) For each shipment of fuel, keep receipts that specify fuel grade and amount.

c. Limit the maintenance checks, readiness testing, and non-emergency operation of the EU to 100 hours per calendar year.

(i) Monitor, record, and report as follows:

(A) Maintain and operate a non-resettable hour meter, capable of recording the total hours of operation.

(B) By the end of each calendar month, record the total operating hours of the EU

(1) for the previous calendar month; and

(2) for the previous 12 consecutive months, as calculated using the records obtained under Condition 9.1.c(i)(B)(1).

d. Report in accordance with Condition 14:

(i) a summary of the maintenance records collected under Condition 9.1.a(ii);

(ii) copies of the records required by Condition 9.1.b(i); and

(iii) the operating records collected under Condition 9.1.c(i)(B)(2).

e. Report the compliance status with the $PM_{2.5}$ emissions limit in Table 5 in accordance each annual compliance certification described in Condition 15.

f. Report in accordance with Condition 13, whenever

(i) an emissions rate in Table 5 is exceeded, or

(ii) if any of the requirements in Conditions 9.1.a through 9.1.e are not met.

10. Small Diesel-Fired Engines Emissions Limit. The Permittee shall limit the emissions from the small diesel-fired engines, EU IDs 26 through 39, 52, and 55 through 69, as specified in Table 6.

Table 6 - EU IDs 26 through 39, 52, and 55 through 69, SIP BACT Limits

<table>
<tr><th>Pollutant</th><th>BACT Control</th><th>Fuel Type</th><th>BACT Emissions Limit</th></tr>
<tr><td rowspan="6">PM_{2.5}</td><td rowspan="6">Good Combustion Practices
Combust only ULSD
Limited Operation</td><td rowspan="6">ULSD</td><td>EU IDs 29, 31 – 39, 52, 55, 57, 59, 61, and 63</td></tr>
<tr><td>0.0022 lb/hp-hr</td></tr>
<tr><td>EU IDs 26, 28, 30, 60a, 64, 65, 66, and 68</td></tr>
<tr><td>0.2 g/kW-hr</td></tr>
<tr><td>EU ID 27</td></tr>
<tr><td>0.3 g/kW-hr</td></tr>
</table>

			EU ID 56
			0.4 g/hp-hr
			EU IDs 58, 62, 67, and 69
			0.4 g/kW-hr

10.1. For EU IDs 26 through 39, 52, and 55 through 69, the Permittee shall demonstrate compliance with the $PM_{2.5}$ BACT emissions limit contained in Table 6 as follows:

a. Maintain good combustion practices at all times the EUs are in operation.

(i) Perform regular maintenance according to the manufacturer's and the operator's maintenance procedures.

(ii) Keep records of any maintenance that would have a significant effect on emissions. The records may be kept in electronic format.

(iii) Keep a copy of either the manufacturer's and the operator's maintenance procedures.

b. Combust only ULSD fuel, limit of 15 ppmw. Monitor, record, and report as follows:

(i) For each shipment of fuel, keep receipts that specify fuel grade and amount.

c. Limit the maintenance checks, readiness testing, and non-emergency operation of each EU to 100 hours per calendar year.

(i) For each of EU IDs 26 through 39, 52, and 55 through 69, monitor and record as follows:

(A) Maintain and operate a non-resettable hour meter, capable of recording the total hours of operation.

(B) By the end of each calendar month, record the total operating hours of each EU

(1) for the previous calendar month; and

(2) for the previous 12 consecutive months, as calculated using the records obtained under Condition 10.1.c(i)(B)(1).

d. Report in accordance with Condition 14:

(i) a summary of the maintenance records collected under Condition 10.1.a(ii);

(ii) copies of the records required by Condition 10.1.b(i); and

(iii) the operating records for each engine collected under Condition 10.1.c(i)(B)(2).

e. Report the compliance status with the $PM_{2.5}$ emissions limit in Table 6 in accordance each annual compliance certification described in Condition 15.

f. Report in accordance with Condition 13, whenever

(i) an emissions rate in Table 6 is exceeded, or

(ii) if any of the requirements in Conditions 10.1.a through 10.1.e are not met.

Section 4 Recordkeeping, Reporting, and Certification Requirements

11. Certification. The Permittee shall certify any permit application, report, affirmation, or compliance certification submitted to the Department and required under the permit by including the signature of a responsible official for the permitted stationary source following the statement: "*Based on information and belief formed after reasonable inquiry, I certify that the statements and information in and attached to this document are true, accurate, and complete.*" Excess emissions reports must be certified either upon submittal or with an operating report required for the same reporting period. All other reports and other documents must be certified upon submittal.

11.1. The Department may accept an electronic signature on an electronic application or other electronic record required by the Department if the person providing the electronic signature

a. uses a security procedure, as defined in AS 09.80.190, that the Department has approved; and

b. accepts or agrees to be bound by an electronic record executed or adopted with that signature.

12. Submittals. Unless otherwise directed by the Department or this permit, the Permittee shall submit to the Department one certified copy of reports, compliance certifications, and/or other submittals required by this permit. The Permittee may submit the documents electronically or by hard copy.

12.1. Submit the certified copy of reports, compliance certifications, and/or other submittals in accordance with the submission instructions on the Department's Standard Permit Conditions web page at http://dec.alaska.gov/air/air-permit/standard-conditions/standard-condition-xvii-submission-instructions/.

13. Excess Emissions and Permit Deviation Reports. The Permittee shall report excess emissions and permit deviations as follows:

13.1. **Excess Emissions Reporting.** The Permittee shall report all emissions or operations that exceed emissions standards or limits of this permit as follows:

a. In accordance with 18 AAC 50.240(c), as soon as possible after the event commenced or is discovered, report

(i) excess emissions that present a potential threat to human health or safety; and

(ii) excess emissions that the Permittee believes to be unavoidable.

b. In accordance with 18 AAC 50.235(a), within two working days after the event commenced or was discovered, report an unavoidable emergency, malfunction, or nonroutine repair that causes emissions in excess of a technology-based emissions standard.

c. If a continuous or recurring excess emissions is not corrected within 48 hours of discovery, report within 72 hours of discovery unless the Department provides written permission to report under Condition 13.1.d.

d. Report all other excess emissions not described in Conditions 13.1.a, 13.1.b, and 13.1.c within 30 days after the end of the month during which the excess emissions occurred or as part of the next routine operating report in Condition 14 for excess emissions that occurred during the period covered by the report, whichever is sooner.

e. If requested by the Department, the Permittee shall provide a more detailed written report to follow up on an excess emissions report.

13.2. **Permit Deviations Reporting.** For permit deviations that are not "excess emissions," as defined under 18 AAC 50.990:

a. Report all other permit deviations within 30 days after the end of the month during which the deviation occurred or as part of the next routine operating report in Condition 14 for permit deviations that occurred during the period covered by the report, whichever is sooner.

13.3. **Reporting Instructions.** When reporting either excess emissions or permit deviations, the Permittee shall report using the Department's online form for all such submittals, beginning no later than September 7, 2023. The form can be found at the Division of Air Quality's Air Online Services (AOS) system webpage http://dec.alaska.gov/applications/air/airtoolsweb using the Permittee Portal option. Alternatively, upon written Department approval, the Permittee may submit the form contained in Section 8 of this permit. The Permittee must provide all information called for by the form that is used. Submit the report in accordance with the submission instructions on the Department's Standard Permit Conditions webpage found at http://dec.alaska.gov/air/air-permit/standard-conditions/standard-conditions-iii-and-iv-submission-instructions/.

14. Operating Reports. During the life of this permit[1], the Permittee shall submit to the Department an operating report in accordance with Conditions 11 and 12 by August 1 for the period January 1 to June 30 of the current year and by February 1 for the period July 1 to December 31 of the previous year.

14.1. The operating report must include all information required to be in operating reports by other conditions of this permit, for the period covered by the report.

14.2. When excess emissions or permit deviations that occurred during the reporting period are not included with the operating report under Condition 14.1, the Permittee shall identify

a. the date of the excess emissions or permit deviation;

[1] *Life of this permit* is defined as the permit effective dates, including any periods of reporting obligations that extend beyond the permit effective dates. For example, if a permit expires prior to the end of a calendar year, there is still a reporting obligation to provide operating reports for the periods when the permit was in effect.

b. the equipment involved;

c. the permit condition affected;

d. a description of the excess emissions or permit deviation; and

e. any corrective action or preventive measures taken and the date(s) of such actions; or

14.3. when excess emissions or permit deviation reports have already been reported under Condition 13 during the period covered by the operating report, the Permittee shall either

a. include a copy of those excess emissions or permit deviation reports with the operating report; or

b. cite the date(s) of those reports.

15. Annual Compliance Certification. Each year by March 31, the Permittee shall compile and submit to the Department an annual compliance certification report according to Condition 12.

15.1. Certify the compliance status of the stationary source over the preceding calendar year consistent with the monitoring required by this permit, as follows:

a. identify each term or condition set forth in Section 2through Section 6, that is the basis of the certification;

b. briefly describe each method used to determine the compliance status;

c. state whether compliance is intermittent or continuous; and

d. identify each deviation and take it into account in the compliance certification.

15.2. In addition, submit a copy of the report directly to the Clean Air Act Compliance Manager, US EPA Region 10, ATTN: Air Toxics and Enforcement Section, Mail Stop: 20-C04, 1200 Sixth Avenue, Suite 155, Seattle, WA 98101-3188.

Section 6 General Source Test Requirements

22. Requested Source Tests. In addition to any source testing explicitly required by this permit, the Permittee shall conduct source testing as requested by the Department to determine compliance with applicable permit requirements.

23. Operating Conditions. Unless otherwise specified by an applicable requirement or test method, the Permittee shall conduct source testing

23.1. at a point or points that characterize the actual discharge into the ambient air; and

23.2. at the maximum rated burning or operating capacity of the emissions unit or another rate determined by the Department to characterize the actual discharge into the ambient air.

24. Reference Test Methods. The Permittee shall use the following references for test methods when conducting source testing for compliance with this permit:

24.1. Source testing for the reduction in visibility through the exhaust effluent must be conducted in accordance with the procedures set out in 40 C.F.R. 60, Appendix A, Reference Method 9. The Permittee may use the form in Attachment 1 of this permit to record data.

24.2. Source testing for emissions of total particulate matter, sulfur compounds, nitrogen compounds, carbon monoxide, lead, volatile organic compounds, fluorides, sulfuric acid mist, municipal waste combustor organics, metals and acid gases must be conducted in accordance with the methods and procedures specified in 40 C.F.R. 60, Appendix A.

24.3. Source testing for emissions of PM_{10} and $PM_{2.5}$ must be conducted in accordance with the procedures specified in 40 C.F.R. 51, Appendix M, Methods 201 or 201A and 202.

24.4. Source testing for emissions of any contaminant may be determined using an alternative method approved by the Department in accordance with 40 C.F.R. 63 Appendix A, Method 301.

25. Excess Air Requirements. To determine compliance with this permit, standard exhaust gas volumes must include only the volume of gases formed from the theoretical combustion of the fuel, plus the excess air volume normal for the specific emissions unit type, corrected to standard conditions (dry gas at 68° F and an absolute pressure of 760 millimeters of mercury).

26. Test Deadline Extension. The Permittee may request an extension to a source test deadline established by the Department. The Permittee may delay a source test beyond the original deadline only if the extension is approved in writing by the Department's appropriate division director or designee.

27. Test Plans. Before conducting any source tests, the Permittee shall submit a plan to the Department. The plan must include the methods and procedures to be used for sampling, testing, and quality assurance and must specify how the emissions unit will operate during the test and how the Permittee will document that operation. The Permittee shall submit a complete plan within 60 days after receiving a request under Condition 22 and at least 30 days before the scheduled date of any test unless the Department agrees in writing to some other time period. Retesting may be done without resubmitting the plan.

28. Test Notification. At least 10 days before conducting a source test, the Permittee shall give the Department written notice of the date and time the source test will begin.

29. Test Reports. Within 60 days after completing a source test, the Permittee shall submit one certified copy of the results in the format set out in the *Source Test Report Outline*, adopted by reference in 18 AAC 50.030. The Permittee shall certify the results in the manner set out in Condition 11. If requested in writing by the Department, the Permittee must provide preliminary results in a shorter period of time specified by the Department.

GVEA North Pole Power Plant BACT Cover Page

Contents

1. 10.21.24 Final North Pole Power Plant BACT Determination
2. 10.21.24 North Pole Power Plant SO_2 BACT MR&R Final
3. AQ0110MSS01 Rev. 1 Final Permit

The following spreadsheets are included as part of the appendix. However, due to their electronic nature, they may be found posted separately on the web page:

1. Updated Department North Pole Plant SO_2 Controls Economic Analysis.xlsx
2. GVEA Fuel Prices.xlsx
3. AQ0110TVP04 NPP FuelPrices Provided 02.24.2021.xlsx

ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION
Air Permits Program

BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION ADDENDUM for Golden Valley Electric Association North Pole Power Plant

Prepared by: Dave Jones
Reviewed by: Moses Coss
Final Date: October 21, 2024

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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

The North Pole Power Plant (North Pole) is an electric generating facility that combusts distillate fuel in combustion turbines to provide power to the Golden Valley Electric Association (GVEA) grid. The power plant contains two fuel oil-fired simple cycle gas combustion turbines, two fuel oil-fired combined cycle gas combustion turbines, one fuel oil-fired emergency generator, and two propane fired boilers.

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

The initial BACT Determination for North Pole was included in Part 4 of Appendix III.D.7.07 Control Strategies Chapter, in the State Air Quality Control Plan adopted on November 19, 2019, with amendments adopted on November 18, 2020, as part of a complete SIP package.[2] The *EPA's Air Plan Partial Approval and Partial Disapproval; AK, Fairbanks North Star Borough; 2006 24-hour $PM_{2.5}$ Serious Area and 189(d) Plan*[3] published in the Federal Register on December 5, 2023 (*88 Fed. Reg. 84659*) disapproved of Alaska's initial BACT determinations for $PM_{2.5}$ and SO_2 controls.

This BACT addendum addresses the EPA's disapproval of the significant emission units (EUs) listed in the North Pole Power Plant's operating permit AQ0110TVP04 Rev. 1. The BACT addendum also accounts for EPA's comments listed in Memorandum dated August 24, 2022 from Zach Hedgpeth, LSASD to Matthew Jentgen, ARD.[4] This BACT addendum provides the Department's review of the BACT analysis for $PM_{2.5}$, and the BACT analysis for sulfur dioxide (SO_2) emissions, which is a precursor pollutant that can form $PM_{2.5}$ in the atmosphere post combustion.

Since preparing the SIP amendments adopted on November 18, 2020, the Department conducted extensive modeling and found that SO_2 emissions from stationary sources do not significantly contribute to ground level $PM_{2.5}$ concentrations, and that SO_2 BACT emission limits are therefore not required for major stationary sources in the Fairbanks North Star Borough. SO_2

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

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

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

[4] Document 000007_EPA Technical Support Document – GVEA BACT TSD v20220824: https://www.regulations.gov/document/EPA-R10-OAR-2022-0115-0214.

BACT determinations have, however, been included in this BACT Determination Addendum because the SO_2 major source precursor demonstration has not yet been approved by EPA.

Note that the section for oxides of nitrogen (NOx), which is also a precursor pollutant that can form $PM_{2.5}$ in the atmosphere post combustion, has been removed from this addendum because the EPA has approved[3] of the Department's comprehensive NOx precursor demonstration under 40 C.F.R. 51.1006(a)(1) and 51.1010(a)(2)(ii).

The following sections review GVEA's BACT analysis provided for the North Pole Power Plant for technical accuracy and adherence to accepted engineering cost estimation practices.

2. BACT EVALUATION

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

Table A: Emission Units Subject to BACT Review

EU	EU Name	Description of EU	Rating/Size	Installation Date
1	GT#1	GE Frame 7, Series 7001, Fuel Oil-Fired Model BR Regenerative Simple Cycle Gas Turbine	672 MMBtu/hr (60.5 MW)	1976
2	GT#2	GE Frame 7, Series 7001, Fuel Oil-Fired Model BR Regenerative Simple Cycle Gas Turbine	672 MMBtu/hr (60.5 MW)	1977
5	GT#3	GE LM6000PC Combined Cycle Gas Turbine, Fuel 0-GT (naphtha/LSR fuel) Fired (with water injection for NOx control and CO oxidation catalyst)	455 MMBtu/hr (Higher Heating Value) 43 MW (nominal)	2005
6	GT#4	GE LM6000PC Combined Cycle Gas Turbine, Fuel 0-GT (naphtha/LSR fuel) Fired (with water injection for NOx control and CO oxidation catalyst)	455 MMBtu/hr (Higher Heating Value) 43 MW (nominal)	TBD
7	Emergency Generator	IC Engine, Fuel-Oil Fired	400 kW	2005
11	Propane-Fired Boiler	Bryan Steam RV500 Heater, Gas Fuel-Fired	5.0 MMBtu/hr	2005
12	Propane-Fired Boiler	Bryan Steam RV500 Heater, Gas Fuel-Fired	5.0 MMBtu/hr	2005

GVEA did not include BACT analyses for EUs 3 and 4. These emission units are fuel storage tanks and do not have NOx, $PM_{2.5}$, or SO_2 emissions.

Five-Step BACT Determinations

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

Step 1 Identify All Potentially Available Control Technologies

The Department identifies all available control technologies for the EUs and the pollutant under consideration. This includes technologies used throughout the world or emission reductions through the application of available control techniques, changes in process design, and/or operational limitations. To assist in identifying available controls, the Department reviews available 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. It is usually the first stop for BACT research. In addition to the RBLC search, the Department used several search engines to look for emerging and tried technologies used to control $PM_{2.5}$ and SO_2 emissions from equipment similar to those listed in Table A.

Step 2 Eliminate Technically Infeasible Control Technologies

The Department evaluates the technical feasibility of each control option based on source specific factors in relation to each EU subject to BACT. Based on sound documentation and demonstration, the Department eliminates control technologies deemed technically infeasible due to physical, chemical, and engineering difficulties.

Step 3 Rank the Remaining Control Technologies by Control Effectiveness

The Department ranks the remaining control technologies in order of control effectiveness with the most effective at the top.

Step 4 Evaluate the Most Effective Controls and Document the Results as Necessary

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

Step 5 Select BACT

The Department selects the most effective control option not eliminated in Step 4 as BACT for the pollutant and EU under review. The Department 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 GVEA's BACT analysis and made BACT determinations for $PM_{2.5}$ and SO_2 for the North Pole Power Plant. These BACT determinations are based on the information submitted by GVEA in their analysis, information from vendors, suppliers, sub-contractors, RBLC, and an exhaustive internet search.

3. BACT DETERMINATION FOR NO_X

As discussed in the Section 1 Introduction, this BACT addendum has removed the previous NOx BACT determinations included in the State Air Quality Control Plan adopted on November 19, 2019, with amendments adopted on November 18, 2020,[2] because the optional comprehensive precursor demonstration (as allowed under 40 C.F.R. 51.1006(1) and 51.1010(a)(2)(ii)) for the precursor gas NOx for point sources illustrates that NOx controls are not needed. The Department submitted with the Serious SIP a final comprehensive precursor demonstration as justification not to require post emission controls for NOx. Please see the precursor demonstration for NOx in the Serious SIP Modeling Chapter III.D.7.8.[2] The $PM_{2.5}$ NAAQS Final SIP Requirements Rule states if the state determines through a precursor demonstration that controls for a precursor gas are not needed for attaining the standard, then the controls identified as BACT/BACM or Most Stringent Measure for the precursor gas are not required to be implemented.[5] The Department's NOx precursor demonstration was approved in *EPA's Air Plan Partial Approval and Partial Disapproval; AK, Fairbanks North Star Borough; 2006 24-hour $PM_{2.5}$ Serious Area and 189(d) Plan*[3] published in the Federal Register on December 5, 2023 (*88 Fed. Reg. 84659*).

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 Fuel Oil-Fired Simple Cycle Gas Turbines (EUs 1 and 2)

Possible $PM_{2.5}$ emission control technologies for the fuel oil-fired simple cycle gas turbines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 15.110 Simple Cycle Gas Turbines (rated at 25 MW or more) The search results for simple cycle gas turbines are summarized in Table 4-1.

Table 4-1. RBLC Summary of $PM_{2.5}$ Control for Simple Cycle Gas Turbines

Control Technology	Number of Determinations	Emission Limits
Good Combustion Practices	25	0.0038 – 0.0076 lb/MMBtu
Clean Fuels	12	5 – 14 lb/hr

RBLC Review

A review of similar units in the RBLC indicates restrictions on fuel sulfur contents and good

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

combustion practices are the principal PM control technologies installed on simple cycle gas turbines. The lowest $PM_{2.5}$ emission rate listed in the RBLC is 0.0038 lb/MMBtu.

Step 1 - Identification of $PM_{2.5}$ Control Technology for the Simple Cycle Gas Turbines
From research, the Department identified the following technologies as available for control of $PM_{2.5}$ emissions from fuel oil-fired simple cycle gas turbines:

(a) Low Sulfur Fuel
Low sulfur fuel has been known to reduce particulate matter emissions. $PM_{2.5}$ emission rates for low sulfur fuel are not available and therefore a BACT emissions rate cannot be set for low sulfur fuel. The Department does not consider low sulfur fuel a technically feasible control technology for the fuel oil-fired simple cycle gas turbines.

(b) Low Ash Fuel
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 combustion components. EUs 1 and 2 are fired exclusively on distillate fuel which is a form of refined fuel, and potential $PM_{2.5}$ emissions are based on emission factors for distillate fuel. The Department considers low ash fuel a technically feasible control technology for the fuel oil-fired simple cycle gas turbines.

(c) Limited Operation
Limiting the operation of emission units reduces the potential to emit for those units. Due to EUs 1 and 2 currently operating under limits, the Department considers limited operation as a technically feasible control technology for the fuel oil-fired simple cycle gas turbines.

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

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

Combustion efficiency is dependent on the gas residence time, the combustion temperature, and the amount of mixing in the combustion zone. GCPs are accomplished primarily through combustion chamber design as it relates to residence time, combustion temperature, air-to-fuel mixing, and excess oxygen levels. 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 fuel oil-fired simple cycle gas turbines.

Step 2 - Eliminate Technically Infeasible $PM_{2.5}$ Technologies for the Simple Cycle Gas Turbines
As explained in Step 1 of Section 4.1, the Department does not consider low sulfur fuel as a technically feasible technology to control $PM_{2.5}$ emissions from the fuel oil-fired simple cycle gas turbines.

Step 3 - Rank the Remaining $PM_{2.5}$ Control Technologies for the Simple Cycle Gas Turbines
The following control technologies have been identified and ranked by efficiency for the control of $PM_{2.5}$ emissions from the fuel oil-fired simple cycle gas turbines:

(d)	Good Combustion Practices	(Less than 40% Control)
(b)	Low Ash Fuel	(0% Control)
(c)	Limited Operation	(0% Control)

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

Step 4 - Evaluate the Most Effective Controls

GVEA BACT Proposal

GVEA proposes the following as BACT for $PM_{2.5}$ emissions from the fuel oil-fired simple cycle gas turbines:

(a) $PM_{2.5}$ emissions from EUs 1 and 2 shall not exceed 0.012 lb/MMBtu over a 4-hour averaging period; and

(b) Maintain good combustion practices.

Step 5 - Selection of $PM_{2.5}$ BACT for the Simple Cycle Gas Turbines
The Department's finding is that BACT for $PM_{2.5}$ emissions from the fuel oil-fired simple cycle gas turbine is as follows:

(a) $PM_{2.5}$ emissions from EU 1 shall be limited by complying with the combined annual NOx emissions limit for EUs 1, 5, and 6, listed in Conditions 16.1a of Construction Permit AQ0110CPT01 Rev. 1;

(b) $PM_{2.5}$ emissions from EU 2 shall be limited by complying with the 7,992 operating hour limit to reduce NOx emissions listed in Condition 16.1 of Construction Permit AQ0110CPT01 Rev. 1;

(c) $PM_{2.5}$ emissions from EUs 1 and 2 shall be controlled by combusting only low ash fuel;

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

(e) $PM_{2.5}$ emissions from EUs 1 & 2 shall not exceed 0.012 lb/MMBtu[6] over a 3-hour averaging period.

Table 4-2 lists the proposed $PM_{2.5}$ BACT determination for this facility along with those for other fuel oil-fired simple cycle gas turbines located in the Serious $PM_{2.5}$ nonattainment area.

[6] Table 3.1-2a of US EPA's AP-42 Emission Factors. https://www3.epa.gov/ttnchie1/ap42/ch03/final/c03s01.pdf

Table 4-2. Comparison of $PM_{2.5}$ BACT for Simple Cycle Gas Turbines at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
GVEA – North Pole	Two Fuel Oil-Fired Simple Cycle Gas Turbines	1,344 MMBtu/hr	0.012 lb/MMBtu[6] (3-hour averaging period)	Limited Operation Low Ash Fuel Good Combustion Practices
GVEA – Zehnder	Two Fuel Oil-Fired Simple Cycle Gas Turbines	536 MMBtu/hr	0.012 lb/MMBtu[6] (3-hour averaging period)	Low Ash Fuel Good Combustion Practices

4.2 $PM_{2.5}$ BACT for the Combined Cycle Gas Turbines (EUs 5 and 6)

Possible $PM_{2.5}$ emission control technologies for the fuel oil-fired combined cycle gas turbines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 15.210, Liquid Fuel-Fired Combined Cycle Combustion Turbines (rated at 25 MW or more). The search results for combined cycle gas turbines are summarized in Table 4-3.

Table 4-3. RBLC Summary for $PM_{2.5}$ Control for the Combined Cycle Gas Turbines

Control Technology	Number of Determinations	Emission Limits
Good Combustion Practices	9	4 – 19.35 lb/hr
Clean Fuels	12	4.7 – 60.6 lb/hr

RBLC Review
A review of similar units in the RBLC indicates good combustion practices and clean fuels are the principal $PM_{2.5}$ control technologies installed on fuel oil-fired combined cycle gas turbines. The lowest NOx emission rate listed in the RBLC is 4 lb/hr.

Step 1 - Identification of $PM_{2.5}$ Control Technology for the Combined Cycle Gas Turbines
From research, the Department identified the following technologies as available for control of $PM_{2.5}$ emissions from fuel oil-fired combined cycle gas turbines rated at 25 MW or more:

(a) Low Sulfur Fuel
Low sulfur fuel has been known to reduce particulate matter emissions. The Department considers low sulfur fuel a technically feasible control technology for the fuel oil-fired combined cycle gas turbines.

(b) Limited Operation
Limiting the operation of emission units reduces the potential to emit for those units. EUs 5 and 6 currently operate under a combined ORL with EU 1 to restrict the combined NOx emissions from these three units to no more than 1,600 tons per 12 month rolling period. The Department considers limited operation a technically feasible control technology for the fuel oil-fired combined cycle gas turbines.

(c) Good Combustion Practices
The theory of GCPs was discussed in detail in the $PM_{2.5}$ BACT section for the fuel oil-fired simple cycle turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of particulate matter. The Department considers GCPs a technically feasible control technology for the fuel oil-fired combined cycle turbines.

Step 2 - Eliminate Technically Infeasible $PM_{2.5}$ Controls for the Combined Cycle Gas Turbines
As explained in Step 1 of Section 4.1, the Department does not consider low sulfur fuel as technically feasible technology to control $PM_{2.5}$ emissions from the fuel oil-fired combined cycle gas turbines.

Step 3 - Rank the Remaining $PM_{2.5}$ Controls for the Combined Cycle Gas Turbines
The following control technologies have been identified and ranked by efficiency for the control of $PM_{2.5}$ emissions from the combined cycle gas turbines:

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

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

Step 4 - Evaluate the Most Effective Controls

GVEA BACT Proposal

GVEA proposes the following as BACT for $PM_{2.5}$ emissions from the fuel oil-fired combined cycle gas turbines:

(a) $PM_{2.5}$ emissions shall not exceed 0.012 lb/MMBtu over a 4-hour averaging period; and

(b) Maintain good combustion practices.

Department Evaluation of BACT for $PM_{2.5}$ Emissions from the Combined Cycle Gas Turbines

The Department reviewed GVEA's proposal and found that in addition to maintaining good combustion practices, limited operation is also a technically feasible control technology.

Step 5 - Selection of $PM_{2.5}$ BACT for the Combined Cycle Gas Turbines
The Department's finding is that BACT for $PM_{2.5}$ emissions from the combined cycle gas turbines is as follows:

(a) $PM_{2.5}$ emissions from EUs 5 and 6 shall be limited by complying with the combined annual NOx emissions limit listed in Condition 16.1a of Construction Permit AQ0110CPT01 Rev. 1 of Construction Permit AQ0110CPT01 Rev. 1**;**

(b) $PM_{2.5}$ emissions from EUs 5 and 6 shall not exceed 0.012 lb/MMBtu[6] over a 3-hour averaging period; and

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

4.3 $PM_{2.5}$ BACT for the Large Diesel-Fired Engine (EU 7)

Possible $PM_{2.5}$ emission control technologies for the large diesel-fired engine were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 17.110-17.190, Large Internal Combustion Engines (>500 hp). The search results for large diesel-fired engines are summarized in Table 4-5.

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 principal $PM_{2.5}$ control technologies installed on large diesel-fired engines. The lowest $PM_{2.5}$ emission rate in the RBLC is 0.02 g/hp-hr.

Step 1 - Identification of $PM_{2.5}$ Control Technology for the Large Diesel-Fired Engine
From research, the Department identified the following technologies as available for controls 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 is 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. DPF can reduce $PM_{2.5}$ emissions by 85%. The Department considers DPF a technically feasible control technology for the large diesel-fired engine.

(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 resulting in decreased concentrations. They replace mufflers on vehicles, and require no modifications. More specifically, this is a honeycomb type structure that has a large area coated with an active catalyst layer. As CO and other gaseous hydrocarbon particles travel along the catalyst, they are oxidized thus reducing pollution. The Department considers DOC a technically feasible control technology for the large diesel-fired engine.

(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. Positive crankcase ventilation is included in the design of EU 7. The Department considers positive crankcase ventilation a technically feasible control technology for the large diesel-fired engine.

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

(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. EU 7 is fired exclusively on distillate fuel which is a form of refined fuel. The potential $PM_{2.5}$ emissions are based on emission factors for distillate fuel. The Department considers low ash diesel a technically feasible control technology for the large diesel-fired engine.

(f) Federal Emission Standards
NSPS Subpart IIII applies to stationary compression ignition internal combustion engines that are manufactured or reconstructed after July 11, 2005. Due to EU 7 not being subject to either 40 C.F.R. 60 Subpart IIII or 40 C.F.R. 63 Subpart ZZZZ emission standards, the Department does not consider federal emission standards a technically feasible control technology for the large diesel-fired engine.

(g) Limited Operation
Limiting the operation of emissions units reduces the potential to emit of those units. Due to EU 7 currently operating under an annual hour limit of no more than 52 hours per 12 month rolling period, the Department considers limited operation a technically feasible control technology for the large diesel-fired engine.

(h) Good Combustion Practices
The theory of GCPs was discussed in detail in the $PM_{2.5}$ BACT section for the fuel oil-fired simple cycle turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of NOx emissions. The Department considers GCPs a technically feasible control technology for the large diesel-fired engine.

Step 2 - Eliminate Technically Infeasible $PM_{2.5}$ Control Technologies for the Large Engine
$PM_{2.5}$ emission rates for low sulfur fuel are not available and therefore a BACT emissions rate cannot be set for low sulfur fuel. Low sulfur fuel is not a technically feasible control technology. As explained in Step 1 of Section 4.3, federal emission standards are not technically feasible control technology for control of $PM_{2.5}$ emissions from the large diesel-fired engine.

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

(a)	Diesel Particulate Filters	(85% Control)
(g)	Good Combustion Practices	(Less than 40% Control)
(b)	Positive Crankcase Ventilation	(0% Control)
(d)	Low Ash Diesel	(0% Control)
(f)	Limited Operation	(0% Control)

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

Step 4 - Evaluate the Most Effective Controls

GVEA Proposal

GVEA provided an economic analysis for the installation of diesel particulate filter. A summary of the analysis for is shown below:

Table 4-6. GVEA Economic Analysis for Technically Feasible $PM_{2.5}$ Controls

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annual Costs ($/year)	Cost Effectiveness ($/ton)
Diesel Particulate Filter	0.035	0.03	$30,229	$4,304	$143,008
Capital Recovery Factor = 0.1424 (7% interest rate for a 10 year equipment life)					

GVEA contends that the economic analysis indicates that the level of $PM_{2.5}$ reduction does not justify the use of a diesel particulate filter based on the excessive cost per ton of $PM_{2.5}$ removed per year.

GVEA proposes the following as BACT for $PM_{2.5}$ emissions from the large diesel-fired engine:

(a) $PM_{2.5}$ emissions from EU 7 shall be controlled by operating with positive crankcase ventilation;

(b) Maintaining good combustion practices;

(c) $PM_{2.5}$ emissions from EU 7 shall be controlled by limiting operation to no more than 52 hours per 12 month rolling period; and

(d) $PM_{2.5}$ emissions from EU 7 shall not exceed 0.0022 lb/hp-hr[7] over a 4-hour averaging period.

Department Evaluation of BACT for $PM_{2.5}$ Emissions from the Large Diesel-Fired Engine
The Department reviewed GVEA's proposal for the large diesel-fired engine and finds that installing a diesel particulate filter is an economically infeasible control technology. The Department does not agree with some of the assumptions provided in GVEA's cost analysis that

[7] Emissions Inventory Data: http://dec.alaska.gov/Applications/Air/airtoolsweb/PointSourceEmissionInventory/XmlInventory?reportingYear=2017&organizationKey=10&facilityKey=110&addEmissionUnits=0&addReleasePoints=0

cause an overestimation of the cost effectiveness. However, since EU 7 is limited to 52 hours per year, the Department finds it unnecessary to revise the cost analysis as a decrease in 0.03 tpy of $PM_{2.5}$ from EU 7 will not be cost effective for installing a diesel particulate filter.

Step 5 - Selection of $PM_{2.5}$ BACT for the Large Diesel-fired Engine

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

(a) $PM_{2.5}$ emissions from EU 7 shall be controlled by operating with positive crankcase ventilation;

(b) $PM_{2.5}$ emissions from EU 7 shall be controlled by limiting operation to no more than 52 hours per 12 month rolling period;

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

(d) $PM_{2.5}$ emissions from EU 7 shall not exceed 0.32 g/hp-hr[8] over a 3-hour averaging period.

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

Facility	Process Description	Capacity	Limitation	Control Method
UAF	Large Diesel-Fired Engine	**> 500 hp**	0.05 – 0.32 g/hp-hr (3-hour averaging period)	Positive Crankcase Ventilation Limited Operation Ultra-Low Sulfur Diesel
Fort Wainwright	8 Large Diesel-Fired Engines	> 500 hp	0.15 – 10.9 g/hp-hr (3-hour averaging period)	Limited Operation Ultra-Low Sulfur Diesel Federal Emission Standards Good Combustion Practices
GVEA North Pole	Large Diesel-Fired Engine	600 hp	0.32 g/hp-hr (3-hour averaging period)	Positive Crankcase Ventilation Limited Operation Good Combustion Practices
GVEA Zehnder	2 Large Diesel-Fired Engines	11,000 hp (each)	0.32 g/hp-hr (3-hour averaging period)	Limited Operation Good Combustion Practices

4.5 $PM_{2.5}$ BACT for the Propane-Fired Boilers (EUs 11 and 12)

Possible $PM_{2.5}$ emission control technologies for the propane-fired boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 13.310, Gas-Fired Boilers (<100 MMBtu/hr). The search results for gas-fired boilers are summarized in Table 4-8.

Table 4-8. RBLC Summary of $PM_{2.5}$ Control for Gas-Fired Boilers

[8] Table 3.4-1 of US EPA's AP-42 Emission Factors (PM). https://www3.epa.gov/ttn/chief/ap42/ch03/final/c03s04.pdf.

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Good Combustion Practices	49	0.0019 – 0.0095
Electrostatic Precipitator	3	0.015 – 0.032

RBLC Review
A review of similar units in the RBLC indicates that good combustion practices and electrostatic precipitators are the principal $PM_{2.5}$ control technology determined for propane-fired boilers. The lowest $PM_{2.5}$ emission rate listed in the RBLC is 0.0019 lb/MMBtu.

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

(a) Low Sulfur Fuel
The boilers (EUs 11 and 12) are fired using propane, which is an inherently low sulfur fuel. Condition 11 of AQ0110TVP03 limits the sulfur content of the propane combusted in the boilers to 120 ppmv. Recent tests indicate that the propane fired in the boilers contains less than 3 ppm H_2S as determined by the length-of-stain methodology. The Department considers low sulfur fuel a technically feasible control technology for the propane-fired boilers.

(b) Flue Gas Recirculation
Flue gas recirculation (FGR) involves recycling a portion of the combustion gases from the stack to the boiler combustion air intake. The combustion products are low in oxygen, and when mixed with the combustion air, lower the overall excess oxygen concentration. This process acts as a heat sink to lower the peak flame temperature as well as the residence time at peak flame temperature. These effects work together to limit thermal NOx formation. FGR also increases the amount of combustion, which lowers PM emissions. The Department considers FGR to be a technically feasible control technology for the propane-fired boilers.

(c) Baghouse
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. Baghouses are characterized by the type of cleaning cycle - mechanical-shaker, pulse-jet, and reverse-air. Fabric filter systems have control efficiencies of 95% to 99.9% [9] and are generally specified to meet a discharge concentration of filterable particulate (e.g., 0.01 grains per dry standard cubic feet). The only entry for a baghouse in the RBLC was for a 30 MMBtu/hr furnace for glass melting at an insulation manufacturing facility and the unit is subject to the PM emission standards under 40 C.F.R. 63 Subpart NNN. EUs 11 and 12 are much smaller units at 5 MMBtu/hr, are used for providing space heating, and have a much lower working

[9] https://www3.epa.gov/ttn/catc/dir1/ff-shaker.pdf
https://www3.epa.gov/ttn/catc/dir1/ff-pulse.pdf
https://www3.epa.gov/ttn/catc/dir1/ff-revar.pdf

temperature. Due to the differences in size, purpose, and operating temperatures, the Department does not consider a baghouse a technically feasible control technology for the propane-fired boilers.

(d) Limited Operation
Limiting the operation of emission units reduces the potential to emit for those units. EUs 11 and 12 are the only sources of heat for the North Pole Power Plant. Therefore, it is not appropriate to limit the operation of these units. The Department does not consider the use of limited operation a technically feasible control technology for the propane-fired boilers.

(e) Good Combustion Practices
The theory of GCPs was discussed in detail in the $PM_{2.5}$ BACT section for the fuel oil-fired simple cycle gas turbines 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 propane-fired boiler.

Step 2 - Eliminate Technically Infeasible $PM_{2.5}$ technologies for the Propane-Fired Boilers
As explained in Step 1 of Section 4.5, the Department does not consider a baghouse and limited operation as technically feasible $PM_{2.5}$ control technologies. Flue gas recirculation is not recommended by the vendor as a control technology for EUs 11 and 12, and therefore is not considered a technically feasible control technology.

Step 3 - Rank the Remaining $PM_{2.5}$ Control Technologies for the Propane-Fired Boilers
GVEA has accepted the only technically feasible control technology for EUs 11 and 12. Therefore, ranking is not required.

Step 4 - Evaluate the Most Effective Controls

GVEA BACT Proposal

GVEA proposes the following as BACT for the propane-fired boilers:

(a) Burn low sulfur fuel in EUs 11 and 12;

(b) $PM_{2.5}$ emissions from EUs 11 and 12 shall not exceed 0.7 lb/1000 gal over a 4-hour averaging period; and

Department Evaluation of BACT for $PM_{2.5}$ Emissions from the Propane-Fired Boilers
The Department reviewed GVEA's proposal for EUs 11 and 12 and finds that an emission rate achievable with good combustion practices is also BACT for the propane-fired boilers.

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

(a) Burn only propane as fuel in EUs 11 and 12;

(b) $PM_{2.5}$ emissions from the operation of the propane-fired boilers shall be controlled with good combustion practices; and

(c) $PM_{2.5}$ emissions from EUs 11 and 12 shall not exceed 0.008 lb/MMBtu[10] over a 3-hour averaging period.

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 University of Alaska Fairbanks Campus.

5.1 SO_2 BACT for the Fuel Oil-Fired Simple Cycle Gas Turbines (EUs 1 and 2)

Possible SO_2 emission control technologies for the fuel oil-fired simple cycle gas turbines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 15.190 for Simple Cycle Gas Turbines (rated at 25 MW or more) The search results for simple cycle gas turbines are summarized in Table 5-1.

Table 5-1. RBLC Summary of SO_2 Controls for Fuel Oil-Fired Simple Cycle Gas Turbines

Control Technology	Number of Determinations	Emission Limits
Ultra-Low Sulfur Diesel	7	0.0015 % S by wt.
Fuel Oil (0.05 % S by wt.)	2	0.0026 – 0.055 lb/MMBtu
Good Combustion Practices	3	0.6 lb/hr

RBLC Review

A review of similar units in the RBLC indicates that limiting the sulfur content of fuel and good combustion practices are the principal SO_2 control technologies determined as BACT for fuel oil-fired simple cycle gas turbines. The lowest SO_2 emission rate listed in the RBLC is combustion of ULSD at 0.0015 % S by wt.

Step 1 - Identification of SO_2 Control Technology for the Simple Cycle Gas Turbines

From research, the Department identified the following technologies as available for control of SO_2 emissions from fuel oil-fired simple cycle gas turbines rated at 25 MW or greater:

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

(b) Low Sulfur Fuel (No. 1 Fuel Oil)
No. 1 fuel oil has a sulfur content of approximately 0.1 percent sulfur by weight. Using No. 1 fuel oil would reduce SO_2 emissions because the fuel oil-fired simple cycle gas turbines are allowed to combust standard No. 2 fuel oil that has a sulfur content of up to 0.5 percent sulfur by weight. Switching to No. 1 fuel oil could reach an 80 percent

[10] Emission factor derived from AP-42 Table 1.5-1 for propane-fired boilers (0.7 lb/1,000 gal) converted to lb/MMbtu.

decrease in SO_2 emissions from the fuel oil-fired simple cycle gas turbines during non-startup operation. The Department considers No. 1 fuel oil a technically feasible control technology for the fuel oil-fired simple cycle gas turbines.

(c) Limited Operation
Limiting the operation of emissions units reduces the potential to emit of those units. Due to EUs 1 and 2 currently operating under limits, the Department considers limited operation a technically feasible control technology for the fuel oil-fired simple cycle gas turbines.

(d) Good Combustion Practices
The theory of GCPs was discussed in detail in the $PM_{2.5}$ BACT section for the fuel oil-fired simple cycle gas turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of SO_2. The Department considers GCPs a technically feasible control technology for the fuel oil-fired simple cycle gas turbines.

Step 2 - Eliminate Technically Infeasible SO_2 Technologies for the Simple Cycle Gas Turbines
All control technologies identified are technically feasible for the fuel oil-fired simple cycle gas turbines.

Step 3 - Rank the Remaining SO_2 Control Technologies for the Simple Cycle Gas Turbines
The following control technologies have been identified and ranked for control of SO_2 from the fuel oil-fired simple cycle gas turbines:

(a)	Ultra Low Sulfur Diesel	(99.7% Control)
(b)	Low Sulfur Fuel (No. 1 Fuel Oil)	(80% Control)
(d)	Good Combustion Practices	(Less than 40% Control)
(c)	Limited Operation	(0% Control)

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

Step 4 - Evaluate the Most Effective Controls

GVEA BACT Proposal

GVEA provided an economic analysis for switching the fuel combusted in the simple cycle gas turbines to ultra-low sulfur diesel. A summary of the analyses for each of EUs 1 and 2 is shown below:

Table 5-2. GVEA Economic Analysis for Technically Feasible SO_2 Controls for EU 1

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
ULSD (0.0015 % S wt.)	1,486.4	1,481.9	$21,750,638	$20,661,330	$13,942
Capital Recovery Factor = 0.0944 (7% interest rate for a 20 year equipment life)					

Table 5-3. GVEA Economic Analysis for Technically Feasible SO_2 Controls for EU 2

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
ULSD (0.0015 % S wt.)	1,356.1	1,352.0	$8,674,362	$18,978,063	$14,037
Capital Recovery Factor = 0.0944 (7% interest rate for a 20 year equipment life)					

GVEA contends that the economic analysis indicates the level of SO_2 reduction does not justify the fuel switch to ULSD or Low Sulfur Fuel in the simple cycle turbines based on the excessive cost per ton of SO_2 removed per year.

GVEA proposes the following as BACT for SO_2 emissions from the simple cycle gas turbines:

(a) SO_2 emissions from the fuel oil-fired simple cycle gas turbines will be controlled by complying with NOx limits for EUs 1 and 2 listed in Operating Permit AQ0110TVP03 Conditions 13 and 12, respectively;

(b) SO_2 emissions from the fuel oil-fired simple cycle gas turbines will be limited by maintain good combustion practices; and

(c) Restricting the sulfur content to 500 ppm in fuel.

Department Evaluation of BACT for SO_2 Emissions from the Simple Cycle Gas Turbines

The Department revised the cost analyses provided by GVEA for the fuel switch to ULSD in the simple cycle gas turbines using an interest rate of 8.5% (current bank prime interest rate), a 30-year equipment life, and a cost range for switching from No. 2 fuel oil to ULSD of $0.185/gallon to $0.424/gallon at the North Pole Power Plant based on updated data provided by GVEA. This includes the average price per gallon difference of $0.424/gallon covering the period from January 2017 through October 2018 that was used in the Department's previous analysis, as well as an average price per gallon difference of $0.185/gallon for September 2019 through October 2020, and $0.358 for October 2021 through April 2023. Additionally, the Department reviewed the cost information provided by GVEA to appropriately evaluate the total capital investment of installing two new 1.5-million-gallon ULSD storage tanks at GVEA's North Pole Power Plant. A summary of these analyses is shown in Table 5-4 and Table 5-5.

Table 5-4. Department Economic Analysis for Technically Feasible SO_2 Controls for EU 1

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
ULSD	1,486.4	1481.9	10,875,319	9,824,223 – 20,646,731	6,629 – 13,932
Capital Recovery Factor = 0.0931 (8.5% interest rate for a 30-year equipment life)					

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

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
ULSD	1,356.1	1,352.0	10,875,319	9,089,779 – 18,963,464	6,723 – 14,026
Capital Recovery Factor = **0.0931 (8.5%** interest rate for a 30-year equipment life)					

The Department's economic analysis indicates the level of SO_2 reduction justifies the use of ULSD as BACT for the fuel oil-fired simple cycle gas turbines located in the Serious $PM_{2.5}$ nonattainment area.

Step 5 - Selection of SO_2 BACT for the Simple Cycle Gas Turbines

The Department's finding is that BACT for SO_2 emissions from the fuel oil-fired simple cycle gas turbines is as follows:

(a) SO_2 emissions from EUs 1 and 2 shall be controlled by limiting the sulfur content of fuel combusted in the turbines to no more than 0.0015 percent by weight; and

(b) Maintain good combustion practices by following the manufacturer's operating and 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 fuel oil-fired simple cycle gas turbines located in the Serious $PM_{2.5}$ nonattainment area.

Table 5-6. Comparison of SO_2 BACT for Simple Cycle Gas Turbines at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
GVEA – North Pole	Two Fuel Oil-Fired Simple Cycle Gas Turbines	1,344 MMBtu/hr	0.0015 % S wt.	ULSD Good Combustion Practices
GVEA – Zehnder	Two Fuel Oil-Fired Simple Cycle Gas Turbines	536 MMBtu/hr	0.0015 % S wt.	ULSD Good Combustion Practices

5.2 SO_2 BACT for the Fuel Oil-Fired Combined Cycle Gas Turbines (EUs 5 and 6)

Possible SO_2 emission control technologies for the fuel oil-fired combined cycle gas turbines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 15.290 for Liquid Fuel-Fired Combined Cycle Gas Turbines rated at 25 MW or more. The search results for combined cycle gas turbines are summarized in Table 5-7.

Table 5-7. RBLC Summary of SO_2 Control for Oil-Fired Combined Cycle Gas Turbines

Control Technology	Number of Determinations	Emission Limits
Ultra-Low Sulfur Diesel	1	6.7 lb/hr

RBLC Review
A review of similar units in the RBLC indicates combustion of ultra-low sulfur diesel is the principal SO_2 control technology installed on fuel oil-fired combined cycle gas turbines. The SO_2 emission rate listed in the RBLC is 6.7 lb/hr.

Step 1 - Identification of SO_2 Control Technology for the Combined Cycle Gas Turbines
From research, the Department identified the following technologies as available for the control of SO_2 emissions from the fuel oil-fired combined cycle gas turbines:

(a) Ultra-Low Sulfur Diesel
The theory of ULSD was discussed in detail in the SO_2 BACT for the fuel oil-fired simple cycle turbines and will not be repeated here. The Department considers ULSD a technically feasible control technology for the fuel oil-fired combined cycle gas turbines.

(b) Light Straight Run Turbine Fuel (LSR)
EU 5 typically combusts LSR when not in startup. EU 6 will also combust LSR when not in startup when installed. The sulfur content of the LSR is limited to no more than 0.05 percent by weight as required by Condition 15.1 of Operating Report AQ0110TVP03. The Department considers operating LSR a technically feasible control technology for the fuel oil-fired combined cycle gas turbines.

(c) Low Sulfur Fuel
The theory of low sulfur fuel was discussed in detail in the SO_2 BACT for the fuel oil-fired simple cycle turbines and will not be repeated here. The Department considers low sulfur fuel a technically feasible control technology for the fuel oil-fired combined cycle gas turbines.

(d) Limited Operation
Limiting the operation of emissions units reduces the potential to emit of those units. Due to EUs 5 and 6 currently operating under limits, the Department considers limited operation a technically feasible control technology for the fuel oil-fired simple cycle gas turbines.

(e) Good Combustion Practices
The theory of GCPs was discussed in detail in the $PM_{2.5}$ BACT section for the fuel oil-fired combined cycle gas turbines 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 fuel oil-fired combined cycle gas turbines.

Step 2 - Eliminate Technically Infeasible SO_2 Technologies for the Combined Cycle Gas Turbines
All control technologies identified are technically feasible for the fuel oil-fired combined cycle gas turbines.

Step 3 - Rank the Remaining SO_2 Control Technologies for the Combined Cycle Gas Turbines
The following control technologies have been identified and ranked by efficiency for control of SO_2 emissions from the fuel oil-fired combined cycle gas turbines:

(a) Ultra-Low Sulfur Diesel (50% Control)
(e) Good Combustion Practices (Less than 40% Control)
(b) Light Straight Run Turbine Fuel (0% Control)
(d) Limited Operation (0% Control)
(c) Low Sulfur Fuel (0% Control)

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

Low sulfur fuel is listed as 0% control as it has the same fuel sulfur content requirements as the light straight run turbine fuel that is currently combusted in the fuel oil-fired combined cycle gas turbines.

Step 4 - Evaluate the Most Effective Controls

GVEA BACT Proposal

GVEA provided an economic analysis for switching the fuel combusted in the combined cycle gas turbines to ultra-low sulfur diesel. A summary of the analyses for EUs 5 and 6 is shown below:

Table 5-8. GVEA Economic Analysis for Technically Feasible SO_2 Control for EUs 5 and 6

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
ULSD	6.0	3.0	--	$34,247,220	$11,415,740
Capital Recovery Factor = 0.1424 (7% interest rate for a 10 year equipment life)					

GVEA contends that the economic analysis indicates the level of SO_2 reduction does not justify the use of ULSD or low sulfur fuel based on the excessive cost per ton of SO_2 removed per year.

GVEA proposes the following as BACT for SO_2 emissions from the combined cycle gas turbines:

(a) SO_2 emissions from EUs 5 and 6 shall combust Light Straight Run Turbine Fuel (30 ppm S in fuel)

Department Evaluation of BACT for SO_2 Emissions from the Combined Cycle Gas Turbines

The Department revised the cost analysis provided for the fuel switch to ULSD in the combined cycle gas turbines by splitting apart normal operations which consume LSR with a maximum sulfur content of 0.005 % by weight, and startup operations which already use ULSD, the top SO_2 control, and therefore do not require an economic analysis. For normal operations, the Department used data provided by GVEA for the difference in the average fuel cost between ULSD and LSR Naphtha delivered to the North Pole Power Plant between January 2017 through October 2018 ($1.117/gallon) and January 2019 through October 2020 ($0.588/gal). Since there is no capital cost involved with the fuel switch to ULSD, the only value driving the cost for the evaluation was the cost difference in the fuel prices between the fuel types which is shown as a range. A summary of the analysis for the two turbines under normal operations is shown in Table 5-9:

Table 5-9. Department Economic Analysis for Technically Feasible SO_2 Controls for Turbines Under Normal Operations

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
ULSD	9.5	6.7	--	17,085,516 – 32,456,669	2,559,025 – 4,861,277
Capital Recovery Factor = 0.0931 (8.5% interest rate for a 30-year equipment life)					

The Department's economic analysis indicates the level of SO_2 reduction does not justify the use of ULSD as BACT during normal operations for the fuel oil-fired combined cycle gas turbines located in the Serious $PM_{2.5}$ nonattainment area. However, the Department notes that according to assessable emissions data submitted to the Department by GVEA, EU 5 (currently the only installed EU in the group) has already been combusting ULSD exclusively during startup for at least the past 5 calendar years (2023-2019).

Step 5 - Selection of SO_2 BACT for the Combined Cycle Gas Turbines

The Department's finding is that BACT for SO_2 emissions from the fuel oil-fired combined cycle gas turbines is as follows:

(a) Except during startup, SO_2 emissions from EUs 5 and 6 shall be controlled by limiting the fuel combusted in the turbines to light straight run turbine fuel (50 ppmw S in fuel);

(b) During startup, SO_2 emission from EUs 5 and 6 shall be controlled by limiting the sulfur content of fuel combusted in the turbines to no more than 0.0015 percent by weight (ULSD); and

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

5.3 SO_2 BACT for the Large Diesel-Fired Engine (EU 7)

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 5-10.

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

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

RBLC Review
A review of similar units in the RBLC indicates combustion of low sulfur fuel, limited operation, good combustion practices, and compliance with the federal emission standards are the principal 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 Engine
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 fuel oil-fired simple cycle gas turbines and will not be repeated here. The Department considers ULSD a technically feasible control technology for the large diesel-fired engine.

(b) Federal Emission Standards
The theory of federal emission standards was discussed in detail in the $PM_{2.5}$ BACT section for the large diesel-fired engine and will not be repeated here. The Department does not consider federal emission standards a feasible control technology for the large diesel-fired engine.

(c) Limited Operation
Limiting the operation of emissions units reduces the potential to emit of those units. The Department considers limited operation as a technically feasible control technology for the large diesel-fired engine.

(d) Good Combustion Practices
The theory of GCPs was discussed in detail in the $PM_{2.5}$ BACT section for the fuel oil-fired simple cycle turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of NOx emissions. The Department considers GCPs a technically feasible control technology for the large diesel-fired engine.

Step 2 - Eliminate Technically Infeasible SO_2 Control Technologies for the Large Engine
As explained in Step 1 of Section 5.3, the Department does not consider federal emission standards a technically feasible control technology to control SO_2 emissions from the large diesel-fired engine.

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

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

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

Step 4 - Evaluate the Most Effective Controls

GVEA BACT Proposal

GVEA provided an economic analysis of the control technologies available for the large diesel-fired engine to demonstrate that the use of ULSD with limited operation is not economically feasible on these units. A summary of the analysis for EU 7 is shown below:

Table 5-11. GVEA Economic Analysis for Technically Feasible SO_2 Controls

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
ULSD	0.01005	0.0099	--	$444	$45,072
Capital Recovery Factor = 0.1424 (7% interest rate for a 10 year equipment life)					

GVEA contends that the economic analysis indicates the level of SO_2 reduction does not justify the use of ULSD based on the excessive cost per ton of SO_2 removed per year.

GVEA proposed the following as BACT for SO_2 emissions from the diesel-fired engine:

(a) SO_2 emissions from the large diesel-fired engine shall not exceed 0.05 weight percent sulfur; and

(b) Maintain good combustion practices.

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

The Department reviewed GVEA's proposal for the large diesel-fired engine and revised the cost analysis for the fuel switch to ULSD. The Department used the difference in the average fuel cost between ULSD versus No. 1 fuel oil delivered to the North Pole Power Plant between January 2019 through October 2020, of $0.223/gallon and between October 2021 and April 2023, of $0.651/gallon. For baseline emissions, the Department used the existing fuel sulfur limit of 0.1 percent by weight contained in Condition 5 of Construction Permit AQ0110CPT01, March

3, 2006 (incorporated into Operating Permit AQ0110TVP04 Rev. 1 as Condition 15), as well as the existing 52-hour yearly limit from Conditions 6 and 15 of the construction and operating permit, respectively. Since there is no capital cost involved with the fuel switch from fuel oil with a sulfur content of 0.1 percent by weight to ULSD, the only value driving the cost for the evaluation was the yearly cost difference in the fuel prices between the two fuel types. A summary of the analysis for the large diesel-fired engine is shown below in Table 5-12.

Table 5-12. Department Economic Analysis for Technically Feasible SO_2 Controls

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
ULSD	0.0118	0.0116	--	444 – 1,083	38,150 – 93,086
Capital Recovery Factor = 0.0931 (8.5% interest rate for a 30-year equipment life)					

The Department's economic analysis indicates the level of SO_2 reduction does not justify the use of ULSD as BACT for the large diesel fired engine located in the Serious $PM_{2.5}$ nonattainment area.

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

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

(a) SO_2 emissions from EU 7 shall be controlled by combusting fuel that does not exceed 0.05 weight percent sulfur (500 ppmw) at all times the unit is in operation;

(b) SO_2 emissions from EU 7 shall be controlled by limiting operation to no more than 52 hours per 12 month rolling period; and

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

The following table lists the proposed BACT determination for this facility along with those for other diesel-fired engines rated at more than 500 hp in the Serious $PM_{2.5}$ nonattainment area.

Table 5-13. 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	Limited Operation **Low Sulfur Diesel** Good Combustion Practices

Facility	Process Description	Capacity	Limitation	Control Method
GVEA Zehnder	2 Large Diesel-Fired Engines	11,000 hp	15 ppmw S in fuel	Limited Non-Emergency Operation Good Combustion Practices Ultra-Low Sulfur Diesel

5.4 SO_2 BACT for the Propane-Fired Boilers (EUs 11 and 12)

Possible SO_2 emission control technologies for the propane-fired boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 13.310, Gas-Fired Boilers (<100 MMBtu/hr). The search results for gas-fired boilers are summarized in Table 5-14.

Table 5-14. SO_2 Control for Gas-Fired Boilers with a Rating < 100 MMBtu/hr

Control Technology	Number of Determinations	Emission Limits
Low Sulfur Fuel	6	0.03 – 0.12 lb/hr
Good Combustion Practices	4	0.0048 – 0.6 lb/MMBtu
Pipeline Quality Natural Gas	28	0.0006 – 0.0048 lb/MMBtu
No Control Specified	4	0.0021 lb/MMBtu

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

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

(a) Low Sulfur Fuel
The theory of low sulfur fuel was discussed in detail in the $PM_{2.5}$ BACT for the propane-fired boilers and will not be repeated here. The Department considers low sulfur fuel a technically feasible control technology for the propane-fired boilers.

(b) Good Combustion Practices
The theory of GCPs was discussed in detail in the $PM_{2.5}$ BACT section for the fuel oil-fired simple cycle gas turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of SO_2. The Department considers GCPs a technically feasible control technology for the propane-fired boilers.

Step 2 - Eliminate Technically Infeasible SO_2 Technologies for the Propane-Fired Boilers
All identified control devices are technically feasible technologies for the propane-fired boilers.

Step 3 - Rank the Remaining SO_2 Control Technologies for the Propane-Fired Boilers
GVEA has accepted the only technically feasible control technology for the propane-fired boilers. Therefore, ranking is not required.

Step 4 - Evaluate the Most Effective Controls

GVEA BACT Proposal

GVEA proposed the following as BACT for SO_2 emissions from the propane-fired boilers:

(a) SO_2 emissions from the operation of the propane-fired boilers shall be controlled by using low sulfur fuel at all times of operation.

(b) SO_2 emissions from the propane-fired boilers shall not exceed 0.0012 lb/kgal over a 4-hour averaging period.

Department Evaluation of BACT for SO_2 Emissions from the Propane-Fired Boilers

The Department reviewed GVEA's proposal for the propane-fired boilers and finds that the SO_2 emission rate provided by GVEA was erroneously calculated. The Department used AP-42 Table 1.5-1 emission factor for propane combustion (0.10S lb/1,000 gal, where S = gr/100 scf) and using the existing sulfur limit in Condition 11 of the stationary source's Operating Permit AQ0110TVP03 (120 ppmv) The Department corrected this emission factor to 0.75 lb/1,000 gal, assuming 16 ppmv sulfur = 1 gr/100 scf.

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

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

(a) SO_2 emissions from EUs 11 and 12 shall be controlled by only combusting gas fuel (propane) with a total sulfur content of no more than 120 ppmv, or direct emissions of 0.75 lb/1,000 gal; and

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

6. BACT DETERMINATION SUMMARY

Table 6-1. NOx BACT Limits

EU ID	Description	Capacity	BACT Limit	BACT Control
All	N/A	N/A	EPA approved a comprehensive precursor demonstration for NOx See details in the Section 1 Introduction	

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

EU ID	Description	Capacity	BACT Limit (*)	BACT Control
1	Fuel Oil-Fired Simple Cycle Gas Turbine	672 MMBtu/hr	0.012 lb/MMBtu	Low Ash Fuel Limited Operation Good Combustion Practices
2	Fuel Oil-Fired Simple Cycle Gas Turbine	672 MMBtu/hr	0.012 lb/MMBtu	
5	Fuel Oil-Fired Combined Cycle Gas Turbine	455 MMBtu/hr	0.012 lb/MMBtu	Limited Operation Good Combustion Practices
6	Fuel Oil-Fired Combined Cycle Gas Turbine	455 MMBtu/hr	0.012 lb/MMBtu	
7	Large Diesel-Fired Engine	619 hp	0.32 g/hp-hr	Limited Operation Positive Crankcase Ventilation Good Combustion Practices
11	Propane-Fired Boiler	5.0 MMBtu/hr	0.008 lb/MMBtu	Propane as Fuel Good Combustion Practices
12	Propane-Fired Boiler	5.0 MMBtu/hr	0.008 lb/MMBtu	

(*) 3-hour average

Table 6-3. SO_2 BACT Limits

EU ID	Description	Capacity	BACT Limit	BACT Control
1	Fuel Oil-Fired Simple Cycle Gas Turbine	672 MMBtu/hr	15 ppmw S in fuel	Ultra-Low Sulfur Diesel Good Combustion Practices
2	Fuel Oil-Fired Simple Cycle Gas Turbine	672 MMBtu/hr	15 ppmw S in fuel	
5	Fuel Oil-Fired Combined Cycle Gas Turbine	455 MMBtu/hr	50 ppmw S in fuel (Normal Ops) 15 ppmw S in fuel (Start-Up)	Light Straight Run Turbine Fuel for Normal Operations ULSD for Start-Up Good Combustion Practices
6	Fuel Oil-Fired Combined Cycle Gas Turbine	455 MMBtu/hr	50 ppmw S in fuel (Normal Ops) 15 ppmw S in fuel (Start-Up)	
7	Large Diesel-Fired Engine	619 hp	500 ppmw S in fuel	Limited Operation Good Combustion Practices Low Sulfur Fuel
11	Propane-Fired Boiler	5.0 MMBtu/hr	N/A	Propane as Fuel Good Combustion Practices
12	Propane-Fired Boiler	5.0 MMBtu/hr		

Stationary Source: North Pole Power Plant

Emission Units: EU IDs 1 and 2 (672 MMBtu/hr (60.5 MW) Simple Cycle Turbines)

Pollutant of Concern: SO_2	
BACT Measure	**Monitoring, Recordkeeping and Reporting Requirements** Error! Bookmark not defined.
Combust Only Ultra Low Sulfur fuel at no more than 0.0015 percent sulfur by weight	• For each shipment of fuel, test sulfur content or keep receipts that specify fuel grade date, and quantity of fuel received. Keep records of the results of sulfur content tests and receipts for fuel shipments. • Include in each semi-annual operating report required by the Operating Permit, a summary of fuel test results or fuel grade shipping receipts received during the reporting period.
Good Combustion Practices	• Perform regular maintenance according to the manufacturer's and the operator's maintenance requirements and procedures. • Keep records of any maintenance that would have a significant effect on emissions. The records may be kept in electronic format. • Keep a copy of the manufacturer's and the operator's maintenance procedures. • Report a summary of the maintenance records. • Operate the EUs consistent with manufacturer's recommended combustion settings or those established during the source test conducted to demonstrate compliance with the BACT emissions limit.

Emission Units: EU IDs 5 and 6 (455 MMBtu/hr (43 MW) Combined Cycle Turbines)

BACT Measure	Monitoring, Recordkeeping and Reporting Requirements Error! Bookmark not defined.
Combust Only Ultra Low Sulfur fuel during startup	• For each shipment of fuel, test the sulfur content or keep receipts that specify fuel grade date, and quantity of fuel received. Keep records of the results of sulfur content tests and receipts for fuel shipments. • Include in each semi-annual operating report required by the Operating Permit, a summary of fuel test results or fuel grade shipping receipts from the reporting period.
Except during startup, limit sulfur content in fuel to 50 ppmw	• For each shipment of fuel, test the sulfur content or keep receipts that specify fuel grade and date Keep records of the results of sulfur content tests and receipts for fuel shipments. • Include in each semi-annual operating report, a summary of fuel test results or fuel grade shipping receipts from the reporting period.
Good Combustion Practices	• Perform regular maintenance according to the manufacturer's and the operator's maintenance requirements and procedures. • Keep records of any maintenance that would have a significant effect on emissions. The records may be kept in electronic format. • Keep a copy of the manufacturer's and the operator's recommended maintenance procedures. • Report a summary of the maintenance records.

Emission Unit: EU ID 7 (400 kW Emergency Diesel Engine)

Pollutant of Concern: SO_2	
BACT Measure	**Monitoring, Recordkeeping and Reporting Requirements** Error! Bookmark not defined.
Limit the sulfur content of the fuel combusted to 0.05 weight percent	• For each shipment of fuel combusted in EU ID 7, keep receipts that specify fuel grade, date, and quantity of fuel received. • Include in each semi-annual operating report required by the Operating Permit a summary of the fuel grade shipping receipts received during the reporting period.
Good Combustion Practices	• Perform records of maintenance conducted on emissions units to comply with this BACT measure. • Keep records of any maintenance that would have a significant effect on emissions. The records may be kept in electronic format. • Keep a copy of the manufacturer's and the operator's recommended maintenance procedures. • Report a summary of the maintenance that would have a significant effect on emissions in each operating report.
Limit operation to no more than 52 hours per 12 month rolling period	• Demonstrate compliance by complying with Condition 7.1b of Minor Permit AQ0110MSS01 Rev. 1.

Emission Units: EU IDs 11 and 12 (5.0 MMBtu/hr Boilers)

Pollutant of Concern: SO_2	
BACT Measure	**Monitoring, Recordkeeping and Reporting Requirements** Error! Bookmark not defined.
Combust only propane	• For each shipment of fuel, keep receipts that specify the date, type, and quantity of fuel received. Keep records of the receipts for fuel shipments. • Alternatively, conduct a stack test to directly measure SO_2 emissions and report results in lb/1,000 gal of fuel combusted. • Include in each semi-annual operating report required by the Operating Permit, a summary of the types of fuel received or shipping receipts from the reporting period.
Good Combustion Practices	• Perform regular maintenance according to the manufacturer's and the operator's maintenance requirements and procedures. • Keep records of any maintenance that would have a significant effect on emissions. The records may be kept in electronic format. • Keep a copy of the manufacturer's and the operator's maintenance procedures. • Report a summary of the maintenance records.

DEPARTMENT OF ENVIRONMENTAL CONSERVATION
AIR QUALITY CONTROL MINOR PERMIT

Minor Permit: **AQ0110MSS01 Revision 1** **Final Date – October 30, 2024**
Rescinds Permit: **AQ0110MSS01**

The Alaska Department of Environmental Conservation (Department), under the authority of AS 46.14 and 18 AAC 50, issues Air Quality Control Minor Permit to the Permittee listed below.

Permittee: **Golden Valley Electric Association**
PO Box 71249
Fairbanks, AK 99707

Stationary Source: **North Pole Power Plant**

Location: North Pole, Alaska
Latitude: 64.7344° North; Longitude: 147.3453° West

Project: $PM_{2.5}$ Serious Nonattainment State Implemtation Plan (SIP)

Permit Contact: Naomi Morton Knight, P.E.
907-458-4557
NMKnight@gvea.com

The Permittee submitted an application for Minor Permit AQ0110MSS01 under AS 46.14.130(c)(2) because the Department found that public health or air quality effects provided a reasonable basis to regulate the stationary source. This finding is contained in the State Air Quality Control Plan adopted on November 19, 2019.

With the issuance of AQ0110MSS01 Revision 1, The Department finds that public health or air quality effects still provide a reasonable basis to regulate the stationary source under AS 46.14.130(c)(2). This finding is contained in the State Air Quality Control Plan adopted on November 19, 2019, for the $PM_{2.5}$ Serious Nonattainment area.

This permit satisfies the obligation of the Permittee to obtain a minor permit under 18 AAC 50. As required by AS 46.14.120(c), the Permittee shall comply with the terms and conditions of this permit.

Conditions 6 through 6.2 and 16 through 16.4b of Construction Permit AQ0110CPT01 Rev. 1 have been adopted into this minor permit.

for:

James R. Plosay, Manager
Air Permits Program

Table of Contents

Abbreviations and Acronyms

AAC....................Alaska Administrative Code
AAAQS ....Alaska Ambient Air Quality Standards
ADEC ....Alaska Department of Environmental Conservation
AOS ....Air Online Services
AS ....Alaska Statutes
ASTM ....American Society for Testing and Materials
BACM ....Best Available Control Measures
BACT ....Best Available Control Technology
bhp ....Brake Horsepower
CAA....................Clean Air Act
CDX....................Central Data Exchange
CEDRI ....Compliance and Emissions Data Reporting Interface
CEMS ....Continuous Emissions Monitoring System
CFR. ....Code of Federal Regulations
CMS....................Continuous Monitoring System
CO ....Carbon Monoxide
CO_2e ....CO_2-equivalent
dscf ....Dry Standard Cubic Foot
EPA ....US Environmental Protection Agency
EU.......................Emissions Unit
EU ID(s) ....Emissions Unit Identification Number(s)
GHG ....Greenhouse Gas
gph ....Gallons Per Hour
gr/dscf.................Grain per Dry Standard Cubic Foot (1 pound = 7000 grains)
GVEA ....Golden Valley Electric Association
HAPs ....Hazardous Air Pollutants [as defined in AS 46.14.990]
hp ....Horsepower
kW ....Kilowatt
LAER..................Lowest Achievable Emission Rate
MACT ....Maximum Achievable Control Technology [as defined in 40 C.F.R. 63]
MMBtu/hr...........Million British Thermal Units per Hour
MMscf ....Million Standard Cubic Feet
MR&R ....Monitoring, Recordkeeping, and Reporting
NA ....Not Applicable
NAICS ....North American Industrial Classification System
NESHAPs............National Emission Standards for Hazardous Air Pollutants [as contained in 40 C.F.R. 61 and 63]
NH_3......................Ammonia
NOx ....Nitrogen Oxides
NSPS ....New Source Performance Standards [as contained in 40 C.F.R. 60]
O_2..........................Oxygen
ORL......................Owner Requested Limit
PAL ....Plantwide Applicability Limitation
Pb..........................Lead
$PM_{2.5}$.....................Particulate Matter [2.5 nominal microns or less in diameter]
PM_{10} ....Particulate Matter [10 nominal microns or less in diameter]
ppm ....Parts Per Million
ppmv, ppmvd........Parts Per Million by Volume on a Dry Basis
ppmw ……………Parts Per Million by Weight
psia ....Pounds per Square Inch (Absolute)
PSD ....Prevention of Significant Deterioration
PTE.......................Potential To Emit
SIC........................Standard Industrial Classification
SIP ....State Implementation Plan
SO_2 ....Sulfur Dioxide
SPC.......................Standard Permit Condition or Standard Operating Permit Condition
TPY ....Tons Per Year
ULSD ....Ultra-Low Sulfur Diesel
VOC ....Volatile Organic Compound [as defined in 40 C.F.R. 51.100(s)]
VOL......................Volatile Organic Liquid [as defined in 40 C.F.R. 60.111b, Subpart Kb]
vol% ....Volume Percent
wt% ....Weight Percent
$wt\%S_{fuel}$ ....Weight Percent of Sulfur in Fuel

Section 1 Emissions Unit Inventory

Emissions Unit (EU) Authorization. The Permittee is authorized to install and operate the EUs listed in Table 1 in accordance with the minor permit application and the terms and conditions of this permit. The information in Table 1 is for identification purposes only, unless otherwise noted in the permit. The specific EU descriptions do not restrict the Permittee from replacing an EU identified in Table 1.

Table 1 – EU Inventory

EU ID	Emissions Unit Name	Emissions Unit Description	Fuel	Rating/Size	Installation or Construction Date
1	GT#1	GE Frame 7, Series 7001 Regenerative Gas Turbine	Fuel Oil	672 MMBtu/hr (60.5 MW)	1976
2	GT#2	GE Frame 7, Series 7001 Regenerative Gas Turbine	Fuel Oil	672 MMBtu/hr (60.5 MW)	1977
5	GT#3	GE LM6000PC Gas Turbine (water injection for NO_x control) (oxidation catalyst for CO control)	Naphtha/LSR Jet A	455 MMBtu/hr (43 MW, nominal)	2005
6	GT#4	GE LM6000PC Gas Turbine (water injection for NO_x control) (oxidation catalyst for CO control)	Naphtha/LSR Jet A	455 MMBtu/hr (43 MW, nominal)	Not Installed
7	Emergency Generator	Mitsubishi Engine #0A8829 (Generac Gen Set #5231150100)	Fuel Oil	565 hp	2005
11	Building Boiler	Bryan Steam RV500 Boiler	Propane	5.0 MMBtu/hr	2005
12	Building Boiler	Bryan Steam RV500 Boiler	Propane	5.0 MMBtu/hr	2005

1. The Permittee shall comply with all applicable provisions of AS 46.14 and 18 AAC 50 when installing a replacement EU, including any applicable minor or construction permit requirements**.**

Section 3 State Implementation Plan (SIP) Requirements

Fairbanks $PM_{2.5}$ Serious Nonattainment Area SIP Requirements

5. Simple Cycle Turbine Emissions Limit. The Permittee shall limit the emissions form the simple cycle gas tubrine EU IDs 1 and 2 as specified in Table 2.

Table 2 - EU IDs 1 and 2 SIP BACT Limits

Pollutant	BACT Control	Fuel Type	BACT Emissions Limit
$PM_{2.5}$	Good Combustion Practices and Limited Operation	Low Ash (Distillate) Fuel	0.012 lb/MMBtu (3-hour average)

5.1 For EU IDs 1 and 2, the Permittee shall:

a. Conduct an initial source test on either EU ID 1 or 2 in accordance with Section 6, within 12 months of permit issuance, to demonstrate compliance with the $PM_{2.5}$ emissions limit listed in Table 2.

(i) Conduct the source test, in accordance with the procedures specified in 40 CFR 51, Appendix M, Method 201A and, if applicable, Method 202 as provided in Method 201A, for at least three loads representative of the normal operating range of the EU. The Permittee may perform testing at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice.

(ii) Emission results shall be reported as the arithmetic 3-hour average of all valid test runs and shall be in units of lb/MMBtu.

(iii) The Permittee shall report the results of the source test in accordance with Condition 27.

(iv) Include the following in the next operating report in accordance with Condition 12, that is due after the submittal date of the initial source test report:

(A) a summary of the source test results; and

(B) relevant combustion settings (including but not limited to average CO and O_2 concentrations in the flue gas) established during the source test that demonstrates compliance with the BACT $PM_{2.5}$ emissions limit in Table 2.

b. Report the compliance status with the $PM_{2.5}$ emissions limit in Table 2 in accordance with each annual compliance certification described in Condition 13.

c. Combust only low ash (distillate) fuel.

(i) For each shipment of fuel, keep receipts that specify the fuel grade and amount.

(ii) Include copies of the records required by Condition 5.1c(i) for the reporting period, in each operating report required by Condition 12.

d. Maintain good combustion practices at all times the EUs are in operation.

(i) Perform regular maintenance according to the manufacturer's and the operator's maintenance requirements and procedures.

(ii) Keep records of any maintenance that would have a significant effect on emissions. The records may be kept in electronic format.

(iii) Keep a copy of the manufacturer's and the operator's maintenance procedures.

(iv) Include a summary of the maintenance records collected under Condition 5.1d(ii) for the reporting period, in each operating report required by Condition 12.

(v) Operate the EUs consistent with manufacturer's recommended combustion settings (e.g., maximum CO, excess air in flue gas, and other relevant parameters) or those established during the source test conducted to demonstrate compliance with the BACT emissions limit in Table 2.

(A) For each of EU IDs 1 and 2, measure and record the CO and O_2 concentrations in the exhaust stream using a portable handheld combustion analyzer during or within 30 days after the end of a calendar quarter that the EU operates.[1]

(B) Include copies of the records required by Condition 5.1d(v)(A) for the reporting period, in each operating report required by Condition 12.

e. Report in accordance with Condition 11, whenever

(i) an emissions rate determined by the source test required by Condition 5.1a exceeds the limit in Table 2; or

(ii) any of Conditions 5.1a through 5.1d are not met.

5.2 For EU ID 1, the Permittee shall comply with Condition 6.2.

5.3 For EU ID 2, the Permittee shall operate no more than 7,992 hours in any consecutive 12-month rolling period.

a. On or before the 15^{th} of each month

[1] It is not the Department's intention to require the Permittee to start up an EU just to perform the CO and O_2 concentration measurements.

(i) Record the hours of operation for EU ID 2 for the previous calendar month, and

(ii) Calculate and record the rolling 12-month hours of operation for EU ID 2.

b. Report in accordance with Condition 11 whenever the total operating hours of EU ID 2 exceeds 7,992 hours in a 12-consecutive month period.

c. Include copies of the records required under Condition 5.3a(ii) in the operating report required under Condition 12 for the period covered by the report.

6. **Combined Cycle Turbine Emissions Limit.** The Permittee shall limit the emissions from the gas turbine EU IDs 5 and 6 as specified in Table 3.

Table 3 - EU IDs 5 and 6 SIP BACT Limits

Pollutant	BACT Contol	BACT Emissions Limit
$PM_{2.5}$	Good Combustion Pratices and Limited Operation	0.012 lb/MMBTU (3-hour average)

6.1 For EU IDs 5 and 6, the Permittee shall:

a. Conduct an initial source test on either EU ID 5 or 6 in accordance with Section 6, within 12 months of permit issuance, to demonstrate compliance with the $PM_{2.5}$ emissions limit listed in Table 3.

(i) Conduct the source test, in accordance with the procedures specified in 40 CFR 51, Appendix M, Method 201A and, if applicable, Method 202 as provided in Method 201A, for at least three loads representative of the normal operating range of the EU. The Permittee may perform testing at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice.

(ii) Emission results shall be reported as the arithmetic 3-hour average of all valid test runs and shall be in units of lb/MMBtu.

(iii) The Permittee shall report the results of the source test in accordance with Condition 27.

(iv) Include the following in the next operating report in accordance with Condition 12, that is due after the submittal date of the initial source test report:

(A) a summary of the source test results; and

(B) relevant combustion settings (including but not limited to average CO and O_2 concentrations in the flue gas) established during the source test that demonstrates compliance with the BACT $PM_{2.5}$ emissions limit in Table 3.

b. Report the compliance status with the $PM_{2.5}$ emissions limit in Table 3 in accordance with each annual compliance certification described in Condition 13.

c. Maintain good combustion practices at all times the EUs are in operation.

(i) Perform regular maintenance according to the manufacturer's and the operator's maintenance requirements and procedures.

(ii) Keep records of any maintenance that would have a significant effect on emissions. The records may be kept in electronic format.

(iii) Keep a copy of the manufacturer's and the operator's maintenance procedures.

(iv) Include a summary of the maintenance records collected under Condition 6.1c(ii) for the reporting period, in each operating report required by Condition 12.

(v) Operate the EUs consistent with manufacturer's recommended combustion settings (e.g., maximum CO, excess air in flue gas, and other relevant parameters) or those established during the source test conducted to demonstrate compliance with the BACT emissions limit in Table 3.

(A) For each of EU IDs 5 and 6, measure and record the CO and O_2 concentrations in the exhaust stream using a portable handheld combustion analyzer during or within 30 days after the end of a calendar quarter that the EU operates.[2]

(B) Include copies of the records required by Condition 6.1c(v)(A) for the reporting period, in each operating report required by Condition 12.

d. Report in accordance with Condition 11, whenever

(i) an emissions rate determined by the source test required by Condition 6.1a exceeds the limit in Table 3; or

(ii) any of Conditions 6.1a through 6.1c are not met.

6.2 For EU IDs 1, 5, and 6, the Permittee shall comply with Conditions 16.1 through 16.4 of Construction Permit AQ0110CPT01 Rev. 1, issued March 3, 2006.

7. **Emergency Diesel Engine Emissions Limit.** The Permittee shall limit the emissions form the emergency diesel engine EU ID 7 as specified in Table 4.

[2] It is not the Department's intention to require the Permittee to start up an EU just to perform the CO and O_2 concentration measurements.

Table 4 - EU ID 7 SIP BACT Limit

Pollutant	BACT Control	BACT Emissions Limit
$PM_{2.5}$	Good Combustion Practices Limited Operation Positive Crankcase Ventilation	0.32 g/hp-hr (3-hour average)

7.1 For EU ID 7, the Permittee shall demonstrate compliance with the $PM_{2.5}$ BACT emissions limit contained in Table 4 as follows:

a. Maintain good combustion practices at all times the EU is in operation.

(i) Perform regular maintenance according to the manufacturer's and the operator's maintenance requirements and procedures.

(ii) Keep records of any maintenance that would have a significant effect on emissions. The records may be kept in electronic format.

(iii) Keep a copy of the manufacturer's and the operator's maintenance procedures.

b. Limit the operation of the EU to 52 hours per 12-month rolling period.

(i) Demonstrate compliance by complying with Conditions 6 through 6.2 of Construction Permit AQ0110CPT01 Rev. 1.

c. Maintain a positive crankcase ventilation (PCV) system at all times the EU operates in accordance with the manufacturer's and operator's recommended operating and maintenance procedures.

(i) Submit an initial certification that the PCV system listed in Table 4 has been installed or is an inherent design to the EU, in the first operating report due after permit issuance, as required by Condition 12.

d. Report in accordance with Condition 12

(i) a summary of the maintenance records collected under Condition 7.1a(ii); and

(ii) the operating hour records collected under Condition 7.1b(i)(B)(2).

e. Report the compliance status with the $PM_{2.5}$ emissions limit in Table 4 in accordance with each annual compliance certification described in Condition 13.

f. Report in accordance with Condition 11, whenever

(i) an emissions rate exceeds the limit in Table 4; or

(ii) any of Conditions 7.1a through 7.1e are not met.

8. **Boiler Emissions Limit.** The Permittee shall limit the emissions form the boiler EU IDs 11 and 12 as specified in Table 5.

Table 5 - EU IDs 11 and 12 SIP BACT Limits

Pollutant	BACT Control	Fuel Type	BACT Emissons Limit
$PM_{2.5}$	Good Combustion Practices Combust only Propane	Propane	0.008 lb/MMBTU (3-hour average)

8.1 For EU IDs 11 and 12, the Permittee shall demonstrate compliance with the $PM_{2.5}$ BACT emissions limit contained in Table 5 as follows:

a. Maintain good combustion practices at all times the EUs are in operation.

(i) Perform regular maintenance according to the manufacturer's and the operator's maintenance requirements and procedures.

(ii) Keep records of any maintenance that would have a significant effect on emissions. The records may be kept in electronic format.

(iii) Keep a copy of the manufacturer's and the operator's maintenance procedures.

b. Combust only gas fuel (propane).

(i) For each shipment of fuel, keep receipts that specify the date, type,and quantity of fuel received .

c. Report in accordance with Condition 12

(i) a summary of the maintenance records collected under Condition 8.1a(ii); and

(ii) a summary of the types of fuel received or shipping receipts collected under Condition 8.1b(i).

d. Report the compliance status with the $PM_{2.5}$ emissions limit in Table 5 in accordance with each annual compliance certification described in Condition 13.

e. Report in accordance with Condition 11, whenever

(i) an emissions rate exceeds the limit in Table 5; or

(ii) any of Conditions 8.1a through 8.1d are not met.

Section 4 Recordkeeping, Reporting, and Certification Requirements

9. Certification. The Permittee shall certify any permit application, report, affirmation, or compliance certification submitted to the Department and required under the permit by including the signature of a responsible official for the permitted stationary source following the statement: "*Based on information and belief formed after reasonable inquiry, I certify that the statements and information in and attached to this document are true, accurate, and complete.*" Excess emissions reports must be certified either upon submittal or with an operating report required for the same reporting period. All other reports and other documents must be certified upon submittal.

9.1 The Department may accept an electronic signature on an electronic application or other electronic record required by the Department if the person providing the electronic signature

a. uses a security procedure, as defined in AS 09.80.190, that the Department has approved; and

b. accepts or agrees to be bound by an electronic record executed or adopted with that signature.

10. Submittals. Unless otherwise directed by the Department or this permit, the Permittee shall submit to the Department one certified copy of reports, compliance certifications, and/or other submittals required by this permit. The Permittee may submit the documents electronically or by hard copy

10.1 Submit the certified copy of reports, compliance certifications, and/or other submittals in accordance with the submission instructions on the Department's Standard Permit Conditions web page at http://dec.alaska.gov/air/air-permit/standard-conditions/standard-condition-xvii-submission-instructions/.

11. Excess Emissions and Permit Deviation Reports. The Permittee shall report excess emissions and permit deviations as follows:

11.1 **Excess Emissions Reporting.** The Permittee shall report all emissions or operations that exceed emissions standards or limits of this permit as follows:

a. In accordance with 18 AAC 50.240(c), as soon as possible after the event commenced or is discovered, report

(i) excess emissions that present a potential threat to human health or safety; and

(ii) excess emissions that the Permittee believes to be unavoidable.

b. In accordance with 18 AAC 50.235(a), within two working days after the event commenced or was discovered, report an unavoidable emergency, malfunction, or nonroutine repair that causes emissions in excess of a technology-based emissions standard.

c. If a continuous or recurring excess emissions is not corrected within 48 hours of discovery, report within 72 hours of discovery unless the Department provides written permission to report under Condition 11.1d.

d. Report all other excess emissions not described in Conditions 11.1a, 11.1b, and 11.1c within 30 days after the end of the month during which the excess emissions occurred or as part of the next routine operating report in Condition 12 for excess emissions that occurred during the period covered by the report, whichever is sooner.

e. If requested by the Department, the Permittee shall provide a more detailed written report to follow up on an excess emissions report.

11.2 **Permit Deviations Reporting.** For permit deviations that are not "excess emissions," as defined under 18 AAC 50.990:

a. Report all other permit deviations within 30 days after the end of the month during which the deviation occurred or as part of the next routine operating report in Condition 12 for permit deviations that occurred during the period covered by the report, whichever is sooner.

11.3 **Reporting Instructions.** When reporting either excess emissions or permit deviations, the Permittee shall report using the Department's online form for all such submittals, beginning no later than September 7, 2023. The form can be found at the Division of Air Quality's Air Online Services (AOS) system webpage http://dec.alaska.gov/applications/air/airtoolsweb using the Permittee Portal option. Alternatively, upon written Department approval, the Permittee may submit the form contained in Section 8 of this permit. The Permittee must provide all information called for by the form that is used. Submit the report in accordance with the submission instructions on the Department's Standard Permit Conditions webpage found at http://dec.alaska.gov/air/air-permit/standard-conditions/standard-conditions-iii-and-iv-submission-instructions/.

12. Operating Reports. During the life of this permit[3], the Permittee shall submit to the Department an operating report in accordance with Conditions 9 and 10 by August 1 for the period January 1 to June 30 of the current year and by February 1 for the period July 1 to December 31 of the previous year.

12.1 The operating report must include all information required to be in operating reports by other conditions of this permit, for the period covered by the report.

12.2 When excess emissions or permit deviations that occurred during the reporting period are not included with the operating report under Condition 12.1, the Permittee shall identify

a. the date of the excess emissions or permit deviation;

[3] *Life of this permit* is defined as the permit effective dates, including any periods of reporting obligations that extend beyond the permit effective dates. For example, if a permit expires prior to the end of a calendar year, there is still a reporting obligation to provide operating reports for the periods when the permit was in effect.

b. the equipment involved;

c. the permit condition affected;

d. a description of the excess emissions or permit deviation; and

e. any corrective action or preventive measures taken and the date(s) of such actions; or

12.3 when excess emissions or permit deviation reports have already been reported under Condition 11 during the period covered by the operating report, the Permittee shall either

a. include a copy of those excess emissions or permit deviation reports with the operating report; or

b. cite the date(s) of those reports.

13. Annual Compliance Certification. Each year by March 31, the Permittee shall compile and submit to the Department an annual compliance certification report according to Condition 10.

13.1 Certify the compliance status of the stationary source over the preceding calendar year consistent with the monitoring required by this permit, as follows:

a. identify each term or condition set forth in Section 2 through Section 6, that is the basis of the certification;

b. briefly describe each method used to determine the compliance status;

c. state whether compliance is intermittent or continuous; and

d. identify each deviation and take it into account in the compliance certification.

13.2 In addition, submit a copy of the report directly to the Clean Air Act Compliance Manager, US EPA Region 10, ATTN: Air Toxics and Enforcement Section, Mail Stop: 20-C04, 1200 Sixth Avenue, Suite 155, Seattle, WA 98101-3188.

Section 6 General Source Test Requirements

20. Requested Source Tests. In addition to any source testing explicitly required by this permit, the Permittee shall conduct source testing as requested by the Department to determine compliance with applicable permit requirements.

21. Operating Conditions. Unless otherwise specified by an applicable requirement or test method, the Permittee shall conduct source testing

21.1 at a point or points that characterize the actual discharge into the ambient air; and

21.2 at the maximum rated burning or operating capacity of the emissions unit or another rate determined by the Department to characterize the actual discharge into the ambient air.

22. Reference Test Methods. The Permittee shall use the following references for test methods when conducting source testing for compliance with this permit:

22.1 Source testing for the reduction in visibility through the exhaust effluent must be conducted in accordance with the procedures set out in 40 C.F.R. 60, Appendix A, Reference Method 9. The Permittee may use the form in Attachment 1 of this permit to record data.

22.2 Source testing for emissions of total particulate matter, sulfur compounds, nitrogen compounds, carbon monoxide, lead, volatile organic compounds, fluorides, sulfuric acid mist, municipal waste combustor organics, metals and acid gases must be conducted in accordance with the methods and procedures specified in 40 C.F.R. 60, Appendix A.

22.3 Source testing for emissions of PM_{10} and $PM_{2.5}$ must be conducted in accordance with the procedures specified in 40 C.F.R. 51, Appendix M, Methods 201 or 201A and 202.

22.4 Source testing for emissions of any contaminant may be determined using an alternative method approved by the Department in accordance with 40 C.F.R. 63 Appendix A, Method 301.

23. Excess Air Requirements. To determine compliance with this permit, standard exhaust gas volumes must include only the volume of gases formed from the theoretical combustion of the fuel, plus the excess air volume normal for the specific emissions unit type, corrected to standard conditions (dry gas at 68° F and an absolute pressure of 760 millimeters of mercury).

24. Test Deadline Extension. The Permittee may request an extension to a source test deadline established by the Department. The Permittee may delay a source test beyond the original deadline only if the extension is approved in writing by the Department's appropriate division director or designee.

25. Test Plans. Before conducting any source tests, the Permittee shall submit a plan to the Department. The plan must include the methods and procedures to be used for sampling, testing, and quality assurance and must specify how the emissions unit will operate during the test and how the Permittee will document that operation. The Permittee shall submit a complete plan within 60 days after receiving a request under Condition 20 and at least 30 days before the scheduled date of any test unless the Department agrees in writing to some other time period. Retesting may be done without resubmitting the plan.

26. **Test Notification.** At least 10 days before conducting a source test, the Permittee shall give the Department written notice of the date and time the source test will begin.

27. **Test Reports.** Within 60 days after completing a source test, the Permittee shall submit one certified copy of the results in the format set out in the *Source Test Report Outline*, adopted by reference in 18 AAC 50.030. The Permittee shall certify the results in the manner set out in Condition 9. If requested in writing by the Department, the Permittee must provide preliminary results in a shorter period of time specified by the Department.

GVEA Zehnder BACT Cover Page

Contents

The following spreadsheets are included as part of the appendix. However, due to their electronic nature, they may be found posted separately on the web page:

1. Updated Department Zehnder Power Plant SO_2 Controls Economic Analysis.xlsx
2. A04_FuelPrices_1810.xlsx

ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION
Air Permits Program

BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION ADDENDUM
for
Golden Valley Electric Association
Zehnder Facility

Prepared by: Dave Jones
Reviewed by: Moses Coss
Final Date: October 21, 2024

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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

The Zehnder Facility (Zehnder) is an electric generating facility that combusts distillate fuel in combustion turbines to provide power to the Golden Valley Electric Association (GVEA) grid. The power plant contains two fuel oil-fired simple cycle gas combustion turbines and two diesel-fired generators (electro-motive diesels) used for emergency power and to serve as black start engines for the GVEA generation system. The primary fuel is stored in two 50,000 gallon aboveground storage tanks. Turbine startup fuel and electro-motive diesels primary fuel is stored in a 12,000 gallon above ground storage tank.

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

The initial BACT Determination for Zehnder was included in Part 4 of Appendix III.D.7.07 Control Strategies Chapter, in the State Air Quality Control Plan adopted on November 19, 2019, with amendments adopted on November 18, 2020, as part of a complete SIP package.[2] The *EPA's Air Plan Partial Approval and Partial Disapproval; AK, Fairbanks North Star Borough; 2006 24-hour $PM_{2.5}$ Serious Area and 189(d) Plan*[3] published in the Federal Register on December 5, 2023 (*88 Fed. Reg. 84658*) disapproved of Alaska's initial BACT determinations for $PM_{2.5}$ and SO_2 controls.

This BACT addendum addresses the EPA's disapproval of the significant emissions units (EUs) listed in the Zehnder Facility's operating permit AQ0109TVP04 Rev. 1. The BACT addendum also accounts for EPA's comments listed in Memorandum dated August 24, 2022 from Zach Hedgpeth, LSASD to Matthew Jentgen, ARD.[4] This BACT addendum provides the Department's review of the BACT analysis for $PM_{2.5}$, and the BACT analysis for sulfur dioxide (SO_2) emissions, which is a precursor pollutant that can form $PM_{2.5}$ in the atmosphere post combustion.

Since preparing the SIP amendments adopted on November 18, 2020, the Department conducted extensive modeling and found that SO_2 emissions from stationary sources do not significantly

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

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

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

[4] Document 000007_EPA Technical Support Document – GVEA BACT TSD v20220824: https://www.regulations.gov/document/EPA-R10-OAR-2022-0115-0214.

contribute to ground level $PM_{2.5}$ concentrations, and that SO_2 BACT emission limits are therefore not required for major stationary sources in the Fairbanks North Star Borough. SO_2 BACT determinations have, however, been included in this BACT Determination Addendum because the SO_2 major source precursor demonstration has not yet been approved by EPA.

Note that the section for oxides of nitrogen (NOx), which is also a precursor pollutant that can form $PM_{2.5}$ in the atmosphere post combustion, has been removed from this addendum because the EPA has approved[3] of the Department's comprehensive NOx precursor demonstration under 40 C.F.R. 51.1006(a)(1) and 51.1010(a)(2)(ii).

The following sections review GVEA's BACT analysis for the Zehnder Facility for technical accuracy and adherence to accepted engineering cost estimation practices.

2. BACT EVALUATION

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

Table A: Emission Units Subject to BACT Review

EU ID	Description of EU	Rating/Size	Installation or Construction Date
1	Fuel Oil-Fired Regenerative Simple Cycle Gas Turbine	268 MMBtu/hr (18.4 MW)	1971
2	Fuel Oil-Fired Regenerative Simple Cycle Gas Turbine	268 MMBtu/hr (18.4 MW)	1972
3	Diesel-Fired Emergency Generator Engine	28 MMBtu/hr (2.75 MW)	1970
4	Diesel-Fired Emergency Generator Engine	28 MMBtu/hr (2.75 MW)	1970
10	Diesel-Fired Boiler	1.7 MMBtu/hr	2012
11	Diesel-Fired Boiler	1.7 MMBtu/hr	2012

Five-Step BACT Determinations

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

Step 1 Identify All Potentially Available Control Technologies

The Department identifies all available control options 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. It is usually the first stop for BACT research. In addition to the RBLC search, the Department used several search engines to look for emerging and tried technologies used to control $PM_{2.5}$ and SO_2 emissions from equipment similar to those listed in Table A.

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

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

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

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

3. BACT DETERMINATION FOR NO_X

As discussed in the Section 1 Introduction, this BACT addendum has removed the previous NOx BACT determinations included in the State Air Quality Control Plan adopted on November 19, 2019, with amendments adopted on November 18, 2020,[2] because the optional comprehensive precursor demonstration (as allowed under 40 C.F.R. 51.1006(1) and 51.1010(a)(2)(ii)) for the precursor gas NOx for point sources illustrates that NOx controls are not needed. The Department submitted with the Serious SIP a final comprehensive precursor demonstration as justification not to require post emission controls for NOx. Please see the precursor demonstration for NOx in the Serious SIP Modeling Chapter III.D.7.8.[2] The $PM_{2.5}$ NAAQS Final SIP Requirements Rule states if the state determines through a precursor demonstration that controls for a precursor gas are not needed for attaining the standard, then the controls identified as BACT/BACM or Most Stringent Measure for the precursor gas are not required to be implemented.[5] The Department's NOx precursor demonstration was approved in *EPA's Air Plan Partial Approval and Partial Disapproval; AK, Fairbanks North Star Borough; 2006 24-hour $PM_{2.5}$ Serious Area and 189(d) Plan*[3] published in the Federal Register on December 5, 2023 (*88 Fed. Reg. 84658*).

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 Fuel Oil-Fired Simple Cycle Gas Turbines (EUs 1 and 2)

Possible $PM_{2.5}$ emission control technologies for the fuel oil-fired simple cycle gas turbines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 15.190, Simple Cycle Gas Turbines (> 25 MW) The search results for simple cycle gas turbines are summarized in Table 4-1.

Table 4-1. RBLC Summary of $PM_{2.5}$ Control for Simple Cycle Gas Turbines

Control Technology	Number of Determinations	Emission Limits
Good Combustion Practices	25	0.0038 – 0.0076 lb/MMBtu
Clean Fuels	12	5 – 14 lb/hr

RBLC Review

A review of similar units in the RBLC indicates restrictions on fuel sulfur contents and good combustion practices are the principal PM control technologies installed on simple cycle gas turbines. The lowest $PM_{2.5}$ emission rate listed in the RBLC is 0.0038 lb/MMBtu.

Step 1 - Identification of $PM_{2.5}$ Control Technology for the Simple Cycle Gas Turbines

From research, the Department identified the following technologies as available for control of $PM_{2.5}$ emissions from fuel oil-fired simple cycle gas turbines:

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

(a) Low Sulfur Fuel
Low sulfur fuel has been known to reduce particulate matter emissions. $PM_{2.5}$ emission rates for low sulfur fuel are not available and therefore a BACT emissions rate cannot be set for low sulfur fuel. The Department does not consider low sulfur fuel a technically feasible control technology for the fuel oil-fired simple cycle gas turbines.

(b) Low Ash Fuel
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 combustion components. EUs 1 and 2 are fired exclusively on distillate fuel which is a form of refined fuel, and potential $PM_{2.5}$ emissions are based on emission factors for distillate fuel. The Department considers low ash fuel a technically feasible control technology for the fuel oil-fired simple cycle gas turbines.

(c) Limited Operation
Limiting the operation of emission units reduces the potential to emit for those units. Due to EUs 1 and 2 currently operating under limits, the Department considers limited operation as a feasible control technology for the fuel oil-fired simple cycle gas turbines.

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

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

Combustion efficiency is dependent on the gas residence time, the combustion temperature, and the amount of mixing in the combustion zone. GCPs are accomplished primarily through combustion chamber design as it relates to residence time, combustion temperature, air-to-fuel mixing, and excess oxygen levels. 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 fuel oil-fired simple cycle gas turbines.

Step 2 - Eliminate Technically Infeasible $PM_{2.5}$ Controls for the Simple Cycle Gas Turbines
As explained in Step 1 of Section 4.1, the Department does not consider low sulfur fuel as technically feasible technology to control $PM_{2.5}$ emissions from the fuel oil-fired simple cycle gas turbines.

Step 3 - Rank the Remaining $PM_{2.5}$ Control Technologies for the Simple Cycle Gas Turbines
The following control technologies have been identified and ranked by efficiency for the control of $PM_{2.5}$ emissions from the fuel oil-fired simple cycle gas turbines:

(d) Good Combustion Practices (Less than 40% Control)

(b) Low Ash Fuel (0% Control)
(c) Limited Operation (0% Control)

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

Step 4 - Evaluate the Most Effective Controls

GVEA BACT Proposal

GVEA proposes the following as BACT for $PM_{2.5}$ emissions from the fuel oil-fired simple cycle gas turbines:

(a) $PM_{2.5}$ emissions from EUs 1 and 2 shall not exceed 0.012 lb/MMBtu over a 4-hour averaging period; and

(b) Maintaining good combustion practices.

Step 5 - Selection of $PM_{2.5}$ BACT for the Simple Cycle Gas Turbines

The Department's finding is that BACT for $PM_{2.5}$ emissions from the fuel oil-fired simple cycle gas turbines is as follows:

(a) $PM_{2.5}$ emissions from EUs 1 and 2 shall be controlled by combusting only low ash fuel;

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

(c) $PM_{2.5}$ emissions from EUs 1 & 2 shall not exceed 0.012 lb/MMBtu[6] over a 3-hour averaging period.

Table 4-2 lists the proposed $PM_{2.5}$ BACT determination for this facility along with those for other fuel oil-fired simple cycle gas turbines located in the Serious $PM_{2.5}$ nonattainment area.

Table 4-2. Comparison of $PM_{2.5}$ BACT for Simple Cycle Gas Turbines at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
GVEA – North Pole	Two Fuel Oil-Fired Simple Cycle Gas Turbines	1,344 MMBtu/hr	0.012 lb/MMBtu[6] (3-hour averaging period)	Limited Operation Low Ash Fuel Good Combustion Practices
GVEA – Zehnder	Two Fuel Oil-Fired Simple Cycle Gas Turbines	536 MMBtu/hr	0.012 lb/MMBtu[6] (3-hour averaging period)	Low Ash Fuel Good Combustion Practices

4.2 $PM_{2.5}$ BACT for the Large Diesel Fired Engines

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 17.110-17.190, Large Internal Combustion Engines (>500 hp). The search results for large diesel-fired engines are summarized in Table 4-3.

[6] Table 3.1-2a of US EPA's AP-42 Emission Factors. https://www3.epa.gov/ttnchie1/ap42/ch03/final/c03s01.pdf

Table 4-3. 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 principal $PM_{2.5}$ 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 controls 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 is 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. DPF can reduce $PM_{2.5}$ emissions by 85%. 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 technically feasible control technology for the large diesel-fired engine.

(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
NSPS Subpart IIII applies to stationary compression ignition internal combustion engines that are manufactured or reconstructed after July 11, 2005. Due to EUs 3 and 4 not being subject to either 40 C.F.R. 60 Subpart IIII, and considering 40 C.F.R. 63 Subpart ZZZZ does not contain emission standards for particulate emissions, the Department does not consider federal emission standards a technically feasible control technology for the large diesel-fired engines.

(g) Limited Operation
Limiting the operation of emissions units reduces the potential to emit of those units. The Department considers limited operation as a feasible control technology for the large diesel-fired engines.

(h) Good Combustion Practices
The theory of GCPs was discussed in detail in the $PM_{2.5}$ BACT section for the fuel oil-fired simple cycle gas turbines 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 engines.

Step 2 - Eliminate Technically Infeasible $PM_{2.5}$ Control Technologies for the Large Engines
$PM_{2.5}$ emission rates for low sulfur fuel are not available and therefore a BACT emissions rate cannot be set for low sulfur fuel. Low sulfur fuel is not a technically feasible control technology.

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

GVEA BACT Proposal

GVEA proposes limited operation as BACT for $PM_{2.5}$ emissions from the large diesel-fired engines:

(a) Limit non-emergency operation of EUs 3 and 4 to no more than 500 hours per year each for maintenance checks and readiness testing; and

(b) $PM_{2.5}$ emissions from EUs 3 and 4 shall not exceed 0.1 lb/MMBtu[7] over a 4-hour averaging period.

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

The Department reviewed GVEA's proposal finds that $PM_{2.5}$ emissions from the large diesel-fired engines can also be controlled by good combustion practices.

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) Limit non-emergency operation of EUs 3 and 4 to no more than 100 hours per year each;

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

(c) $PM_{2.5}$ emissions from EUs 3 and 4 shall not exceed 0.32 g/hp-hr[7] over a 3-hour averaging period.

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

Facility	Process Description	Capacity	Limitation	Control Method
UAF	Large Diesel-Fired Engines	> 500 hp	0.05 - 0.32 g/hp-hr (3-hour avg)	Positive Crankcase Ventilation Limited Operation Ultra-Low Sulfur Diesel
Fort Wainwright	8 Large Diesel-Fired Engines	> 500 hp	0.15 – 0.32 g/hp-hr (3-hour avg)	Limited Operation Ultra-Low Sulfur Diesel Federal Emission Standards
GVEA North Pole	Large Diesel-Fired Engine	600 hp	0.32 g/hp-hr (3-hour avg)	Limited Operation Positive Crankcase Ventilation Good Combustion Practices
GVEA Zehnder	2 Large Diesel-Fired Engines	11,000 hp (each)	0.32 g/hp-hr (3-hour avg)	Limited Operation Good Combustion Practices

4.3 $PM_{2.5}$ BACT for the Diesel Fired Boilers

Possible $PM_{2.5}$ emission control technologies for small diesel-fired boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 13.220, Commercial/Institutional Size Boilers (<100 MMBtu/hr). The search results for diesel-fired boilers are summarized in Table 4-5.

[7] Table 3.4-1 of US EPA's AP-42 Emission Factors (PM). https://www3.epa.gov/ttn/chief/ap42/ch03/final/c03s04.pdf

Table 4-5. 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 that good combustion practices is the principal $PM_{2.5}$ control technology determined for small 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) 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%.[8] 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 diesel-fired boilers.

(b) Good Combustion Practices
The theory of GCPs was discussed in detail in the $PM_{2.5}$ BACT section for the fuel oil-fired simple cycle gas turbines 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 the 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) Wet Scrubbers (50% - 99% Control)
(b) Good Combustion Practices (Less than 40% Control)

[8] 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

Step 4 - Evaluate the Most Effective Controls

GVEA BACT Proposal

GVEA proposes the following as BACT for $PM_{2.5}$ emissions from the diesel-fired boilers:

(a) Good Combustion Practices; and

(b) $PM_{2.5}$ emissions shall not exceed 2.13 lb/1,000 gallons[9] over a 4-hour averaging period.

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

The Department reviewed GVEA's proposal and finds that the two diesel-fired boilers have a combined PTE of less than two tpy for $PM_{2.5}$ based on continuous operation of 8,760 hours per year. At two 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 0.016 lb/MMBtu[10] over a 3-hour averaging period; and

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

Table 4-6 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 4-6. Comparison of $PM_{2.5}$ BACT for the Diesel-Fired Boilers at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
UAF	6 Small Diesel-Fired Boilers	< 100 MMBtu/hr	0.016 lb/MMbtu[10] (3-hr avg)	Limited Operation & Good Combustion Practices
Fort Wainwright	4 Small Diesel-Fired Boilers	< 100 MMBtu/hr	0.016 lb/MMbtu[10] (3-hr avg)	Good Combustion Practices
GVEA Zehnder	2 Small Diesel-Fired Boilers	1.7 MMBtu/hr (each)	0.016 lb/MMbtu[10] (3-hr avg)	Good Combustion Practices

[9] Tables 1.3-2 & 1.3-7 of US EPA's AP-42 Emission Factors: https://www3.epa.gov/ttn/chief/ap42/ch01/final/c01s03.pdf

[10] Emissions factor from AP-42 Table's 1.3-2 (total condensable particulate matter from No. 2 oil, 1.3 lb/1,000 gal) and 1.3-7 ($PM_{2.5}$ size-specific factor from distillate oil, 0.83 lb/1,000 gal) converted to lb/MMBtu. Note that the E.F. has been corrected from the previous SIP because the small boilers are considered "commercial" under Table 1.3-7 and not "industrial" under Table 1.3-6.

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 Fuel Oil-Fired Simple Cycle Gas Turbines

Possible SO_2 emission control technologies for the large dual fuel fired boiler was obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 15.190, Liquid Fuel-Fired Simple Cycle Gas Turbines (> 25 MW). The search results for simple cycle gas turbines are summarized in Table 5-1.

Table 5-1. RBLC Summary of SO_2 Controls for Fuel Oil-Fired Simple Cycle Gas Turbines

Control Technology	Number of Determinations	Emission Limits	
Ultra-Low Sulfur Diesel	7	0.0015	% S by wt.
Low Sulfur Fuel	2	0.0026 – 0.055	lb/MMBtu
Good Combustion Practices	3	0.6	lb/hr

RBLC Review

A review of similar units in the RBLC indicates that limiting the sulfur content of fuel and good combustion practices are the principal SO_2 control technologies determined as BACT for fuel oil-fired simple cycle gas turbines. The lowest SO_2 emission rate listed in the RBLC is combustion of ULSD at 0.0015 % S by wt.

Step 1 - Identification of SO_2 Control Technology for the Simple Cycle Gas Turbines

From research, the Department identified the following technologies as available for control of SO_2 emissions from fuel oil-fired simple cycle gas turbines:

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

(b) Low Sulfur Fuel (No. 1 Fuel Oil)
No. 1 Fuel Oil has a fuel sulfur content of approximately 0.1 percent sulfur by weight. Using No. 1 fuel oil would reduce SO_2 emissions because the fuel oil-fired simple cycle gas turbines are combusting standard No. 2 fuel oil that has a sulfur content of up to 0.5 percent sulfur by weight. Switching to No. 1 fuel oil could reach an 80 percent decrease in SO_2 emissions from the fuel oil-fired simple cycle gas turbines during non-startup operation. The Department considers No. 1 fuel oil a technically feasible control technology for the fuel oil-fired simple cycle gas turbines.

(c) Good Combustion Practices (GCPs)
The theory of GCPs was discussed in detail in the $PM_{2.5}$ BACT section for the fuel oil-fired simple cycle gas turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of SO_2. The Department considers GCPs a technically feasible control technology for the fuel oil-fired simple cycle gas turbines.

Step 2 - Eliminate Technically Infeasible SO_2 Controls for the Simple Cycle Gas Turbines
All control technologies identified are technically feasible for the fuel oil-fired simple cycle gas turbines.

Step 3 - Rank Remaining SO_2 Control Technologies for the Simple Cycle Gas Turbines
The following control technologies have been identified and ranked for control of SO_2 emissions from the fuel oil-fired simple cycle turbines:

(a) Ultra Low Sulfur Diesel (99.7% Control)
(b) Low Sulfur Fuel (No. 1 Fuel Oil) (80% Control)
(c) Good Combustion Practices (Less than 40% Control)

Step 4 - Evaluate the Most Effective Controls

GVEA BACT Proposal

GVEA provided an economic analysis for switching the fuel combusted in the simple cycle gas turbines to ultra-low sulfur diesel (ULSD). A summary of the analysis for both of the turbines combined is shown below:

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

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
ULSD (0.0015 % S wt.)	580	578	$8,674,362	$8,239,935	$14,250
Capital Recovery Factor = 0.0944 (7% interest rate for a 20 year equipment life)					

GVEA contends that the economic analysis indicates the level of SO_2 reduction does not justify the fuel switch to ULSD in the simple cycle turbines based on the excessive cost per ton of SO_2 removed per year.

GVEA proposes the following as BACT for SO_2 emissions from the simple cycle gas turbines:

(a) SO_2 emissions from the operation of the fuel oil-fired simple cycle gas turbines will be controlled with good combustion practices; and

(b) Fuel burned in the fuel oil-fired simple cycle gas turbine will be limited to a sulfur content of 0.5 percent by weight.

Department Evaluation of BACT for SO_2 Emissions from the Simple Cycle Gas Turbines
The Department revised the cost analysis provided for the fuel switch to ULSD in the simple cycle gas turbines by changing the interest rate to 8.5% (current bank prime interest rate) and updated the equipment life to 30 years. The Department left the existing 580 ton per year SO_2

emission limit for the facility and the average fuel cost increase provided by GVEA for the Zehnder Facility of $0.251/gallon unchanged from the previous BACT cost calculation conducted on November 13, 2019. Additionally, the Department reviewed the cost information provided by GVEA to appropriately evaluate the total capital investment of installing two new 1.5-million-gallon ULSD storage tanks at GVEA's North Pole Facility. The capital investment for EUs 1 and 2 at the Zehnder Facility equates to 28.5% of the total capital investment for the new tanks.

A summary of these analyses for both of the turbines combined is shown in Table 5-3:

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

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
ULSD	580	578	$8,674,362	$5,109,893	$8,387
Capital Recovery Factor = 0.0931 (8.5% interest rate for a 30-year equipment life)					

The Department's economic analysis indicates the level of SO_2 reduction justifies the use of ULSD as BACT for the fuel oil-fired simple cycle gas turbines located in the Serious PM-2.5 nonattainment area.

Step 5 - Selection of SO_2 BACT for the Simple Cycle Gas Turbines

The Department's finding is that BACT for SO_2 emissions from the fuel oil-fired simple cycle gas turbines is as follows:

(a) SO_2 emissions from EUs 1 and 2 shall be controlled by limiting the sulfur content of fuel combusted in the turbines to no more than 0.0015 percent by weight (15 ppmw, ULSD); and

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

Table 5-4 lists the proposed SO_2 BACT determination for this facility along with those for other fuel oil-fired simple cycle gas turbines located in the Serious $PM_{2.5}$ nonattainment area.

Table 5-4. Comparison of SO_2 BACT for Simple Cycle Gas Turbines at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
GVEA – North Pole	Two Fuel Oil-Fired Simple Cycle Gas Turbines	1,344 MMBtu/hr	0.0015 % S wt.	Good Combustion Practices ULSD
GVEA – Zehnder	Two Fuel Oil-Fired Simple Cycle Gas Turbines	536 MMBtu/hr	0.0015 % S wt.	Good Combustion Practices ULSD

5.2 SO_2 BACT for the Large Diesel-Fired Engines

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 5-5.

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

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

RBLC Review
A review of similar units in the RBLC indicates combustion of low sulfur fuel, limited operation, good combustion practices, and compliance with the federal emission standards are the principal 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 fuel oil-fired simple cycle gas turbines 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
NSPS Subpart IIII applies to stationary compression ignition internal combustion engines that are manufactured or reconstructed after July 11, 2005. Due to EUs 3 and 4 not being subject to either 40 C.F.R. 60 Subpart IIII and considering 40 C.F.R. 63 Subpart ZZZZ does not contain emission standards for particulate emissions, the Department does not consider federal emission standards a technically feasible control technology for the large diesel-fired engines.

(c) 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 large diesel-fired engines.

(d) Good Combustion Practices
The theory of GCPs was discussed in detail in the $PM_{2.5}$ BACT section for the fuel oil-fired simple cycle gas turbines 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

GVEA BACT Proposal

GVEA provided an economic analysis of the control technologies available for the large diesel-fired engine to demonstrate that the use of ULSD with limited operation is not economically feasible on these units. A summary of the analysis for EUs 3 and 4 is shown below:

Table 5-6. GVEA Economic Analysis for Technically Feasible SO_2 Controls per Engine

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
ULSD	3.71	3.70	--	$28,732	$7,768
Capital Recovery Factor = 0.1424 (7% interest rate for a 10 year equipment life)					

GVEA contends that the economic analysis indicates the level of SO_2 reduction does not justify the use of ULSD for the large diesel-fired engines based on the excessive cost per ton of SO_2 removed per year.

GVEA proposes the following as BACT for SO_2 emissions from the diesel-fired engines:

(a) SO_2 emissions from the operation of the diesel fired engines will be controlled with good combustion practices; and

(b) Limit the sulfur content of fuel combusted in EUs 3 and 4 to no more than 0.5 percent sulfur by weight.

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

The Department reviewed GVEA's proposal for EUs 3 and 4 and finds that ULSD is an economically feasible control technology for large diesel-fired engines located in the Serious $PM_{2.5}$ nonattainment area. The Department does not agree with some of the assumptions provided in GVEA's cost analysis that cause an overestimation of the cost effectiveness. However, since this overestimation is still cost effective, the Department did not revise the cost analysis. The Department further 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 the BACT for SO_2 emissions from the diesel-fired engines is as follows:

(a) SO_2 emissions from EUs 3 and 4 shall be controlled limiting the sulfur content of fuel combusted in the engines to no more than 0.0015 percent by weight;

(b) Limit non-emergency operation of EUs 3 and 4 to no more than 100 hours per year each; and

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

Table 5-7 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 5-7. 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	Limited Operation Good Combustion Practices 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

5.3 SO_2 BACT for the Diesel Fired Boilers

Possible SO_2 emission control technologies for small diesel-fired boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 13.220, Industrial Size Boilers (<100 MMBtu/hr). The search results for diesel-fired engines are summarized in Table 5-8.

Table 5-8. RBLC Summary of SO_2 Control for the Small 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 principal 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 SO_2 control for the diesel-fired boilers:

(a) Ultra Low Sulfur Diesel
ULSD has a fuel sulfur content of 0.0015 percent sulfur by weight or less. Using ULSD would reduce SO_2 emissions because the mid-sized diesel 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 decrease in SO_2 emissions from the diesel fired boilers. The Department considers ULSD a technically feasible control technology for the diesel-fired boilers.

(b) Good Combustion Practices
The theory of GCPs was discussed in detail in the $PM_{2.5}$ BACT section for the fuel oil-fired simple cycle gas turbine 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) Good Combustion Practices (Less than 40% Control)

Step 4 - Evaluate the Most Effective Controls

GVEA BACT Proposal

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

(a) Combust only ULSD.

Department Evaluation of BACT for SO_2 Emissions from Diesel-Fired Boilers
The Department reviewed GVEA's proposal and finds that SO_2 emissions from the diesel-fired boilers can additionally be controlled with good combustion practices.

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 EUs 10 and 11 shall be controlled limiting the sulfur content of fuel combusted in the turbines to no more than 0.0015 percent by weight; and

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

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

Facility	Process Description	Capacity	Limitation	Control Method
Fort Wainwright	4 Diesel-Fired Boilers	< 100 MMBtu/hr	15 ppmw S in fuel	Limited Operation Good Combustion Practices Ultra-Low Sulfur Diesel
UAF	6 Diesel-Fired Boilers	< 100 MMBtu/hr	15 ppmw S in fuel	Good Combustion Practices Ultra-Low Sulfur Diesel
GVEA Zehnder	2 Diesel-Fired Boilers	< 100 MMBtu/hr	15 ppmw S in fuel	Good Combustion Practices Ultra-Low Sulfur Diesel

6. BACT DETERMINATION SUMMARY

Table 6-1. Proposed NOx BACT Limits

EU ID	Description of EU	Capacity	Proposed BACT Limit	Proposed BACT Control
All	N/A	N/A	EPA approved a comprehensive precursor demonstration for NOx See details in the Section 1 Introduction	

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

EU ID	Description of EU	Capacity	Proposed BACT Limit	Proposed BACT Control
1	Fuel Oil-Fired Regenerative Gas Simple Cycle Gas Turbine	268 MMBtu/hr	0.012 lb/MMBtu	Low Ash Fuel Good Combustion Practices
2	Fuel Oil-Fired Regenerative Gas Simple Cycle Gas Turbine	268 MMBtu/hr	0.012 lb/MMBtu	
3	Diesel-Fired Emergency Generator Engine	28 MMBtu/hr	0.32 g/hp-hr	Good Combustion Practices Limited Operation (100 hours/year each, for non-emergency operation)
4	Diesel-Fired Emergency Generator Engine	28 MMBtu/hr	0.32 g/hp-hr	
10	Diesel-Fired Boiler	1.7 MMBtu/hr	0.016 lb/MMBtu	Good Combustion Practices
11	Diesel-Fired Boiler	1.7 MMBtu/hr	0.016 lb/MMBtu	

(*) 3-hour average

Table 6-3. Proposed SO_2 BACT Limits

EU ID	Description of EU	Capacity	Proposed BACT Limit	Proposed BACT Control
1	Fuel Oil-Fired Regenerative Gas Simple Cycle Gas Turbine	268 MMBtu/hr	15 ppmw S in Fuel	Ultra Low Sulfur Diesel Good Combustion Practices
2	Fuel Oil-Fired Regenerative Gas Simple Cycle Gas Turbine	268 MMBtu/hr	15 ppmw S in Fuel	
3	Diesel-Fired Emergency Generator Engine	28 MMBtu/hr	15 ppmw S in Fuel	Ultra Low Sulfur Diesel Good Combustion Practices Limited Operation (100 hours/year each, for non-emergency operation)
4	Diesel-Fired Emergency Generator Engine	28 MMBtu/hr	15 ppmw S in Fuel	
10	Diesel-Fired Boiler	1.7 MMBtu/hr	15 ppmw S in Fuel	Ultra Low Sulfur Diesel Good Combustion Practices
11	Diesel-Fired Boiler	1.7 MMBtu/hr	15 ppmw S in Fuel	

Stationary Source: Zehnder Facility

Emission Units: EU IDs 1 and 2 (268 MMBtu/hr (18.4 MW) Simple Cycle Turbines)

Pollutant of Concern: SO_2	
BACT Measure	**Monitoring, Recordkeeping and Reporting Requirements** Error! Bookmark not defined.
Combust Only Ultra Low Sulfur fuel at no more than 0.0015 percent sulfur by weight	• For each shipment of fuel, test the sulfur content or keep receipts that specify fuel grade date, and quantity of fuel received. Keep records of the results of sulfur content tests and receipts for fuel shipments. • Include in each semi-annual operating report required by the Operating Permit, a summary of fuel test results or fuel grade shipping receipts from the reporting period.
Good Combustion Practices	• Perform regular maintenance according to the manufacturer's and the operator's maintenance requirements and procedures. • Keep records of maintenance conducted on emission units . • Keep a copy of the manufacturer's and the operator's recommended maintenance procedures. • Report a summary of the maintenance records. • Operate the EUs consistent with manufacturer's recommended combustion settings or those established during the source test conducted to demonstrate compliance with the BACT emissions limit.

Emission Units: EU IDs 3 and 4 (28.5 MMBtu/hr (2.75 MW) Emergency Diesel Engines)

Pollutant of Concern: SO_2	
BACT Measure	**Monitoring, Recordkeeping and Reporting Requirements** Error! Bookmark not defined.
Combust Only Ultra Low Sulfur fuel at no more than 0.0015 percent sulfur by weight	• For each shipment of fuel, test the sulfur content or keep receipts that specify fuel grade date, and quantity of fuel received. Keep records of the results of sulfur content tests and receipts for fuel shipments. • Include in each semi-annual operating report required by the Operating Permit, a summary of fuel test results or fuel grade shipping receipts from the reporting period.
Limited Operation (100 hours of maintenance checks, readiness testing, and non-emergency operation per year)	• Maintain and operate a non-resettable hour meter on each engine, capable of recording the total hours of operation. • By the end of each calendar month, record the total operating hours of each EU for the previous calendar month and for the previous 12 consecutive months. • Report the operating hour records for each engine.
Good Combustion Practices	• Perform regular maintenance according to the manufacturer's and the operator's maintenance requirements and procedures. • Keep records of any maintenance that would have a significant effect on emissions. The records may be kept in electronic format.

	• Keep a copy of the manufacturer's and the operator's maintenance procedures. • Report a summary of the maintenance records.

Emission Unit: EU IDs 10 and 11 (1.7 MMBtu/hr Boilers)

Pollutant of Concern: SO_2	
BACT Measure	**Monitoring, Recordkeeping and Reporting Requirements** Error! Bookmark not defined.
Combust Only Ultra Low Sulfur fuel at no more than 0.0015 percent sulfur by weight	• For each shipment of fuel, test the sulfur content or keep receipts that specify fuel grade date, and quantity of fuel received. Keep records of the results of sulfur content tests and receipts for fuel shipments. • Include in each semi-annual operating report required by the Operating Permit, a summary of fuel test results or fuel grade shipping receipts from the reporting period.
Good Combustion Practices	• Perform regular maintenance according to the manufacturer's and the operator's maintenance requirements and procedures. • Keep records of any maintenance that would have a significant effect on emissions. The records may be kept in electronic format. • Keep a copy of the manufacturer's and the operator's maintenance procedures. • Report a summary of the maintenance records.

DEPARTMENT OF ENVIRONMENTAL CONSERVATION

AIR QUALITY CONTROL MINOR PERMIT

Minor Permit: AQ0109MSS01 Revision 2 **Final Date – October 28, 2024**
Rescinds Permit: AQ0109MSS01 Revision 1

The Alaska Department of Environmental Conservation (Department), under the authority of AS 46.14 and 18 AAC 50, issues Air Quality Control Minor Permit AQ0109MSS01 Revision 2 to the Permittee listed below.

Permittee:	**Golden Valley Electric Association (GVEA)** P.O. Box 71249, Fairbanks, AK 99707-1249
Stationary Source:	**Zehnder Facility**
Location:	758 Illinois Street, Fairbanks, AK 99707 64º 51´ 15" North; 147º 43´ 30" West
Project:	Serious $PM_{2.5}$ State Implementation Plan (SIP)
Permit Contact:	Naomi Morton Knight, P.E Phone No.: (907) 458-4557 email: NMKnight@gvea.com

The Permittee submitted an application for Minor Permit AQ0109MSS01 under 18 AAC 50.508(5) for an Owner Requested Limit (ORL) to avoid classification as a major source of SO_2 in a nonattainment area under 40 C.F.R. 51.165 and 18 AAC 50.311. With the issuance of AQ0109MSS01 Revision 1, the Department reclassified the basis for the permit issuance to AS 46.14.130(c)(2), because the previous ORLs have been removed and the Department found that public health or air quality effects provide a reasonable basis to regulate the stationary source. This finding is contained in the State Air Quality Control Plan adopted on November 19, 2019.

AQ0109MSS01 Revision 2 is issued to address comments from the US EPA concerning State Implementation Plan requirements for $PM_{2.5}$ limits and associated monitoring recordkeeping and reporting for EU IDs 1, 2, 3, 4, 10 and 11 of GVEA's Zehnder Facility.

This permit satisfies the obligation of the Permittee to obtain a minor permit under 18 AAC 50. As required by AS 46.14.120(c), the Permittee shall comply with the terms and conditions of this permit.

James R. Plosay, Manager
Air Permits Program

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Table of Contents

Abbreviations and Acronyms

AAAQS .... Alaska Ambient Air Quality Standards
AAC .... Alaska Administrative Code
ADEC .... Alaska Department of Environmental Conservation
AOS .... Air Online Services
AS .... Alaska Statutes
ASTM .... American Society for Testing and Materials
BACM .... Best Available Control Measures
BACT .... best available control technology
CDX .... Central Data Exchange
CEDRI .... Compliance and Emissions Data Reporting Interface
C.F.R. .... Code of Federal Regulations
CAA .... Clean Air Act
CO .... carbon monoxide
Department .... Alaska Department of Environmental Conservation
dscf .... dry standard cubic foot
EPA .... US Environmental Protection Agency
EU .... emissions unit
gr/dscf .... grain per dry standard cubic foot (1 pound = 7000 grains)
gph .... gallons per hour
HAPs .... hazardous air pollutants [as defined in AS 46.14.990]
hp .... horsepower
ID .... emissions unit identification number
kPa .... kiloPascals
kWe .... Kilowatt-electric
lb/kW-hr .... pounds per kilowatt-hour.
LAER .... lowest achievable emission rate
MACT .... maximum achievable control technology [as defined in 40 C.F.R. 63]
MMBtu/hr .... million British thermal units per hour
MMscf .... million standard cubic feet
MR&R .... monitoring, recordkeeping, and reporting
NAA .... Nonattainment Area
NESHAPs .... National Emission Standards for Hazardous Air Pollutants [as contained in 40 C.F.R. 61 and 63]
NO_x .... nitrogen oxides
NRE .... nonroad engine
NSPS .... New Source Performance Standards [as contained in 40 C.F.R. 60]
O & M .... operation and maintenance
O_2 .... oxygen
PAL .... plantwide applicability limitation
PM_{10} .... particulate matter less than or equal to a nominal 10 microns in diameter
$PM_{2.5}$ .... particulate matter less than or equal to a nominal 2.5 microns in diameter
ppm .... parts per million
ppmv, ppmvd .... parts per million by volume on a dry basis
psia .... pounds per square inch (absolute)
PSD .... prevention of significant deterioration
PTE .... potential to emit
SIC .... Standard Industrial Classification
SIP .... State Implementation Plan
SPC .... Standard Permit Condition or Standard Operating Permit Condition
SO_2 .... sulfur dioxide
The Act .... Clean Air Act
TPH .... tons per hour
TPY .... tons per year
VOC .... volatile organic compound [as defined in 40 C.F.R. 51.100(s)]
VOL .... volatile organic liquid [as defined in 40 C.F.R. 60.111b, Subpart Kb]
vol% .... volume percent
wt% .... weight percent
wt%S_{fuel} .... weight percent of sulfur in fuel

Section 1 Emissions Unit Inventory

Emissions Unit (EU) Authorization. The Permittee is authorized to operate the EUs listed in Table 1 in accordance with the terms and conditions of this permit. The information in Table 1 is for identification purposes only, unless otherwise noted in the permit. The specific EU descriptions do not restrict the Permittee from replacing an EU identified in Table 1.

Table 1 – EU Inventory

EU ID	EU Description	Make/Model	Rating/Max Capacity	Fuel	Installation Date
1	General Electric Frame 5 MS 5001-M	Fuel Oil-Fired Model MS Simple Cycle Combustion Gas Turbine	268 MMBtu/hr (18.4 MW)	Diesel	1971
2	General Electric Frame 5 MS 5001-M	Fuel Oil-Fired Model MS Simple Cycle Combustion Gas Turbine	268 MMBtu/hr (18.4 MW)	Diesel	1972
3	General Motors Electro-Motive Diesel (EMD)	Fuel Oil-Fired Emergency Diesel Generator Model No. 20-645E4	28 MMBtu/hr (2.75 MW)	Diesel	1970
4	General Motors Electro-Motive Diesel (EMD)	Fuel Oil-Fired Emergency Diesel Generator Model No. 20-645E4	28 MMBtu/hr (2.75 MW)	Diesel	1970
10	Boiler	Vehicle Shop Boiler 1 – Weil-McLain Model H-688	1.7 MMBtu/hr	Heating Oil/ Diesel	2012
11	Boiler	Vehicle Shop Boiler 2 – Weil-McLain Model H-688	1.7 MMBtu/hr	Heating Oil/ Diesel	2012

1. The Permittee shall comply with all applicable provisions of AS 46.14 and 18 AAC 50 when installing a replacement EU, including any applicable minor or construction permit requirements**.**

Section 3 State Implementation Plan (SIP) Requirements

Fairbanks $PM_{2.5}$ Serious Nonattainment Area SIP Requirements

5. **Simple Cycle Turbine Emissions Limit.** The Permittee shall limit the emissions from the simple cycle turbine EU IDs 1 and 2 as specified in Table 2.

Table 2 - EU IDs 1 and 2 SIP BACT Limits

Pollutant	BACT Control	Fuel Type	BACT Emissions Limit
$PM_{2.5}$	Good Combustion Practices	Low Ash (Distillate) Fuel	0.012 lb/MMBtu (3-hour average)

5.1 For EU IDs 1 and 2, the Permittee shall:

a. Conduct an initial source test on EU IDs 1 and/or 2 in accordance with Section 6, within 12-months of permit issuance, to demonstrate compliance with the $PM_{2.5}$ emissions limit listed in Table 2.

(i) Conduct the source test for at least three loads representative of the normal operating range of the EU. The Permittee may perform testing at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice.

(ii) Emission results shall be reported as the arithmetic 3-hour average of all valid test runs and shall be in units of lb/MMBtu.

(iii) The Permittee shall report the results of the source test in accordance with Condition 26.

(iv) Include the following in the next operating report in accordance with Condition 11, that is due after the submittal date of the source test report:

(A) a summary of the source test results; and

(B) relevant combustion settings (including but not limited to average CO and O_2 concentrations in the flue gas) established during the source test that demonstrates compliance with the BACT $PM_{2.5}$ emissions limit in Table 2.

b. Report the compliance status with the $PM_{2.5}$ emissions limit listed in Table 2 in accordance with each annual compliance certification described in Condition 12.

c. Combust only low ash (distillate) fuel.

(i) For each shipment of fuel, keep receipts that specify the fuel grade and amount.

(ii) Include copies of the records required by Condition 5.1c(i) for the reporting period, in each operating report required by Condition 11.

d. Maintain good combustion practices at all times the EUs are in operation.

(i) Perform regular maintenance according to the manufacturer's and the operator's maintenance requirements and procedures.

(ii) Keep records of any maintenance that would have a significant effect on emissions. The records may be kept in electronic format.

(iii) Keep a copy of the manufacturer's and the operator's maintenance procedures.

(iv) Report in accordance with Condition 11, a summary of the maintenance records collected under Condition 5.1d(ii).

(v) Operate the EUs consistent with manufacturer's recommended combustion settings (e.g., maximum CO, excess air in flue gas, and other relevant parameters) or those established during the source test conducted to demonstrate compliance with the BACT emissions limit in Table 2.

(A) For each of EU IDs 1 and 2, measure and record the CO and O_2 concentrations in the exhaust stream using a portable handheld combustion analyzer during or within 30 days after the end of a calendar quarter that the EU operates.[1]

(B) Include copies of the records required by Condition 5.1d(v)(A) for the reporting period, in each operating report required by Condition 11.

e. Report in accordance with Condition 10, whenever

(i) an emissions rate determined by the source test required by Condition 5.1a exceeds the limit in Table 2; or

(ii) any of Conditions 5.1a through 5.1d are not met.

6. **Emergency Diesel Engine Generators Emissions Limit.** The Permittee shall limit the emissions from the emergency diesel engine generators EU IDs 3 and 4 as specified in Table 3.

[1] It is not the Department's intention to require the Permittee to start up an EU just to perform the CO and O_2 concentration measurements.

Table 3 - EU IDs 3 and 4 SIP BACT Limits

Pollutant	BACT Control	Fuel Type	BACT Emissions Limit
$PM_{2.5}$	Limited Operation and Good Combustion Practices	Diesel	0.32 g/hp-hr (3-hour average)

6.1 For EU IDs 3 and 4, the Permittee shall demonstrate compliance with the $PM_{2.5}$ BACT emissions limit contained in Table 3 as follows:

a. Maintain good combustion practices at all times the EUs are in operation.

(i) Perform regular maintenance according to the manufacturer's and the operator's maintenance requirements and procedures.

(ii) Keep records of any maintenance that would have a significant effect on emissions. The records may be kept in electronic format.

(iii) Keep a copy of the manufacturer's and the operator's maintenance procedures.

b. Limit the maintenance checks, readiness testing, and non-emergency operation of each EU to 100 hours per calendar year.

(i) For EU IDs 3 and 4, monitor, record, and report as follows:

(A) Maintain and operate a non-resettable hour meter on each engine, capable of recording the total hours of operation.

(B) By the end of each calendar month, record the total operating hours of each EU

(1) for the previous calendar month; and

(2) for the previous 12 consecutive months, as calculated using the records obtained under Condition 6.1b(i)(B)(1).

c. Report in accordance with Condition 11

(i) a summary of the maintenance records collected under Condition 6.1a(ii); and

(ii) the operating hour records for each engine collected under Condition 6.1b(i)(B)(2).

d. Report the compliance status with the $PM_{2.5}$ emissions limit listed in Table 3 in accordance with each annual compliance certification described in Condition 12.

e. Report in accordance with Condition 10, whenever

(i) an emissions rate exceeds the limit in Table 3; or

(ii) any of Conditions 6.1a through 6.1d are not met.

7. **Diesel-Fired Boilers Emissions Limit.** The Permittee shall limit the emissions from the diesel-fired boilers, EU IDs 10 and 11, as specified in Table 4.

Table 4 - EU IDs 10 and 11 SIP BACT Limits

Pollutant	BACT Control	Fuel Type	BACT Emissions Limit
$PM_{2.5}$	Good Combustion Practices	Diesel	0.016 lb/MMBtu (3-hour average)

7.1 For EU IDs 10 and 11, the Permittee shall demonstrate compliance with the $PM_{2.5}$ BACT emissions limit contained in Table 4 as follows:

a. Maintain good combustion practices at all times the EUs are in operation.

(i) Perform regular maintenance according to the manufacturer's and the operator's maintenance requirements and procedures.

(ii) Keep records of any maintenance that would have a significant effect on emissions. The records may be kept in electronic format.

(iii) Keep a copy of the manufacturer's and the operator's maintenance procedures.

b. Report under Condition 11, a summary of the maintenance records collected under Condition 7.1a(ii).

c. Report the compliance status with the $PM_{2.5}$ emissions limit listed in Table 4 in accordance with each annual compliance certification described in Condition 12.

d. Report in accordance with Condition 10, whenever

(i) an emissions rate exceeds the limit in Table 4; or

(ii) any of Conditions 7.1a through 7.1c are not met.

Section 4 Recordkeeping, Reporting, and Certification Requirements

8. **Certification.** The Permittee shall certify any permit application, report, affirmation, or compliance certification submitted to the Department and required under the permit by including the signature of a responsible official for the permitted stationary source following the statement: "*Based on information and belief formed after reasonable inquiry, I certify that the statements and information in and attached to this document are true, accurate, and complete.*" Excess emissions reports must be certified either upon submittal or with an operating report required for the same reporting period. All other reports and other documents must be certified upon submittal.

8.1 The Department may accept an electronic signature on an electronic application or other electronic record required by the Department if the person providing the electronic signature

a. uses a security procedure, as defined in AS 09.80.190, that the Department has approved; and

b. accepts or agrees to be bound by an electronic record executed or adopted with that signature.

9. **Submittals.** Unless otherwise directed by the Department or this permit, the Permittee shall submit to the Department one certified copy of reports, compliance certifications, and/or other submittals required by this permit. The Permittee may submit the documents electronically or by hard copy.

9.1 Submit the certified copy of reports, compliance certifications, and/or other submittals in accordance with the submission instructions on the Department's Standard Permit Conditions web page athttp://dec.alaska.gov/air/air-permit/standard-conditions/standard-condition-xvii-submission-instructions/.

10. **Excess Emissions and Permit Deviation Reports.** The Permittee shall report excess emissions and permit deviations as follows:

10.1 **Excess Emissions Reporting.** The Permittee shall report all emissions or operations that exceed emissions standards or limits of this permit as follows:

a. In accordance with 18 AAC 50.240(c), as soon as possible after the event commenced or is discovered, report

(i) excess emissions that present a potential threat to human health or safety; and

(ii) excess emissions that the Permittee believes to be unavoidable.

b. In accordance with 18 AAC 50.235(a), within two working days after the event commenced or was discovered, report an unavoidable emergency, malfunction, or nonroutine repair that causes emissions in excess of a technology-based emissions standard.

c. If a continuous or recurring excess emissions is not corrected within 48 hours of discovery, report within 72 hours of discovery unless the Department provides written permission to report under Condition 10.1d.

d. Report all other excess emissions not described in Conditions 10.1a, 10.1b, and 10.1c within 30 days after the end of the month during which the excess emissions occurred or as part of the next routine operating report in Condition 11 for excess emissions that occurred during the period covered by the report, whichever is sooner.

e. If requested by the Department, the Permittee shall provide a more detailed written report to follow up on an excess emissions report.

10.2 **Permit Deviations Reporting.** For permit deviations that are not "excess emissions," as defined under 18 AAC 50.990:

a. Report all other permit deviations within 30 days after the end of the month during which the deviation occurred or as part of the next routine operating report in Condition 11 for permit deviations that occurred during the period covered by the report, whichever is sooner.

10.3 **Reporting Instructions.** When reporting either excess emissions or permit deviations, the Permittee shall report using the Department's online form for all such submittals, beginning no later than September 7, 2023. The form can be found at the Division of Air Quality's Air Online Services (AOS) system webpage http://dec.alaska.gov/applications/air/airtoolsweb using the Permittee Portal option. Alternatively, upon written Department approval, the Permittee may submit the form contained in Section 8 of this permit. The Permittee must provide all information called for by the form that is used. Submit the report in accordance with the submission instructions on the Department's Standard Permit Conditions webpage found at http://dec.alaska.gov/air/air-permit/standard-conditions/standard-conditions-iii-and-iv-submission-instructions/.

11. Operating Reports. During the life of this permit[2], the Permittee shall submit to the Department an operating report in accordance with Conditions 8 and 9 by August 1 for the period January 1 to June 30 of the current year and by February 1 for the period July 1 to December 31 of the previous year.

11.1 The operating report must include all information required to be in operating reports by other conditions of this permit, for the period covered by the report.

11.2 When excess emissions or permit deviations that occurred during the reporting period are not included with the operating report under Condition 11.1, the Permittee shall identify

a. the date of the excess emissions or permit deviation;

[2] *Life of this permit* is defined as the permit effective dates, including any periods of reporting obligations that extend beyond the permit effective dates. For example, if a permit expires prior to the end of a calendar year, there is still a reporting obligation to provide operating reports for the periods when the permit was in effect.

b. the equipment involved;

c. the permit condition affected;

d. a description of the excess emissions or permit deviation; and

e. any corrective action or preventive measures taken and the date(s) of such actions; or

11.3 when excess emissions or permit deviation reports have already been reported under Condition 10 during the period covered by the operating report, the Permittee shall either

a. include a copy of those excess emissions or permit deviation reports with the operating report; or

b. cite the date(s) of those reports.

12. Annual Compliance Certification. Each year by March 31, the Permittee shall compile and submit to the Department an annual compliance certification report according to Condition 9.

12.1 Certify the compliance status of the stationary source over the preceding calendar year consistent with the monitoring required by this permit, as follows:

a. identify each term or condition set forth in Section 2 through Section 6, that is the basis of the certification;

b. briefly describe each method used to determine the compliance status;

c. state whether compliance is intermittent or continuous; and

d. identify each deviation and take it into account in the compliance certification.

12.2 In addition, submit a copy of the report directly to the Clean Air Act Compliance Manager, US EPA Region 10, ATTN: Air Toxics and Enforcement Section, Mail Stop: 20-C04, 1200 Sixth Avenue, Suite 155, Seattle, WA 98101-3188.

Section 6 General Source Test Requirements

19. Requested Source Tests. In addition to any source testing explicitly required by this permit, the Permittee shall conduct source testing as requested by the Department to determine compliance with applicable permit requirements.

20. Operating Conditions. Unless otherwise specified by an applicable requirement or test method, the Permittee shall conduct source testing

20.1 at a point or points that characterize the actual discharge into the ambient air; and

20.2 at the maximum rated burning or operating capacity of the emissions unit or another rate determined by the Department to characterize the actual discharge into the ambient air.

21. Reference Test Methods. The Permittee shall use the following references for test methods when conducting source testing for compliance with this permit:

21.1 Source testing for the reduction in visibility through the exhaust effluent must be conducted in accordance with the procedures set out in 40 C.F.R. 60, Appendix A, Reference Method 9. The Permittee may use the form in Attachment 1 of this permit to record data.

21.2 Source testing for emissions of total particulate matter, sulfur compounds, nitrogen compounds, carbon monoxide, lead, volatile organic compounds, fluorides, sulfuric acid mist, municipal waste combustor organics, metals and acid gases must be conducted in accordance with the methods and procedures specified in 40 C.F.R. 60, Appendix A.

21.3 Source testing for emissions of PM_{10} and $PM_{2.5}$ must be conducted in accordance with the procedures specified in 40 C.F.R. 51, Appendix M, Methods 201 or 201A and 202.

21.4 Source testing for emissions of any contaminant may be determined using an alternative method approved by the Department in accordance with 40 C.F.R. 63 Appendix A, Method 301.

22. Excess Air Requirements. To determine compliance with this permit, standard exhaust gas volumes must include only the volume of gases formed from the theoretical combustion of the fuel, plus the excess air volume normal for the specific emissions unit type, corrected to standard conditions (dry gas at 68° F and an absolute pressure of 760 millimeters of mercury).

23. Test Deadline Extension. The Permittee may request an extension to a source test deadline established by the Department. The Permittee may delay a source test beyond the original deadline only if the extension is approved in writing by the Department's appropriate division director or designee.

24. Test Plans. Before conducting any source tests, the Permittee shall submit a plan to the Department. The plan must include the methods and procedures to be used for sampling, testing, and quality assurance and must specify how the emissions unit will operate during the test and how the Permittee will document that operation. The Permittee shall submit a complete plan within 60 days after receiving a request under Condition 19 and at least 30 days before the scheduled date of any test unless the Department agrees in writing to some other time period. Retesting may be done without resubmitting the plan.

25. **Test Notification.** At least 10 days before conducting a source test, the Permittee shall give the Department written notice of the date and time the source test will begin.

26. **Test Reports.** Within 60 days after completing a source test, the Permittee shall submit one certified copy of the results in the format set out in the *Source Test Report Outline*, adopted by reference in 18 AAC 50.030. The Permittee shall certify the results in the manner set out in Condition 8. If requested in writing by the Department, the Permittee must provide preliminary results in a shorter period of time specified by the Department.

UAF BACT Cover Page

Contents

The following spreadsheets are included as part of the appendix. However, due to their electronic nature, they may be found posted separately on the web page:

1. Department BACT AppxG Andritz CDS-CostEst.xlsx
2. BACT AppxH BACT DSI CostEst _Jan2023.xlsx
3. Department BACT AppxH BACT TriMer_DSI-CostEst_Jan2023.xlsx
4. Departments UAF_BACT AppxF EPA WFG CCM Est.xlsx
5. Updated Department Version of UAF BACT PM2.5 Tables 4-X.xlsx
6. UAF BACT AppxF EPA WFGD CCM Estimate Jan2023.xlsx
7. UAF BACT AppxG Andritz CDS CostEst Jan2023.xlsx
8. UAF BACT APPxH BACT DSI-CostEst Jan2023.xlsx
9. UAF BACT AppxH TriMer DSI-costEst Jan2023.xlsx
10. UAF BACT Report Tables Jan2023.xlsx
11. Costs Assoc W Stack Replacement or CDS Jan2023.xlsx

ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION
Air Permits Program

BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION ADDENDUM
for
University of Alaska
University of Alaska Fairbanks Campus

Prepared by: Dave Jones
Reviewed by: Moses Coss
Final Date: October 21, 2024

https://stateofalaska.sharepoint.com/sites/DEC/AIR/np/serioussip/Shared Documents/Revised-Amended Serious SIP/2024 Revised-Amended Serious SIP Section Templates/Adopted Versions/Appendices/BACT/UAF/10.21.24 Final UAF BACT Determination.docx

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

The University of Alaska Fairbanks (UAF) Campus stationary source has two oil-fired boilers (converted to dual fuel-fired by Minor Permit No. AQ0316MSS02), installed in 1970 and 1987. The power plant also has a 13,266 hp backup diesel generator installed in 1998. The UAF Campus also includes 13 diesel-fired boilers installed between 1985 and 2005, three emergency diesel engines installed between 1998 and 2019, one classroom engine installed in 1987, and one permitted diesel engine installed in 2013. Additional permitted EUs installed in 2016 at the UAF Campus include limestone, sand, and ash handling systems, a circulating fluidized bed with limestone injection (FBLI) dual fuel-fired boiler, and a coal handling system.

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

The initial BACT Determination for UAF was included in Part 3 of Appendix III.D.7.07 Control Strategies Chapter, in the State Air Quality Control Plan adopted on November 19, 2019, with amendments adopted on November 18, 2020, as part of a complete SIP package.[2] The *EPA's Air Plan Partial Approval and Partial Disapproval; AK, Fairbanks North Star Borough; 2006 24-hour $PM_{2.5}$ Serious Area and 189(d) Plan*[3] published in the Federal Register on December 5, 2023 (*88 Fed. Reg. 84657*) disapproved of Alaska's initial BACT determinations for $PM_{2.5}$ and SO_2 controls.

Since preparing the SIP amendments adopted on November 18, 2020, the Department conducted extensive modeling and found that SO_2 emissions from stationary sources do not significantly contribute to ground level $PM_{2.5}$ concentrations, and that SO_2 BACT emission limits are therefore not required for major stationary sources in the Fairbanks North Star Borough. SO_2 BACT determinations have, however, been included in this BACT Determination Addendum because the SO_2 major source precursor demonstration has not yet been approved by EPA.

This BACT addendum addresses the significant EUs listed in Title V Operating Permit AQ0316TVP03 and Minor Permit AQ0316MSS08. The BACT addendum also accounts for EPA's

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

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

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

comments listed in Memorandum dated August 24, 2022 from Zach Hedgpeth, R10/LSASD/ECB and Larry Sorrels OAQPS/HEID/AEG to Matthew Jentgen, ARD.[4] This BACT Addendum provides the Department's review of the BACT analysis for $PM_{2.5}$, and the BACT analysis for sulfur dioxide (SO_2) emissions, which is a precursor pollutant that can form $PM_{2.5}$ in the atmosphere post combustion.

Note that the section for oxides of nitrogen (NOx), which is also a precursor pollutant that can form $PM_{2.5}$ in the atmosphere post combustion, has been removed from this addendum because the EPA has approved[3] of the Department's comprehensive NOx precursor demonstration under 40 C.F.R. 51.1006(a)(1) and 51.1010(a)(2)(ii).

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

2. BACT EVALUATION

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

Table A: Emission Units Subject to BACT Review

EU ID[1]	Description of EU	Rating / Size		Fuel Type	Installation or Construction Date
3	Dual-Fired Boiler	180.9	MMBtu/hr	Diesel	1970
4	Dual-Fired Boiler	180.9	MMBtu/hr	Dual Fuel	1987
8	Peaking/Backup Diesel Generator	13,266	hp	Diesel	1999
9A	Medical/Pathological Waste Incinerator	83	lb/hr	Medical / Infectious Waste	2006
17	Diesel Boiler	4.93	MMBtu/hr	Diesel	2003
18	Diesel Boiler	4.93	MMBtu/hr	Diesel	2003
19	Diesel Boiler	6.13	MMBtu/hr	Diesel	2004
20	Diesel Boiler	6.13	MMBtu/hr	Diesel	2004
21	Diesel Boiler	6.13	MMBtu/hr	Diesel	2004
22	Diesel Boiler	8.5	MMBtu/hr	Diesel	2005
24	Diesel Generator Engine	72	hp	Diesel	2001
~~26~~	~~Diesel Generator Engine~~	~~64~~	~~hp~~	~~Diesel~~	~~1987~~
27	Diesel Generator Engine	500	hp	Diesel	2013
29	Diesel Generator Engine	314	hp	Diesel	2013

[4] Document 000008_EPA Technical Support Document – UAF BACT TSD v20220824: **https://www.regulations.gov/document/EPA-R10-OAR-2022-0115-0215**.

EU ID[1]	Description of EU	Rating / Size		Fuel Type	Installation or Construction Date
34	Diesel Generator Engine	324	hp	Diesel	2015
35	Diesel Generator Engine	1,220	hp	Diesel	2019
105	Limestone Handling System	1,200	acfm	N/A	2019
107	Sand Handling System	1,600	acfm	N/A	2019
109	Ash Handling System	1,000	acfm	N/A	2019
110	Ash Handling System Vacuum	2,000	acfm	N/A	2019
111	Ash Loadout to Truck	N/A		N/A	2019
113	Dual Fuel-Fired Circulating Fluidized Bed (CFB) Boiler	295.6	MMBtu/hr	Coal/Woody Biomass	2019
114	Dry Sorbent Handling Vent Filter Exhaust	5	acfm	N/A	2019
128	Coal Silo No. 1 with Bin Vent	1,650	acfm	N/A	2019
129	Coal Silo No. 2 with Bin Vent	1,650	acfm	N/A	2019
130	Coal Silo No. 3 with Bin Vent	1,650	acfm	N/A	2019

Table Notes:
[1] Since the previous BACT analysis for UAF was adopted on November 19, 2019, amendments adopted November 19, 2020, EUs 23, 26, and 28 have been permanently removed from the stationary source and EUs 34 and 35 have been added.

Five-Step BACT Determinations

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

Step 1 Identify All Potentially Available Control Technologies

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

Step 2 Eliminate Technically Infeasible Control Technologies:

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

Step 3 Rank the Remaining Control Technologies by Control Effectiveness

The Department ranks the remaining control technologies in order of control effectiveness with the most effective at the top.

Step 4 Evaluate the Most Effective Controls and Document the Results as Necessary

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

Step 5 Select BACT

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

3. BACT DETERMINATION FOR NO_X

As discussed in the Section 1 Introduction, this BACT addendum has removed the previous NOx BACT determinations included in the State Air Quality Control Plan adopted on November 19, 2019, with amendments adopted on November 18, 2020,[2] because the optional comprehensive precursor demonstration (as allowed under 40 C.F.R. 51.1006(1) and 51.1010(a)(2)(ii)) for the precursor gas NOx for point sources illustrates that NOx controls are not needed. The Department submitted with the Serious SIP a final comprehensive precursor demonstration as justification not to require post emission controls for NOx. Please see the precursor demonstration for NOx in the Serious SIP Modeling Chapter III.D.7.8. [2] The $PM_{2.5}$ NAAQS Final SIP Requirements Rule states if the state determines through a precursor demonstration that controls for a precursor gas are not needed for attaining the standard, then the controls identified as BACT/BACM or Most Stringent Measure for the precursor gas are not required to be implemented.[5] The Department's NOx precursor demonstration was approved in *EPA's Air Plan Partial Approval and Partial Disapproval; AK, Fairbanks North Star Borough; 2006 24-hour $PM_{2.5}$ Serious Area and 189(d) Plan*[3] published in the Federal Register on December 5, 2023 (*88 Fed. Reg. 84657*).

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

4. BACT DETERMINATION FOR $PM_{2.5}$

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

4.1 $PM_{2.5}$ BACT for the Large Dual Fuel-Fired Boiler (EU 113)

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

Table 4-1. RBLC Summary of $PM_{2.5}$ Control for Industrial Coal-Fired Boilers

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

RBLC Review

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

Step 1 - Identification of $PM_{2.5}$ Control Technologies for the Large Dual Fuel-Fired Boiler

From research, the Department identified the following technologies as available for control of $PM_{2.5}$ emissions from the large dual fuel-fired boiler:

(a) Fabric Filters

Fabric filters or baghouses are comprised of an array of filter bags contained in housing. Air passes through the filter media from the “dirty” to the “clean” side of the bag. These devices undergo periodic bag cleaning based on the build-up of filtered material on the bag as measured by pressure drop across the device. The cleaning cycle is set to allow operation within a range of design pressure drop. Fabric filters are characterized by the type of cleaning cycle: mechanical-shaker,[6] pulse-jet,[7] and reverse-air.[8] Fabric filter systems have control efficiencies of 95% to 99.9%, and are generally specified to meet a discharge concentration of filterable particulate (e.g., 0.01 grains per dry standard cubic feet). The Department considers fabric filters a technically feasible control technology for the large dual fuel-fired boiler.

(b) Wet and Dry Electrostatic Precipitators (ESP)

ESPs remove particles from a gas stream by electrically charging particles with a discharge electrode in the gas path and then collecting the charged particles on grounded plates. The

[6] https://www3.epa.gov/ttn/catc/dir1/ff-shaker.pdf
[7] https://www3.epa.gov/ttn/catc/dir1/ff-pulse.pdf
[8] https://www3.epa.gov/ttn/catc/dir1/ff-revar.pdf

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 periodic deluge of water is what cleans the collection plate surface. Wet ESPs typically control streams with inlet grain loading values of 0.5 – 5 gr/ft^3 and have control efficiencies between 90% and 99.9%.[9] Wet ESPs have the advantage of controlling some amount of condensable particulate matter. The collection plates in a dry ESP are periodically cleaned by a rapper or hammer that sends a shock wave that knocks the collected particulate off the plate. Dry ESPs typically control streams with inlet grain loading values of 0.5 – 5 gr/ft^3 and have control efficiencies between 99% and 99.9%.[10] The Department considers ESP a technically feasible control technology for the large dual fuel-fired boiler.

(c) Wet Scrubbers
Wet scrubbers use a scrubbing solution to remove PM/PM_{10}/$PM_{2.5}$ from exhaust gas streams. The mechanism for particulate collection is impaction and interception by water droplets. Wet scrubbers are configured as counter-flow, cross-flow, or concurrent flow, but typically employ counter-flow where the scrubbing fluid is in the opposite direction as the gas flow. Wet scrubbers have control efficiencies of 50% - 99%.[11] One advantage of wet scrubbers is that they can be effective on condensable particulate matter. A disadvantage of wet scrubbers is that they consume water and produce water and sludge. For fine particulate control, a venturi scrubber can be used, but typical loadings for such a scrubber are 0.1-50 grains/scf. The Department considers the use of wet scrubbers to be a technically feasible control technology for the large dual fuel-fired boiler.

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

[9] **https://www3.epa.gov/ttn/catc/dir1/fwespwpi.pdf**
https://www3.epa.gov/ttn/catc/dir1/fwespwpl.pdf
[10] **https://www3.epa.gov/ttn/catc/dir1/fdespwpi.pdf**
https://www3.epa.gov/ttn/catc/dir1/fdespwpl.pdf
[11] **https://www3.epa.gov/ttn/catc/dir1/fcondnse.pdf**
https://www3.epa.gov/ttn/catc/dir1/fiberbed.pdf
https://www3.epa.gov/ttn/catc/dir1/fventuri.pdf

(e) Settling Chamber

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

(f) Good Combustion Practices (GCPs)

GCPs typically include the following elements:

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

Combustion efficiency is dependent on the gas residence time, the combustion temperature, and the amount of mixing in the combustion zone. GCPs are accomplished primarily through combustion chamber design as it relates to residence time, combustion temperature, air-to-fuel mixing, and excess oxygen levels. Proper management of the combustion process will result in a reduction of $PM_{2.5}$ emissions. The Department considers GCPs a technically feasible control technology for the large dual fuel-fired boiler.

Step 2 - Elimination of Technically Infeasible $PM_{2.5}$ Control Technologies for the Large Dual Fuel-Fired Boiler

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

Step 3 - Rank the Remaining $PM_{2.5}$ Control Technologies for the Large Dual Fired Boiler

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

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

Step 4 - Evaluate the Most Effective Controls

UAF BACT Proposal

UAF proposes the following as BACT for $PM_{2.5}$ emissions from the large dual fuel-fired boiler:

(a) $PM_{2.5}$ emissions shall be controlled by installing, operating, and maintaining a fabric filter; and

(b) $PM_{2.5}$ emissions shall not exceed 0.012 lb/MMBtu.

Step 5 - Selection of $PM_{2.5}$ BACT for the Large Dual Fuel-Fired Boiler

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

(a) $PM_{2.5}$ emissions from EU 113 shall be controlled by operating and maintaining fabric filters at all times of operation;

(b) $PM_{2.5}$ emissions from EU 113 shall be controlled by maintaining good combustion practices at all times the units are in operation;

(c) $PM_{2.5}$ emissions from EU 113 shall not exceed 0.012 lb/MMBtu[12] averaged over a three-hour period;

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

(e) Maintain compliance with State opacity standards listed under 50.055(a)(1).

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

Table 4-2. Comparison of $PM_{2.5}$ BACT for Coal-Fired Boilers at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
UAF	One Dual Fuel-Fired Boiler	295.6 MMBtu/hr	0.012 lb/MMBtu[12]	Fabric Filters; Good Combustion Practices
Fort Wainwright	Six Coal-Fired Boilers	1,380 MMBtu/hr	0.045 lb/MMBtu[13]	Full Steam Baghouse; Good Combustion Practices
Chena	4 Coal-Fired Boilers	497 MMBtu/hr (combined)	0.045 lb/MMBtu[13]	Full Stream Baghouse; Good Combustion Practices

4.2 $PM_{2.5}$ BACT for the Mid-Sized Diesel-Fired Boilers (EUs 3 and 4)

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

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

[13] The 0.045 lb/MMBtu emission rate is calculated using EPA AP-42 Tables 1.1-50.04 lb/MMBtu for spreader stoker boilers with a baghouse) and 1.1-6 (0.01A lb/ton for $PM_{2.5}$ sized particles for a boiler with a baghouse converted to lb/MMBtu using the typical gross as received heat value of 7,560 Btu/lb and an ash content (A) of 7 percent). Heat and ash content of the Usibelli coal is identified in the coal data sheet at: http://usibelli.com/coal/data-sheet.

Table 4-3. RBLC Summary of $PM_{2.5}$ Control for Mid-Sized Boilers Firing Diesel

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

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

Table 4-4. RBLC Summary of $PM_{2.5}$ Control for Mid-Sized Boilers Firing Natural Gas

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

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

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

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

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

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

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

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

(f) Limited Operation
EU 4 currently operates under a combined annual NOx emission limit with EU 8. 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 mid-sized diesel-fired boilers.

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

Step 2 - Eliminate Technically Infeasible $PM_{2.5}$ Control Technologies for the Mid-Sized Diesel-Fired Boilers
As explained in Step 1 of Section 4.2, the Department does not consider natural gas as a technically feasible technology to control particulate matter emissions from the mid-sized diesel-fired boilers.

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

EU 3 is used as a backup to EU 113 if it fails. As the backup EU, it is not technically feasible to use an operational limit to control $PM_{2.5}$ emissions.

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

Step 4 - Evaluate the Most Effective Controls

UAF BACT Proposal

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

(a) $PM_{2.5}$ emissions from EU 3 and 4 shall not exceed 0.016 lb/MMBtu while firing diesel fuel;

(b) $PM_{2.5}$ emissions from EU 4 shall not exceed 7.6 lb/MMscf while firing natural gas; and

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

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

(a) $PM_{2.5}$ emissions from EUs 3 and 4 shall not exceed 0.012 lb/MMBtu[14] averaged over a 3-hour period while firing diesel fuel;

(b) $PM_{2.5}$ emissions from EU 4 shall not exceed 0.0075 lb/MMBtu[15] averaged over a 3-hour period while firing natural gas;

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

(d) Initial compliance with the proposed $PM_{2.5}$ emission limits will be demonstrated by conducting a performance test on EU IDs 3 or 4 on diesel fuel and EU ID 4 on natural gas; and

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

Table 4-5 lists the BACT determination for the facility along with those for other mid-sized boilers in the Serious $PM_{2.5}$ nonattainment area.

Table 4-5. Comparison of $PM_{2.5}$ BACT Limits for the Mid-Sized Diesel-Fired Boilers

Facility	EU ID	Process Description	Capacity	Fuel	Limitation	Control Method
UAF	3	Dual Fuel-Fired Boilers	100 – 250 MMBtu/hr	Diesel	0.012 lb/MMBtu[14]	Good Combustion Practices
	4			Diesel	0.012 lb/MMBtu[14]	Limited Operation Good Combustion Practices
				Natural Gas	0.0075 lb/MMBtu[15]	

4.3 $PM_{2.5}$ BACT for the Small Diesel-Fired Boilers (EUs 17 through 22)

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

Table 4-6. RBLC Summary of $PM_{2.5}$ Control for Small Diesel-Fired Boilers

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

[14] 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.

[15] Emission factor from AP-42 Table 1.4-2 for total particulate matter and converted to lb/MMBtu.

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 tons per year (tpy).

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

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

(b) Limited Operation
The theory behind limited operation was discussed in detail in the $PM_{2.5}$ BACT section for the mid-sized diesel-fired boilers and will not be repeated here. The Department considers limited operation a technically feasible control technology for the small diesel-fired boilers.

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

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

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

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

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

Step 4 - Evaluate the Most Effective Controls

UAF BACT Proposal

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

Table 4-7. UAF Economic Analysis for Technically Feasible $PM_{2.5}$ Controls

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

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

UAF proposes the following as BACT for $PM_{2.5}$ emissions for the small diesel-fired boilers:

(a) $PM_{2.5}$ emissions from the operation of the small diesel-fired boilers EUs 19 through 22 will be controlled by limiting the combined operation to no more than 18,739 hours per 12-month rolling period; and

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

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

The Department reviewed UAF's proposal and finds that the 6 small diesel-fired boilers have a combined potential to emit (PTE) of less than 2 tpy for $PM_{2.5}$ based on unrestricted operation of EUs 17 and 18 and a limit of 18,739 combined hours of operation per 12 month rolling period for EUs 19 through 22. The Department does not agree with all of the assumptions made by UAF in its cost analysis. However, the Department believes that at less than 2 tpy of $PM_{2.5}$ emissions spread across six boilers, the cost effectiveness in terms of dollars per ton for add-on pollution control for these units is economically infeasible.

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

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

(a) $PM_{2.5}$ emissions from the operation of the small diesel-fired boilers EUs 19 through 22 will be controlled by limiting the combined operation to no more than 18,739 hours per 12-month rolling period; [16]

(b) $PM_{2.5}$ emissions from EUs 17 through 22 shall not exceed 0.016 lb/MMBtu (3-hour average);[17] and

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

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

[16] Limit established in Minor Permit AQ0316MSS07 to avoid minor permitting under 18 AAC 50.502(c)(3)(A)(iii).

[17] Emission factor corrected from 2019 SIP: AP-42 Table's 1.3-2 (total condensable particulate matter from No. 2 oil, 1.3 lb/1,000 gal) and 1.3-7 ($PM_{2.5}$ size-specific factor from distillate oil, 0.83 lb/1,000 gal) converted to lb/MMBtu. Note that the E.F. has been corrected from the previous SIP because the small boilers are considered "commercial" under Table 1.3-7 and not "industrial" under Table 1.3-6.

Table 4-8. $PM_{2.5}$ BACT Limits for the Small Diesel-Fired Boilers

Facility	Process Description	Capacity	Limitation	Control Method
UAF	6 Diesel-Fired Boilers	< 100 MMBtu/hr	0.016 lb/MMBtu[14]	Limited Operation Good Combustion Practices
Fort Wainwright	4 Diesel-Fired Boilers	< 100 MMBtu/hr	0.016 lb/MMBtu[14]	Good Combustion Practices
Zehnder Facility	2 Diesel-Fired Boilers	< 100 MMBtu/hr	0.016 lb/MMBtu[14]	Good Combustion Practices

4.4 $PM_{2.5}$ BACT for the Large Diesel-Fired Engines (EUs 8 and 35)

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

Table 4-9. RBLC Summary of $PM_{2.5}$ Control for the Large Diesel-Fired Engines

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

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

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

(a) Diesel Particulate Filter (DPF)
DPF is a control technology that are designed to physically filter particulate matter from the exhaust stream. Several designs exist which require cleaning and replacement of the filter media after soot has become caked onto the filter media. Regenerative filter designs are also available that burn the soot on a regular basis to regenerate the filter media. The Department considers DPF a technically feasible control technology for the large diesel-fired engines.

(b) Positive Crankcase Ventilation
Positive crankcase ventilation is the process of re-introducing the combustion air into the cylinder chamber for a second chance at combustion after the air has seeped into and collected in the crankcase during the downward stroke of the piston cycle. This process allows any unburned fuel to be subject to a second combustion opportunity. Any combustion products act as a heat sink during the second pass through the piston, which will lower the temperature of combustion and reduce the thermal NOx formation. Positive crankcase ventilation is included in the design of EU 8. The Department considers positive crankcase ventilation a technically feasible control technology for the large diesel-fired 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. EU 8 is fired exclusively on distillate fuel which is a form of refined fuel. The potential $PM_{2.5}$ emissions are based on emission factors for distillate fuel. EU 8 is capable of firing either diesel or heavy fuel oil (non-low ash fuel) according to manufacturer specifications. The Department considers low ash diesel as a technically feasible control technology for the large diesel-fired engines.

(d) Federal Emission Standards
The NSPS 40 CFR 60 Subpart IIII applies to stationary compression ignition internal combustion engines that are manufactured or reconstructed after July 11, 2005. EU 8 was manufactured prior to July 11, 2005 and has not been reconstructed since. Therefore, EU 8 is not subject to NSPS Subpart IIII. EU 8 is considered an institutional emergency engine and is therefore exempt from NESHAP 40 CFR 63 Subpart ZZZZ. For these reasons federal emission standards will not be carried forward as a control technology for EU 8. EU 35 was installed in 2019 and is subject to the requirements of 40 C.F.R. 60 Subpart IIII, which is considered the baseline level of control for this emission unit.

(e) Limited Operation
EU 8 currently operates under a combined annual NOx emission limit with EU 4. Limiting the operation of emissions units reduces the potential to emit of those units. EU 35 is regulated under NSPS Subpart IIII requirements for emergency engines, which limits non-emergency operating hours. Therefore, the Department considers limited operation a technically feasible control technology for the large diesel-fired engines.

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

Step 2 - Eliminate Technically Infeasible $PM_{2.5}$ Control Technologies for the Large Engines
As explained in Step 1 of Section 4.4, the Department does not consider meeting the federal emission standards as a technically feasible technology to control $PM_{2.5}$ emissions from EU 8.

Additionally, EU 8 is equipped with SCR for controlling NOx emissions, which creates a backpressure. This backpressure does not allow for the operation of a DPF. Therefore, a DPF is not a technically feasible $PM_{2.5}$ control option for EU 8. The use of a DPF and federal emissions standards remains as effective control options for EU 35.

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:

(a)	Diesel Particulate Filter	(85 – 90% Control)
(f)	Good Combustion Practices	(Less than 40% Control)
(b)	Positive Crankcase Ventilation	(~10% Control)
(c)	Low Ash/Sulfur Diesel	(~20% Control)
(f)	Limited Operation	(0% Control)
(d)	Federal Emission Standards	(0% Control)

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

Step 4 - Evaluate the Most Effective Controls

UAF BACT Proposal

UAF proposes the following as BACT for $PM_{2.5}$ emissions from the large diesel-fired engine EU 8:[18]

(a) $PM_{2.5}$ emissions from EU 8 shall be controlled by operating with positive crankcase ventilation;

(b) $PM_{2.5}$ emissions from EU 8 shall not exceed 0.32 g/hp-hr (3-hour average);

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

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

Department Evaluation of BACT for $PM_{2.5}$ Emissions from the Large Diesel-Fired Engines:
Because EU 8 cannot operate with a DPF due to the unacceptable increase in backpressure that the DPF would cause, UAF has proposed the top level of $PM_{2.5}$ controls for the engine. However, for EU 35 a DPF is a technically feasible control option. EU 35 has potential $PM_{2.5}$ emissions of 0.03 tpy, which is an order of magnitude lower than the two other diesel engines EUs 26 and 27 that the Department found DPFs to be economically infeasible in Table's 4-13 and 4-14. Therefore, an economic analysis for implementing DPF on EU 35 would result in an even higher cost effectiveness value. The Department notes that EU 35 is limited to 100 hours per calendar year of non-emergency operation and required to combust ULSD under the existing federal NSPS Subpart IIII requirements.

[18] EU ID 35 was added to the stationary source after the initial submittal of BACT proposals by UAF.

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) $PM_{2.5}$ emissions from EUs 8 and 35 shall be controlled by operating positive crankcase ventilation, maintaining good combustion practices by following the manufacturer's operation and maintenance procedures, and combusting ULSD at all times the EUs are in operation;

(b) Limit non-emergency operation of EUs 8 and 35 to no more than 100 hours per year;

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

(d) $PM_{2.5}$ emissions from EU 8 shall not exceed 0.32 g/hp-hr[19] over a 3-hour period; and

(e) $PM_{2.5}$ emissions from EU 35 shall not exceed 0.05 g/hp-hr over a 3-hour period.

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

Table 4-10. Comparison of $PM_{2.5}$ BACT for the Large Diesel-Fired Engine at Nearby Power Plants

Facility	Process Description	Capacity	Limitation (*)	Control Method
UAF	Large Diesel-Fired Engines	> 500 hp	0.05 – 0.32 g/hp-hr	Positive Crankcase Ventilation Limited Operation Good Combustion Practices Ultra-Low Sulfur Diesel
Fort Wainwright	Large Diesel-Fired Engines	> 500 hp	0.15 – 0.32 g/hp-hr	Limited Operation Ultra-Low Sulfur Diesel Federal Emission Standards
GVEA North Pole	Large Diesel-Fired Engines	> 500 hp	0.32 g/hp-hr	Limited Operation Good Combustion Practices
GVEA Zehnder	Large Diesel-Fired Engines	> 500 hp	0.32 g/hp-hr	Limited Operation Good Combustion Practices

(*) (3-hour average)

4.5 $PM_{2.5}$ BACT for the Small Diesel-Fired Engines (EUs 24, 26, 27, 29, and 34)

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

[19] Emission factor from AP-42 Table 3.4-1 (0.0007 lb/hp-hr) converted to g/hp-hr

Table 4-11. RBLC Summary for $PM_{2.5}$ Control for the Small Diesel-Fired Engine

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

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

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

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

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

(c) Federal Emission Standards
The theory behind federal emission standards for the small diesel-fired engine was discussed in detail in the $PM_{2.5}$ BACT section for the large diesel-fired engines and will not be repeated here. The Department considers federal emission standards a technically feasible control technology for the small diesel-fired engines.

(d) Limited Operation
The theory behind limited operation for the small diesel-fired engine was discussed in detail in the $PM_{2.5}$ BACT section for the large diesel-fired engine and will not be repeated here. The Department considers limited operation a technically feasible control technology for the small diesel-fired engines.

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

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

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

(a) Diesel Particulate Filter (85% - 90% Control)
(b) Low Ash/ Sulfur Diesel (25% Control)
(e) Good Combustion Practices (Less than 40% Control)
(c) Federal Emission Standards (0% Control)
(d) Limited Operation (0% Control)

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

Step 4 - Evaluate the Most Effective Controls

UAF BACT Proposal

UAF provided an updated economic analysis on August 16, 2023, for the installation of a DPF on EU 27. The updated cost analysis included a new annual interest rate of 8.5% and a 20-year equipment life, as well as a new capital investment value of $78,210. The updated capital investment value for a DPF was provided by NC Power Systems on April 14, 2023, and replaces the old quote from a preliminary vendor that was obtained in 2015. UAF did not include direct annual costs, including operating labor, maintenance labor, and maintenance materials. Therefore, they note that their cost estimate is considered conservatively low. A summary of the analysis is shown below:

Table 4-12. UAF Economic Analysis for Technically Feasible $PM_{2.5}$ Controls

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
DPF	0.36	0.31	$78,210	$8,115	$26,539
Capital Recovery Factor = 0.1038 (8.25% interest rate for a 20-year equipment life)					

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

UAF proposes the following as BACT for $PM_{2.5}$ emissions from the small diesel-fired engine EU 27:

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

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

(c) $PM_{2.5}$ emissions from EU 27 will not exceed 0.15 g/hp-hr.

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

The Department revised the updated cost analysis provided by UAF for the installation of a DPF on EU 27. In addition, the Department added a new cost analysis for the installation of DPF on EU 26, which has the highest baseline emissions of the various small diesel-fired engines at UAF. The Department used the updated NC Power Systems capital investment quote of $78,210 for both engines, updated the annual interest rate to the current bank prime interest rate of 8.5%, updated the potential emissions to those found in the TAR of Minor Permit AQ0316MSS08 and assumed a maximum control efficiency of 90%, and left the 20-year equipment life unchanged for EU 27 and assumed a 15-year equipment life for EU 26. The Department notes that emissions for EU 26 and EU 27 are calculated at 8,760 and 4,380 hours per year respectively. Therefore, the estimated equipment life of 15 and 20 years is a conservative estimate considering EPA's estimate of the typical lifespan of a DPF is 10,000 hours or more.[20] The Department also excluded annual costs related to labor and maintenance of the DPF, which continues the trend of ensuring a conservatively low-cost estimate. A summary of the analyses are shown below:

Table 4-13. Department's Economic Analysis for Technically Feasible $PM_{2.5}$ Controls on EU 26

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Capital Cost ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
DPF	0.61	0.55	$78,210	$9,418	$17,099
Capital Recovery Factor = 0.1204 (8.5% interest rate for a 15-year equipment life)					

Table 4-14. Department Economic Analysis for Technically Feasible $PM_{2.5}$ Controls on EU 27

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Capital Cost ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
DPF	0.45	0.41	$78,210	$8,265	$20,271
Capital Recovery Factor = 0.1057 (8.5% interest rate for a 20-year equipment life)					

The Department's economic analyses indicate that the level of $PM_{2.5}$ reduction does not justify the use of a DPF for the control of $PM_{2.5}$ emissions from the small diesel-fired engines EUs 24, 26, 27, 29, and 34.

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:

[20] EPA's May 2010 technical bulletin on diesel particulate filters, EPA-420-F-10-029: https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=&ved=2ahUKEwjI95b27vOAAxWyMn0KHb4kCn0QFnoECBsQAQ&url=https%3A%2F%2Fwww.epa.gov%2Fsites%2Fdefault%2Ffiles%2F2016-03%2Fdocuments%2F420f10029.pdf&usg=AOvVaw0i3wXeZ0Jd1oAbcVnvTnPQ&opi=89978449.

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

(b) Limit non-emergency operation of EUs 24, 29, and 34 to no more than 100 hours per year each;

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

(d) EUs 27 and 34 shall comply with the federal emission standards of NSPS Subpart IIII, Tier 3 listed in Table 4-15.

Table 4-15. Determination of $PM_{2.5}$ BACT Limits for the Small Diesel-Fired Engines

EU	Year	Description	Size	Status	BACT Limit	Proposed BACT
~~26~~[1]	~~1987~~	~~Mitsubishi Bosh~~	~~64 hp~~	~~AP-42 Table 3.3-1~~	~~1.0 g/hp-hr~~	~~Good Combustion Practices~~
27	2013	Caterpillar C-15	500 Hp	Certified Engine	0.19 g/hp-hr	Limit Operation to 4,380 hours per year and Good Combustion Practices
24	2001	Cummins	72 hp	AP-42 Table 3.3-1	1.0 g/hp-hr	Limit Operation for non-emergency use (100 hours each per year) and Good Combustion Practices
29	2013	Cummins	314 hp	Certified Engine	0.023 g/hp-hr	
34	2015	Cummins	324 hp	Certified Engine	0.19 g/hp-hr	

[1] As of March 23, 2023, UAF reported to EPA that EU 26 has been permanently removed from service at the stationary source. However, the Department left the EU in the BACT determination because it had already performed a cost analysis for DPF on this EU and relied upon it to show that DPF's are not cost effective for lesser emitting units. The Department has however removed this EU from Minor Permit AQ0316MSS08 Rev. 1.

Table 4-16 lists the 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 4-16. Comparison of $PM_{2.5}$ BACT for the Small Engines at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
UAF	Small Diesel-Fired Engines	< 500 hp	**0.023** – 1.0 g/hp-hr	Good Combustion Practices Limited Operation
Fort Wainwright	Small Diesel-Fired Engines	< 500 hp	0.015 – 1.0 g/hp-hr	Good Combustion Practices Limited Operation

4.6 $PM_{2.5}$ BACT for the Pathogenic Waste Incinerator (EU 9A)

Possible $PM_{2.5}$ emission control technologies for waste incinerators were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 21.300 for Hospital, Medical and Infectious Waste Incinerators. The search results for pathogenic waste incinerators are summarized in Table 4-17.

Table 4-17. RBLC Summary of $PM_{2.5}$ Control for Pathogenic Waste Incinerator

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

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

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

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

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

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

(d) Limited Operation
The theory behind the limited operation for EU 9A was discussed in detail in the $PM_{2.5}$ BACT section for the pathogenic waste incinerator and will not be repeated here. The Department considers limited operation a technically feasible control technology for the pathogenic waste incinerator.

(e) Good Combustion Practices
The theory of GCPs was discussed in detail in the $PM_{2.5}$ BACT section for the large dual fuel-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 pathogenic waste incinerator.

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

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

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

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

Step 4 - Evaluate the Most Effective Controls

UAF BACT Proposal

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

Table 4-18. UAF Economic Analysis for Technically Feasible $PM_{2.5}$ Controls

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

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

UAF proposes the following as BACT for $PM_{2.5}$ emissions from the pathogenic waste incinerator:

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

(b) $PM_{2.5}$ emissions from EU 9A shall not exceed 4.67 lb/ton; and

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

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

(a) $PM_{2.5}$ emissions from EU 9A shall be equipped with a multiple chamber design;

(b) Total PM emissions from EU 9A shall not exceed 4.67 lb/ton;[21]

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

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

Table 4-19 lists the BACT determination for this facility along with those for other waste incinerators located in the Serious $PM_{2.5}$ nonattainment area.

Table 4-19. Comparison of $PM_{2.5}$ BACT for Pathogenic Waste Incinerators at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
UAF	One Pathogenic Waste Incinerator	83 lb/hr	4.67 lb/ton 109 tons of waste per 12-month period	Multiple Chambers Good Combustion Practices Limited Operation

4.7 $PM_{2.5}$ BACT for the Material Handling Units (EUs 105, 107, 109 through 111, 114, and 128 through 130)

Possible $PM_{2.5}$ emission control technologies for material handling were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 99.100 - 190, Fugitive Dust Sources. The search results for material handling units are summarized in Table 4-20.

Table 4-20. $PM_{2.5}$ Control for Material Handling Units

Control Technology	Number of Determinations	Emission Limits
Fabric Filter / Baghouse	10	0.05 gr/dscf
Electrostatic Precipitator	3	0.032 lb/MMBtu
Wet Suppressants / Watering	3	29.9 tpy
Enclosures / Minimizing Drop Height	4	0.93 lb/hr

RBLC Review

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

Step 1 - Identification of $PM_{2.5}$ Control Technology for the Material Handling Units

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

(a) Fabric Filters

[21] AP-42 Table 2.3-2. Emission factors for total particulate matter, lead, and TOC for controlled air medical waste incinerators for uncontrolled devices

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

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

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

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

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

(f) Vents/Closed System Vents/Negative Pressure Vents
Vents can control fugitive emissions by collecting fugitive emissions from enclosed loading, unloading, and transfer points and then venting emissions to the atmosphere or back into other equipment such as a storage silo. Other vent control designs include enclosing emission units and operating under a negative pressure. The Department considers vents to be a technically feasible control technology for the material handling

units, except for EU 111. EU 111 does not have collected emissions and the vent system would be ineffective when trucks enter and depart the loading area.

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

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

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

Step 4 - Evaluate the Most Effective Controls

UAF BACT Proposal

UAF proposes the following as BACT for $PM_{2.5}$ emissions from the material handling units:

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

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

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

(d) $PM_{2.5}$ emissions from EU 111 shall not exceed 5.5×10^{-5} lb/ton.

(e) $PM_{2.5}$ emissions from EU 114 shall not exceed 0.05 gr/dscf.

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

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

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

(c) Comply with the numerical emission limits listed in Table 4-21:

Table 4-21. PM2.5 BACT Control Technologies for the Material Handling Units

EU ID	Process Description	Capacity	Limitation	Control Method
105, 107, 109, 110, & 128 - 130	7 Material Handling Units	Varies	0.003 gr/dscf (*)	Fabric Filter & Enclosure & Vent
111	Ash Loadout to Truck	N/A	5.50E-05 lb/ton	Enclosure
114	Dry Sorbent Handing Vent Filter Exhaust	5 acfm	0.05 gr/dscf (*)	Fabric Filter & Enclosure & Vent

(*) 3-hour average.

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 University of Alaska Fairbanks Campus.

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

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

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

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

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

Step 1 - Identification of SO_2 Control Technology for the Large Dual Fuel-Fired Boiler
From research, the Department identified the following technologies as available for control of SO_2 emissions from the large dual fuel-fired boiler:

(a) Flue Gas Desulfurization (FGD)
FGD is a set of technologies used to remove SO_2, acid gases such as hydrogen chloride (HCL), and hazardous air pollutants (e.g., mercury (Hg)), from exhaust flue gases. FGD is a common add-on control technology that uses chemical processes to remove of SO_2 at coal-fired power plants. FGD control systems include wet flue gas desulfurization (WFGD, also called wet scrubbers), spray dry adsorption (SDA), circulating dry scrubber (CDS),

and dry sorbent injection (DSI). These four control technologies are discussed below in detail using information submitted from UAF's BACT analysis and Section 5 – SO_2 and Acid Gas Controls of the EPA Air Pollution Control Cost Manual (EPA CCM).[22]

1. WFGD (Wet Scrubbers)

   A Wet FGD system controls SO_2 emissions using solutions containing alkali reagents. Wet FGD systems may use limestone, lime, sodium-based alkaline, or dual alkali-based sorbents. Wet FGD systems can also be categorized as "once-through" or "regenerable" depending on how the waste solids generated are handled. In a once-through system the spent sorbent is disposed as waste. Regenerable systems recycle the sorbent back into the system and recover the salts for sale as byproduct (e.g., gypsum). Regenerable systems have higher capital costs than once-through systems due to the additional equipment required to separate and dry the recovered salts. However, regenerable systems may be the best option for plants where disposal options are limited or nearby markets for byproducts are available.

   Most WFGD systems use a limestone slurry sorbent which reacts with the SO_2 and falls to the bottom of the absorber tower where it is collected. Wet FGD systems generally have the highest control efficiencies. New wet FGD systems can achieve SO_2 removal of 99% and HCl removal of over 95%. Packed tower wet FGD systems may achieve efficiencies as high as 99.9% for some pollutant-solvent systems.[23]

   WFGD systems are typically located downstream of any particle collection system (baghouse, electrostatic precipitator) and the induced draft fan. WFGD systems are typically located immediately before the flue gas stack. This location allows for fly ash to be removed prior to the absorber thus reducing the amount of solids collected by the falling slurry. This configuration also allows for a "dry" induced draft fan, saving significant capital and maintenance costs given the conditions of the flue gas stream leaving the absorber.

   A wet flue gas desulfurization system has a significant amount of auxiliary equipment in addition to the absorber and slurry recirculation system. This equipment varies greatly between plants depending on the specific needs of the plant and the availability of different forms of the reagents being used. In general, the auxiliary equipment necessary to store, prepare, and handle the reagent includes dry reagent storage silos, weigh feeders, mills, classifiers, and blowers. Spent reagent is typically collected as a slurry from the reservoir and dewatered using vacuum table filters, or similar equipment. The waste solids are either then transported to a landfill or sold for secondary uses (such as in the manufacture of wallboard). The water recovered from the spent reagent is reused in

[22] EPA Air Pollution Control Cost Manual and associated and associated cost spreadsheets are available at the following website: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

[23] EPA Air Pollution Control Cost Manual: Section 5 – SO_2 and Acid Gas Controls, Chapter 1, Page 1-9: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual.

the process to the extent possible. However, a portion of the water must be purged and replaced with fresh water in order to limit the concentrations of chlorides. UAF's analysis assumes that the purged water can be disposed of in the local sewer system, which may not be the case. In the event that the water cannot be disposed of, a zero liquid discharge (ZLD) system will be required. These systems consist of the equipment necessary to concentrate dissolved solids in wastewater streams and then evaporate any remaining water, leaving only solids for disposal.

UAF contacted several vendors to request equipment quotes for a WFGD system on EU 113. UAF was not able to obtain any vendor quotes for appropriate WFGD system equipment. UAF stated that vendors were unwilling to provide estimates and did not understand the rationale for potentially installing WFGD on a CFB boiler with limestone injection that already controls SO_2 emissions. Vendors indicated that a WFGD would not be practical or cost-effective. UAF and its consultants also believe that vendors were unwilling or unable to provide a study-level cost estimate for WFGD equipment because the vendors did not have an existing design for a system sized appropriately for EU 113 which is small when compared to typical coal-fired boilers at utility power plants. UAF stated that developing a study-level cost estimate would have required the investment of significant resources, which the vendors appeared to be unwilling to do. UAF noted, the WFGD cost estimating tool that EPA provides as part of the EPA CCM[24]is intended for boilers that are at least three times the size of EU 113. The lack of vendor input raises doubts as to whether UAF would realistically be able to procure a WFGD system for EU 113 if ultimately required to do so. Given this lack of vendor response, UAF is hesitant to consider WFGD as an available SO_2 emission control technology at this time. However, for the sake of completeness, UAF provided a cost analysis for WFGD using the EPA CCM "Wet and Dry Scrubbers and Acid Gas Control Cost Calculation Spreadsheet."[24] The Department considers WFGD to be a technologically feasible control technology for EU 113.

2. Spray Dry Absorbers (SDA, AKA Dry Lime FGD)
Spray Dry Absorbers are gas absorbers in which a small amount of water is mixed with the sorbent. Lime (CaO) is usually the sorbent used in the spray drying process, but hydrated lime ($Ca(OH)_2$) is also used and can provide greater SO_2 removal. Slurry consisting of lime and recycled solids is atomized/sprayed into the absorber. The SO_2 in the flue gas is absorbed into the slurry and reacts with the lime and fly ash alkali to form calcium salts. The scrubbed gas then passes through a particulate control downstream of the spray drier where additional reactions and SO_2 removal may occur, especially in the filter cake of a fabric filter (baghouse). Spray dryers can achieve SO_2 removal efficiencies up to 95%,[25] depending on the type of coal burned.

[24] EPA Air Pollution Control Cost Manual: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual
[25] EPA Air Pollution Control Cost Manual: Section 5 – SO_2 and Acid Gas Controls, Chapter 1, Table 1.3: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual.

UAF was unable to obtain any vendor quotes for an SDA system for EU 113. UAF stated that vendors indicated that a CDS system would likely have similar costs to an SDA system but provide more effective SO_2 removal. UAF therefore concluded that control system equipment vendors do not appear to provide new SDA systems at this time. The lack of positive vendor input raises doubts as to whether UAF would realistically be able to procure an SDA system for EU 113 if ultimately required to do so. Based on this vendor information, UAF is hesitant to consider SDA as an available SO_2 emission control technology at this time. Considering that UAF did not submit vendor quote for SDA controls because CDS control technology offers a higher SO_2 removal efficiency at a lower price point, the Department agrees with UAF's assessment that SDA is now technologically obsolete for EU 113 and therefore technologically infeasible.

3. Circulating Dry Scrubbers (CDS)

Similar to other dry flue gas desulfurization systems, the CDS system is located after the air preheater, and byproducts from the system are collected in an integrated fabric filter. Unlike the SDA systems, a CDS system is considered a circulating fluidized bed of hydrated lime reagent to remove SO_2 rather than an atomized lime slurry; however, similar chemical reaction kinetics are used in the SO_2 removal process. In a CDS system, flue gas is treated in type of Dry Lime FGD system in which the waste gas stream passes through an absorber vessel where the flue gas stream flows through a fluidized bed of hydrated lime and recycled byproduct. Water is injected into the absorber through a venturi located at the base of the absorber for temperature control. Flue gas velocity through the vessel is maintained to keep the fluidized bed of particles suspended in the absorber. Water sprayed into the absorber cools the flue gas from approximately 300° F at the inlet to the scrubber to approximately 160° F at the outlet of the fabric filter. The hydrated lime absorbs SO_2 from the gas and forms calcium sulfite and calcium sulfate solids. The desulfurized flue gas passing out of the absorber contains solid sorbent mixed with the particulate matter, including reaction products, unreacted hydrated lime, calcium carbonate, and fly ash. The solid sorbent and particulate matter are collected by the fabric filter. CDS can achieve over 98% reduction in SO_2 and other acid gases. [26]

UAF obtained cost estimates for the installation of a CDS control system from Andritz, Babcock Power Environmental Inc. (BPE), and Tri-Mer Corporation (Tri-Mer). Of the three proposals, the Andritz proposal was the most complete. The Tri-Mer proposal was a similar price to Andritz and also provided significant amounts of information. The BPE proposal appeared to be the low bid, but the price was provided in 2017 dollars. The final annual 2021 CEPCI value of 708.0 was used to escalate the BPE price to current day dollars, resulting in the BPE offering being significantly more expensive than the other two quotes. Given the similar pricing between Andritz and Tri-Mer, UAF chose the Andritz system as the quotation to be used in the cost-effectiveness evaluation because the Andritz system did not require consuming any sorbent and so would represent the lowest overall cost. Quoted SO_2 removal efficiencies were similar across the three

[26] EPA Air Pollution Control Cost Manual: Section 5 – SO_2 and Acid Gas Controls, Chapter 1, Page 1-11: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual.

proposals. All three OEMs provided removal efficiencies that were slightly lower than the typical values in the EPA CCM[24], largely because of the very low influent concentration of SO_2. As influent concentrations declines, sorbent particles have more difficulty interacting with the SO_2 molecules and the overall capture efficiency declines. Therefore SO_2 removal efficiency was calculated at 90% for the CDS. The Department considers CDS to be a technologically feasible control technology for EU 113.

4. Dry Sorbent Injection (DSI)
Unlike the three other FGD systems, dry sorbent injection (DSI) is not a stand-alone, add-on air pollution control system but a modification to the combustion unit or ductwork. DSI systems inject a powdered alkaline reagent directly into the flue gas duct ahead of the particle collection device. Where hydrated lime is used as the reagent, the addition of water may be necessary to complete the chemical reaction. These reagents react with the sulfur (and other acid gases) in-flight and on the surfaces of the particle collection device. The products of reaction, unreacted reagent, and fly ash are collected at the bottom of the particle collection device and disposed of through the plants fly ash collection system. Reagents typically utilized in DSI systems include hydrated lime, Trona, and sodium bicarbonate. According to the EPA CCM[27] DSI can achieve SO_2 control efficiencies ranging from 50 to 70% and has been used in power plants, biomass boilers, and industrial applications (e.g., metallurgical industries). However, Solvay, a supplier of sodium bicarbonate and trona based sorbent material for DSI systems, commented on the Fairbanks $PM_{2.5}$ Serious Nonattainment SIP indicating that they have received vendor quotes stating that a 95% reduction in SO_2 emissions can be achieved on coal fired boilers in Alaska. UAF's updated vendor quotes include a 90% control efficiency for DSI via Tri-Mer, and 85% control efficiency via BACT, Inc. The Department considers DSI to be a technologically feasible control technology for EU 113.

(b) Fluidized Bed Limestone Injection (FBLI)
FBLI is considered separate from the other FGD control technologies because the limestone is injected into the boiler as part of the combustion process, as opposed to being injected into the flue gas after the combustion process has been completed. Section 5 (SO_2 and Acid Gas Controls) of the EPA CCM[24] includes a section on FBLI that specifically references EU 113 at the University of Alaska Fairbanks. FBLI is also considered an integral part of the design of EU 113. The FBLI process involves crushed coal and a fluidizing materials such as ground limestone, along with recirculated ash, which are suspended in the boiler by an upward stream of hot air. The coal is combusted in this fluidized mixture. The limestone reacts with SO_2 to form solids (effectively gypsum) that can be captured by the baghouse. FBLI is an available control technology and is already in use on EU 113. The circulating fluidized bed (CFB) technology of EU 113, including FBLI, is considered the base case for this BACT analysis. The initial baseline emissions rate used in the Permittee's analysis is the existing EU 113 SO_2 PTE of 258.9 tpy, the

[27] EPA Air Pollution Control Cost Manual: Section 5 – SO_2 and Acid Gas Controls, Chapter 1, Page 1-11: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual.

rolling 12-month emission limit in Conditions 36.1 and 61.2 of Permit AQ0316TVP03. The limit is based on the New Source Performance Standards (NSPS) SO_2 emission standard of 0.20 pounds per million British thermal unit (lb/MMBtu) in 40 CFR 60.42b(k)(1). As demonstrated by the continuous emissions monitoring system (CEMS) information submitted by the Permittee with their semi-annual reports, the actual SO_2 emission rates have been considerably lower. The Department considers FBLI to be a technologically feasible control technology for EU 113.

(c) Low Sulfur Coal
UAF purchases coal from the Usibelli Coal Mine located in Healy, Alaska. This coal mine is located 115 miles south of Fairbanks. The coal mined at Usibelli is sub-bituminous coal and has a relatively low sulfur content with guarantees of less than 0.4 percent by weight. Usibelli Coal Data Sheets indicate a range of 0.08 to 0.28 percent Gross As Received (GAR) percent Sulfur (%S). According to the U.S. Geological Survey, coal with less than one percent sulfur is classified as low sulfur coal. The Department considers the use of low sulfur coal a technically feasible control technology for the large dual fuel-fired boiler. Because the Permittee already combusts low sulfur coal, this control option represents the baseline emissions rate, or a 0% emissions control.

(d) Good Combustion Practices
The theory of GCPs was discussed in detail in the $PM_{2.5}$ BACT section for the large dual fuel-fired boiler and will not be repeated here. Proper management of the combustion process will result in a reduction of SO_2 emissions. The Department considers GCPs a technically feasible control technology for the large dual fuel-fired boiler.

Step 2 - Eliminate Technically Infeasible SO_2 Controls for the Large Dual Fuel-Fired Boiler
As discussed in Step 1, the Department considers SDA to be technologically infeasible for controlling SO_2 emissions from the large dual fuel-fired boiler at UAF.

Step 3 - Rank the Remaining SO_2 Control Technologies for the Large Dual Fuel-Fired Boiler
The following control technologies have been identified and ranked by efficiency[28] for control of SO_2 emissions from the large dual fuel-fired boiler:

(a-1)	Wet Scrubber	(95% Control)
(a-3)	Circulating Dry Scrubbers	(90% Control)
(a-4)	Dry Sorbent Injection	(85% - 90% Control)
(b)	Fluidized Bed Limestone Injection	(Less than 85% Control)
(d)	Good Combustion Practices	(Less than 40% Control)
(c)	Low Sulfur Coal	(0% Control, Baseline)

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

[28] In ranking the different control efficiencies, the Department used vendor data provided by UAF for EU 113 in a document titled, "Sulfur Dioxide Best Available Control Technology Analysis for Emission Unit 113, January 2023."

Step 4 - Evaluate the Most Effective Controls

UAF BACT Proposal

UAF provided updated economic analyses on February 21, 2023, for the installation of WFGD, CDS, and DSI control technologies. With the updated analyses, UAF obtained new quotes from vendors for the installation of DSI and CDS and was unable to obtain any vendor quotes for WFGD and SDA as the vendors said that these control technologies would not be cost effective compared to DSI and CDS for EU 113.UAF provided a cost analysis for WFGD using the EPA CCM "Wet and Dry Scrubbers and Acid Gas Control Cost Calculation Spreadsheet."[24] UAF's analyses used control efficiencies of 95% for WFGD, 90 for CDS, 90% for DSI via the Tri-Mer quote, and 85% for DSI via the BACT, Inc. quote. Additionally, UAF also performed an incremental cost analysis for the different SO_2 control technologies. For a particular control technology, the incremental cost analysis compares the difference in total annual cost between that technology and the next lowest-ranked technology and divides that value by the difference in emissions reductions between the two technologies. For this analysis, UAF assumed the baseline emission rates to be the current permit limit of 0.20 lb/MMBtu, with the operation of the coal-fired boiler using FBLI. Summaries of these two analyses are shown below in Table 5-2 for the standard cost effectiveness results and Table 5-3 for the incremental cost-effectiveness results. Both analyses include the name of the vendor who provided the quote for the CDS and DSI control systems.

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

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
WFGD	258.9	246.0	$52,968,345	$7,589,888	$30,859
CDS (Andritz)	258.9	233.0	$32,505,815	$5,757,437	$24,709
DSI (Tri-Mer)	258.9	233.0	$5,794,396	$5,193,086	$22,287
DSI (BACT, Inc)	258.9	220.1	$11,565,826	$3,121,966	$14,187
Capital Recovery Factor = 0.0847 (7.5% interest rate for a 30-year equipment life)					

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

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Incremental Cost Effectiveness ($/ton)
WFGD	258.9	246.0	$52,968,345	$7,589,888	$141,557
CDS (Andritz)	258.9	233.0	$32,505,815	$5,757,437	$203,590
DSI (Tri-Mer)	258.9	233.0	$5,794,396	$5,193,086	$159,994
DSI	258.9	220.1	$11,565,826	$3,121,966	$14,187

(BACT, Inc)					
FBLI – Base	258.9	0.0	0.0	0.0	-
Capital Recovery Factor = 0.0847 (7.5% interest rate for a 30-year equipment life)					

UAF contends that the economic analysis indicates the level of SO_2 reduction does not justify the use of WFGD, CDS, or DSI for the dual fuel-fired boiler based on the excessive cost per ton of SO_2 removed per year. However, UAF has proposed a new enforceable limit for EU 113 which has been achieved in practice at the facility using FBLI.

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

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

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

(c) SO_2 emissions from EU 113 will not exceed 0.125 lb/MMBtu on 30-day rolling average basis.

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

The Department revised the cost analyses provided for the installation of wet scrubbers, circulating dry scrubbers, and both dry sorbent injection analyses. For all the analyses, the Department left the 30-year control equipment life unchanged, updated the annual interest rate to 8.5% (current bank prime interest rate), and updated the baseline emissions rate to 0.10 lb/MMBtu. This emissions rate was selected by the Department after evaluating the semi-annual CEMS data for SO_2 emissions from EU 113 for 2022 and 2023. During that time-period, the highest 30-day average rolling emissions occurred during the period of July 1 to December 31 of 2022, with a value of 0.06 lb/MMBtu. The Department chose the SO_2 emissions rates of 0.1 lb/MMBtu after performing a statistical analysis using the highest 30-day average rolling emissions that occurred during each of the semi-annual periods from 2022 through 2023 and using a 99% confidence interval, which resulted in a value of 0.092 lb/MMBtu. The Department rounded up from the 99% confidence interval to a 0.10 lb/MMBtu, which is half of the 0.2 lb/MMBtu existing NSPS Subpart Db limit for EU 113, and matches the limit found on GVEA's Healy EU 2, which is equipped with both DSI and SDA, and is the most stringent SO_2 limit found on a coal-fired boiler in the state of Alaska. The Department notes that UAF proposed a revised SO_2 limit for EU 113 of 0.125 lb/MMBtu in a December 22, 2023, submittal. In UAF's submittal, they noted that EU 113 has had daily average SO_2 emissions as high as 0.564 lb/MMBtu and that the sulfur content of the coal delivered from the Usibelli Coal Mine can vary from 0.08 – 0.28 percent by weight and has averaged 0.129 percent by weight since January 2020. The Department took this into consideration when selecting 0.10 lb/MMBtu as the SO_2 emissions rate. The Department notes that although the daily average emissions rate has been higher than 0.10 lb/MMBtu, that there has been two years' worth of CEMS data that shows an ample margin of compliance with the selected emissions rate on a 30-day rolling basis, which is the averaging period selected for the CEMS equipped EU 113.

Although the Department changed the baseline emissions rate for EU 113, the final controlled emissions rates were left unchanged from the emissions guarantees provided by UAF's vendors, which resulted in a lower assumed control efficiency. No other changes were made to the CDS analysis. For the WFGD analysis, the Department updated the Chemical Engineering Plant Cost Index (CEPCI) to the latest value of 816.0[29] for 2022 prices. Additionally, for the WFGD analysis, in order to demonstrate a conservative approach, the Department used the default values from the EPA CCM for limestone cost, water cost, electricity cost, waste disposal cost, and labor rate. For the two DSI cost analyses, the Department removed the 25% increase in assumed cost for the DSI installation which is accounted for elsewhere in the analysis. Also for the two DSI cost analyses, in order to demonstrate a conservative approach, the Department used the assumed cost percentages from the EPA CCM for the instrumentation, freight, foundations and support, handling and erection, electrical, piping, insulation, painting, engineering, construction and field expenses, contractor fees, start-up, performance tests, contingency, operating and maintenance labor hours, overhead, property tax, and administrative changes and insurance. A summary of the analysis is shown below in Table 5-4.

Table 5-4. Department Economic Analysis for Technically Feasible SO_2 Controls

Control Alternative	Potential to Emit (PTE)	Emission Reduction (tpy)	Total Capital Cost ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
WFGD	129.5	116.5	$60,051,550	$7,939,734	$68,137
CDS (Andritz)	129.5	103.6	$32,505,815	$6,029,814	$58,215
DSI (Tri-Mer)	129.5	103.6	$3,668,667	$4,223,707	$40,778
DSI (BACT, Inc)	129.5	90.6	$14,411,039	$3,203,706	$35,349
Capital Recovery Factor = 0.0931 (8.5% interest rate for a 30-year equipment life)					

The Department's economic analysis indicates the level of SO_2 reduction does not justify the use of any additional SO_2 controls as BACT for the dual fuel-fired boiler located in the Serious $PM_{2.5}$ nonattainment area. However, because the Department assumed a different baseline emissions rate for the cost analyses with the operation of FBLI, that is now selected as BACT.

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

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

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

(b) EU 113 shall not exceed a SO_2 emission rate of 0.10 lb/MMBtu[30] determined on a 30-day rolling average; and

[29] The CEPCI for 2022 is located at the following website: https://toweringskills.com/financial-analysis/cost-indices/.

[30] See the discussion above on how the Department selected an SO_2 emissions rate in Step 4 -Department Evaluation of BACT for SO_2 Emissions from the Dual Fuel-Fired Boiler.

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

Table 5-5 lists the SO_2 BACT determination for this facility along with those for other coal-fired boilers in the Serious $PM_{2.5}$ nonattainment area.

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

Facility	Process Description	Capacity	Limitation	Control Method[31]
UAF	Dual Fuel-Fired Boiler	295.6 MMBtu/hr	0.10 lb/MMBtu[30]	Fluidized Bed Limestone Injection Good Combustion Practices
Fort Wainwright	6 Coal-Fired Boilers	1,380 MMBtu/hr (combined)	0.04 lb/MMBtu[32]	Dry Sorbent Injection Operational Limit
Chena	4 Coal-Fired Boilers	497 MMBtu/hr (combined)	0.301 lb/MMBtu[33]	Good Combustion Practices

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

Possible SO_2 emission control technologies for mid-sized diesel-fired boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 12.220, Industrial Size Distillate Fuel Oil Boilers (>100 MMBtu/hr and ≤ 250 MMBtu/hr). The search results for mid-sized diesel-fired boilers are summarized in Table 5-6.

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

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

Possible SO_2 emission control technologies for mid-sized diesel-fired boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 12.310, Industrial Size Gaseous Fuel Boilers (>100 MMBtu/hr and ≤ 250 MMBtu/hr). The search results for mid-sized diesel-fired boilers are summarized in Table 5-7.

Table 5-7. RBLC Summary of SO_2 Control for Mid-Sized Boilers Firing Natural Gas

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

[32] Fort Wainwright and Chena Power Plants SO_2 emission rates are vendor provided emission guarantees.

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

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

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

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

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

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

(c) Limited Operation
The theory of limited operation for the mid-sized diesel-fired boilers was discussed in detail in the $PM_{2.5}$ BACT section for the mid-sized diesel-fired boilers and will not be repeated here. The Department considers limited operation a technically feasible control technology for the mid-sized diesel-fired boilers.

(d) Good Combustion Practices
The theory of GCPs was discussed in detail in the $PM_{2.5}$ BACT section for the large dual fuel-fired boiler and will not be repeated here. Proper management of the combustion process will result in a reduction of SO_2 emissions. The Department considers GCPs a technically feasible control technology for the mid-sized diesel-fired boilers.

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

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

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

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

Step 4 - Evaluate the Most Effective Controls

UAF BACT Proposal

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

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

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

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

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

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

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

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

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

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

Table 5-8 lists the BACT determination for this facility along with those for other mid-sized diesel-fired boilers located in the Serious $PM_{2.5}$ nonattainment area.

Table 5-8. Comparison of SO_2 BACT for the Mid-Sized Diesel-Fired Boilers at Nearby Power Plants

Facility	EU ID	Process Description	Capacity	Fuel	Limitation	Control Method
UAF	3	Dual Fuel-Fired Boilers	180.90 MMBtu/hr (each)	Diesel	15 ppmw S in fuel	Ultra Low Sulfur Diesel
	4			Diesel	15 ppmw S in fuel	Limited Operation
				Natural Gas	0.60 lb/MMscf	Ultra Low Sulfur Diesel

5.3 SO_2 BACT for the Small Diesel-Fired Boilers (EUs 17 through 22)

Possible SO_2 emission control technologies for small diesel-fired boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 13.220, Commercial/Institutional Size Boilers (<100 MMBtu/hr). The search results for small diesel-fired boilers are summarized in Table 5-9.

Table 5-9. RBLC Summary of SO_2 Control for Small Diesel-Fired Boilers

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

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

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

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

(b) Limited Operation
The theory behind limited operation was discussed in detail in the $PM_{2.5}$ BACT section for the small diesel-fired boilers and will not be repeated here. The Department considers limited operation as a technically feasible control technology for the small diesel-fired boilers.

(c) Good Combustion Practices
The theory of GCPs was discussed in detail in the $PM_{2.5}$ BACT section for the large dual fuel-fired boiler and will not be repeated here. Proper management of the combustion process will result in a reduction of SO_2. The Department considers GCPs a technically feasible control technology for the small diesel-fired boilers.

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

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

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

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

Step 4 - Evaluate the Most Effective Controls

UAF BACT Proposal

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

(a) SO_2 emissions from the operation of the small diesel-fired boilers EUs 19 through 22 will be controlled by limiting the combined operation to no more than 18,739[34] hours per 12-month rolling period;

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

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

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

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

(a) SO_2 emissions from EUs 19 through 22 will be controlled by limiting the combined operation to no more than 18,739 hours per 12-month rolling period; and

(b) SO_2 emissions from the diesel-fired boilers EUs 17 through 22[35] shall be controlled by combusting only ULSD.

Table 5-10 lists the SO_2 BACT determination for this facility along with those for other small diesel-fired boilers rated at less than 100 MMBtu/hr in the Serious $PM_{2.5}$ nonattainment area.

Table 5-10. Comparison of SO_2 BACT for the Small Diesel-Fired Boilers at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
Fort Wainwright	<u>4</u> Diesel-Fired Boilers (*)	< 100 MMBtu/hr	15 ppmw S in fuel	Limited Operation Good Combustion Practices Ultra-Low Sulfur Diesel
UAF	6 Diesel-Fired Boilers	< 100 MMBtu/hr	15 ppmw S in fuel	Limited Operation Ultra-Low Sulfur Diesel
GVEA Zehnder	2 Diesel-Fired Boilers	< 100 MMBtu/hr	15 ppmw S in fuel	Good Combustion Practices Ultra-Low Sulfur Diesel

(*) The number of diesel fired boilers was updated in this BACT Amendment by removing those boilers that are considered insignificant emission units

[34] UAF originally proposed a combined operating limit of 19,650 hr/yr in their original BACT submittal, but this limit was changed to 18,739 combined hours of operation per 12-month rolling period with the issuance of AQ0316MSS07 on August 10, 2021.

[35] EUs 17, 18, and 22 required by Condition 5 of AQ0316MSS07 and 40 of AQ0316TVP03, EUs 19 through 21 required by Condition 9 of AQ0316MSS04 and 30 of AQ0316TVP03.

5.4 SO_2 BACT for the Large Diesel-Fired Engines (EUs 8 and 35)

Possible SO_2 emission control technologies for large engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 17.100 - 17.190, Large Internal Combustion Engines (>500 hp). The search results for large diesel-fired engines are summarized in Table 5-11.

Table 5-11. RBLC Summary Results for SO_2 Control for Large Diesel-Fired Engines

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

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

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

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

(b) Federal Standards
The theory of federal emission standards was discussed in detail in the $PM_{2.5}$ BACT section for the large diesel-fired engines and will not be repeated here. The Department does not consider federal emission standards a technically feasible control technology for the large diesel-fired engine EU 8.

(c) Limited Operation
EU 8 currently operates under a combined annual NOx emission limit with EU 4. Limiting the operation of emissions units reduces the potential to emit of those units. Additionally, EU 35 is currently restricted by the NSPS Subpart IIII requirements for emergency engines. Therefore, the Department considers limited operation a technically feasible control technology for the large diesel-fired engines.

(d) Good Combustion Practices
The theory of GCPs was discussed in detail in the $PM_{2.5}$ BACT section for the large dual fuel-fired boiler and will not be repeated here. Proper management of the combustion

process will result in a reduction of SO_2 emissions. The Department considers GCPs a technically feasible control technology for the large diesel-fired engine.

Step 2 - Eliminate Technically Infeasible SO_2 Control Technologies for the Large Diesel-Fired Engines

As explained in Step 1 of Section 5.4, the Department does not consider federal emission standards as a technically feasible control technology to control SO_2 emissions from the large diesel-fired engine EU 8.

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

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

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

Step 4 - Evaluate the Most Effective Controls

UAF BACT Proposal

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

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

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

Step 5 - Selection of SO_2 BACT for the Large Diesel Fired-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 EUs 8 and 35 shall be controlled by combusting only ULSD (0.0015 weight percent sulfur);

(b) Limit the combined operation of EU 4 and 8 to no more than 40 tons of SO_2 per 12-month rolling average;

(c) Limit non-emergency operation of EUs 8 and 35 to no more than 100 hours per year; and

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

Table 5-12 lists the 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 5-12. 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

Facility	Process Description	Capacity	Limitation	Control Method
				Good Combustion Practices Ultra-Low Sulfur Diesel
UAF	2 Large Diesel-Fired Engines	> 500 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 fuel15	Good Combustion Practices Ultra-Low Sulfur Diesel
GVEA Zehnder	2 Large Diesel-Fired Engines	11,000 hp	ppmw S in fuel	Good Combustion Practices Ultra-Low Sulfur Diesel

5.5 SO_2 BACT for the Small Diesel-Fired Engines (EUs 24, 26, 27, 29, and 34)

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 5-13.

As of March 23, 2023, UAF reported to EPA that EU 26 has been permanently removed from service at the stationary source.

Table 5-13. RBLC Summary of SO_2 Controls for Small Diesel-Fired Engines

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

RBLC Review

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

Step 1 - Identification of SO_2 Control Technology for the Small Diesel-Fired Engines

From research, the Department identified the following technologies as available for control of SO_2 emissions from diesel-fired engines rated at less than 500 hp:

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

(b) Limited Operation
The theory of limited operation for EU 27 was discussed in detail in the $PM_{2.5}$ BACT section for the large diesel-fired engine and will not be repeated here. The Department considers limited operation a technically feasible control technology for the small diesel-fired engines.

(c) Good Combustion Practices
The theory of GCPs was discussed in detail in the $PM_{2.5}$ BACT section for the large dual fuel-fired boiler and will not be repeated here. Proper management of the combustion process will result in a reduction of SO_2 emissions. The department considers GCPs a technically feasible control technology for the small diesel-fired engines.

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

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

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

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

Step 4 - Evaluate the Most Effective Controls

UAF BACT Proposal

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

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

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

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

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

Step 5 - Selection of SO_2 BACT for the Small Diesel-Fired Engines
The Department's finding is that BACT for SO_2 emissions from the small diesel-fired engines is as follows:

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

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

(c) Limit non-emergency operation of EUs 24, 29, and 34 to no more than 100 hours per year each; and

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

Table 5-14 lists the 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 5-14. Comparison of SO_2 BACT for Small Diesel-Fired Engines at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
Fort Wainwright	Small Diesel-Fired Engines	< 500 hp	15 ppmw S in fuel	Limited Operation Ultra-Low Sulfur Diesel Good Combustion Practices
UAF	Small Diesel-Fired Engines	< 500 hp	15 ppmw S in fuel	Limited Operation[36] Ultra-Low Sulfur Diesel Good Combustion Practices

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

Possible SO_2 emission control technologies for pathogenic waste incinerators were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 21.300 for Hospital, Medical, and Infectious Waste Incinerators. The search results for pathogenic waste incinerators are summarized in Table 5-15.

Table 5-15. RBLC Summary of SO_2 Control for the Pathogenic Waste Incinerator

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

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

Step 1 - Identification of SO_2 Control Technology for the Pathogenic Waste Incinerator
From research, the Department identified the following technologies as available for control of SO_2 emissions from pathogenic waste incinerators:

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

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

(c) Limited Operation
The theory behind the limited operation for EU 9A was discussed in detail in the $PM_{2.5}$ BACT section for the large dual fuel-fired boilers and will not be repeated here. The Department considers limited operation a technically feasible control technology for the pathogenic waste incinerator.

(d) Good Combustion Practices
The theory of GCPs was discussed in detail in the $PM_{2.5}$ BACT section for the large dual fuel-fired boiler and will not be repeated here. Proper management of the combustion process will result in a reduction of SO_2 emissions. The Department considers GCPs a technically feasible control technology for the pathogenic waste incinerator.

Step 2 - Eliminate Technically Infeasible SO_2 Control Technologies for the Pathogenic Waste Incinerator
Natural gas is eliminated as a technically infeasible SO_2 control technology for the pathogenic waste incinerator due to the limited availability.

Step 3 - Rank the Remaining SO_2 Control Technologies for the Pathogenic Waste Incinerator
The following control technologies have been identified and ranked by efficiency for the control of SO_2 emissions from the pathogenic waste incinerator:

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

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

Step 4 - Evaluate the Most Effective Controls

UAF BACT Proposal

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

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

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

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

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

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

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

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

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

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

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

6. BACT DETERMINATION SUMMARY

Table 6-1. NOx BACT Limits

EU ID	Description	Capacity	Proposed BACT Limit	Proposed BACT Control
All	N/A	N/A	EPA approved a comprehensive precursor demonstration for NOx See details in the Section 1 Introduction	

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

EU ID	Description	Capacity	Proposed BACT Limit		Proposed BACT Control
3	Mid-Sized Diesel-Fired Boiler	180.9 MMBtu/hr	0.012	lb/MMBtu, 3-hour average	Good Combustion Practices
4	Mid-Sized Diesel-Fired Boiler	180.9 MMBtu/hr	Diesel: 0.012	lb/MMBtu, 3-hour average	Limited Operation (EUs 4 and 8 combined 40 tons per rolling 12 month period); Good Combustion Practices
			NG: 0.0075	lb/MMBtu, 3-hour average	
8	Large Diesel-Fired Engine	13,226 hp	0.32	g/hp-hr , 3-hour average	Positive Crankcase Ventilation; Good Combustion Practices Limited Operation (EUs 4 and 8 combined 40 tons per rolling 12 month period) and EU 8 to no more than 100 hours of non-emergency operation per year; and ULSD
9A	Pathogenic Waste Incinerator	83 lb/hr	4.67	lb/ton	Multiple Chambers; Limited Operation (109 tons per rolling 12 month period); Good Combustion Practices
17	Small Diesel-Fired Boiler	4.93 MMBtu/hr	0.016	lb/MMBtu	Good Combustion Practices
18	Small Diesel-Fired Boiler	4.93 MMBtu/hr	0.016	lb/MMBtu	
19	Small Diesel-Fired Boiler	6.13 MMBtu/hr	0.016	lb/MMBtu	Limited Operation (18,739 hours per rolling 12 month period combined) Good Combustion Practices
20	Small Diesel-Fired Boiler	6.13 MMBtu/hr	0.016	lb/MMBtu	
21	Small Diesel-Fired Boiler	6.13 MMBtu/hr	0.016	lb/MMBtu	
22 (*)	Small Diesel-Fired Boiler	8.5 MMBtu/hr	0.016	lb/MMBtu	
~~26~~	~~Small `Diesel-Fired Engine~~	~~45 kW~~	~~1.0~~	~~g/hp-hr~~	~~Good Combustion Practices~~
27	Caterpillar C-15	500 hp	0.19	g/hp-hr	Good Combustion Practices Limited Operation (4,380 hours per year)
24	Cummins	72 hp	1.0	g/hp-hr	Limit Operation for non-emergency use (100 hours each per year) Good Combustion Practices
29	Cummins	314 hp	0.023	g/hp-hr	
34	Cummins	324 hp	0.19	g/hp-hr	

35	Cummins	1,220 hp	0.015 g/hp-hr , 3-hour average	Limit Operation for non-emergency use (100 hours each per year), Positive Crankcase Ventilation, ULSD, and Good Combustion Practices
105	Material Handling Unit	1,200 acfm	0.003 gr/dscf	Fabric Filters Enclosures Vents
107	Material Handling Unit	1,600 acfm	0.003 gr/dscf	
109	Material Handling Unit	1,000 acfm	0.003 gr/dscf	
110	Material Handling Unit	2,000 acfm	0.003 gr/dscf	
111	Material Handling Unit	N/A	5.5×10^{-5} lb/ton	Enclosure
113	Large Dual Fuel-Fired Boiler	295.6 MMBtu/hr	0.012 lb/MMBtu, 3-hour average	Fabric Filters Good Combustion Practices
114	Material Handling Unit	5 acfm	0.05 gr/dscf	Fabric Filters Enclosures Vents
128	Material Handling Unit	1,650 acfm	0.003 gr/dscf	
129	Material Handling Unit	1,650 acfm	0.003 gr/dscf	
130	Material Handling Unit	1,650 acfm	0.003 gr/dscf	

(*) UAF reported that this EU has been permanently removed from service

Table 6-3. SO_2 BACT Numerical Limits

EU ID	Description	Capacity	Proposed BACT Limit	Proposed BACT Control
3	Mid-Sized Diesel-Fired Boiler	180.9 MMBtu/hr	15 ppmw S in Fuel	Ultra-Low Sulfur Diesel Good Combustion Practices.
4	Mid-Sized Diesel-Fired Boiler	180.9 MMBtu/hr	Diesel: 15 ppmw S in Fuel NG: 0.60 lb/MMscf	Ultra-Low Sulfur Diesel Limited Operation (EUs 4 and 8 combined 40 tons per rolling 12 month period) Good Combustion Practices.
8	Large Diesel-Fired Engine	13,226 hp	15 ppmw S in Fuel	Limited Operation (EUs 4 and 8 combined 40 tons per rolling 12 month period) and EU 8 to no more than 100 hours of non-emergency operation per year Good Combustion Practices and ULSD

EU ID	Description	Capacity	Proposed BACT Limit	Proposed BACT Control
9A	Pathogenic Waste Incinerator	83 lb/hr	15 ppmw S in Fuel	Ultra-Low Sulfur Diesel Limited Operation (109 tons per rolling 12 month period) Good combustion practices
17	Small Diesel-Fired Boiler	4.93 MMBtu/hr	15 ppmw S in Fuel	Ultra-Low Sulfur Diesel
18	Small Diesel-Fired Boiler	4.93 MMBtu/hr	15 ppmw S in Fuel	
19	Small Diesel-Fired Boiler	6.13 MMBtu/hr	15 ppmw S in Fuel	Limited Operation (18,739 hours per rolling 12 month period combined) Ultra-Low Sulfur Diesel
20	Small Diesel-Fired Boiler	6.13 MMBtu/hr	15 ppmw S in Fuel	
21	Small Diesel-Fired Boiler	6.13 MMBtu/hr	15 ppmw S in Fuel	
22	Small Diesel-Fired Boiler	8.5 MMBtu/hr	15 ppmw S in Fuel	Ultra-Low Sulfur Diesel
~~26 (*)~~	~~Small `Diesel-Fired Engine~~	~~45 kW~~	~~15 ppmw S in Fuel~~	~~Good Combustion Practices and ULSD~~
27	Caterpillar C-15	500 hp	15 ppmw S in Fuel	Good Combustion Practices and ULSD Limited Operation (4,380 hours per year)
24	Cummins	51 kW	15 ppmw S in Fuel	Limit Operation for non-emergency use (100 hours each per year), Good Combustion Practices and ULSD
29	Cummins	314 hp	15 ppmw S in Fuel	
34	Cummins	324 hp	15 ppmw S in Fuel	
35	Cummins	1,220 hp	15 ppmw S in Fuel	
113	Large Dual Fuel-Fired Boiler	295.6 MMBtu/hr	0.10 lb/MMBtu (30-day rolling average)	Good Combustion Practices, Fluidized Bed Limestone Injection[31]

(*) UAF reported that this EU has been permanently removed from service

Stationary Source: University of Alaska – University of Alaska Fairbanks Campus

Emission Units: EU ID 113 (295.6 MMBtu/hr – Large Dual Fuel-Fired Boiler)

Pollutant of Concern: SO_2	
BACT Control	**Monitoring, Recordkeeping and Reporting Requirements** [1]
0.10 lb/MMBtu (30-day rolling average);	• Compliance with the proposed SO_2 emission rate for the dual fuel-fired boiler will be demonstrated through CEMS monitoring and reporting. • Install, calibrate, maintain, and operate CEMS for measuring SO_2 concentrations and either O_2 or CO_2 concentrations according to the requirements of NSPS 40 CFR Subpart Db for CEMS that may be used to meet the SO_2 emission monitoring requirements of 40 C.F.R. 60.47b. • Record the CEMS data and include the recorded data in each semi-annual operating report.
Good Combustion Practices.	• Perform regular maintenance according to the manufacturer's and the operator's maintenance requirements and procedures. • Keep records of any maintenance that would have a significant effect on emissions. The records may be kept in electronic format. • Keep a copy of the manufacturer's and the operator's recommended maintenance procedures. • Report a summary of the maintenance that would have a significant effect on emissions in each operating report.
Control emissions with fluidized bed with limestone injection (FBLI) at all times of operation.	• Certify in semi-annual Operating Report that the FBLI system is operated at all times the boiler is in operation. • Operate, maintain, and inspect according to the manufacturer's instructions and recommendations. • Include a summary of inspections and maintenance conducted in each semi-annual operating report.

Emission Units: EU ID 3 (180.9 MMBtu/hr – Mid-Sized Diesel-Fired Boiler) and EU ID 4 (180.9 MMBtu/hr – Mid-Sized Dual Fuel-Fired Boiler)

Pollutant of Concern: SO_2	
BACT Control	**Monitoring, Recordkeeping and Reporting Requirements** [1]
Combust only Ultra Low Sulfur Diesel (ULSD) at no more than 0.0015 percent sulfur by weight.	• For each shipment of fuel, keep receipts that specify fuel grade and amount. • Include the fuel receipt records in each operating report.
0.60 lb/MMscf for EU ID 4 (while firing natural gas);	• Obtain a semiannual statement providing the H_2S concentration in ppmv. If not available, analyze semiannually a representative sample of the natural gas to determine the H_2S content. • Keep records of statement and/or analysis.

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

	• Report statement and/or analysis results. • Report whenever limit exceeded or whenever requirements not met.
Limit the combined SO_2 emissions from EUs 4 and 8 to no more than 40 tons per 12-month rolling period.	• Demonstrate compliance with this BACT measure by complying with Condition 3 through 3.6 of Minor Permit No. AQ0316MSS05.
Good Combustion Practices.	• Perform regular maintenance according to the manufacturer's and the operator's maintenance requirements and procedures. • Keep records of any maintenance that would have a significant effect on emissions. The records may be kept in electronic format. • Keep a copy of the manufacturer's and the operator's recommended maintenance procedures. • Report a summary of the maintenance that would have a significant effect on emissions in each operating report.

Emission Units: EU IDs 17 through 22 (<100 MMBtu/hr – Small Diesel-Fired Boilers)

Pollutant of Concern: SO_2	
BACT Control	**Monitoring, Recordkeeping and Reporting Requirements** [1]
Combust Only Ultra Low Sulfur Diesel (ULSD) at no more than 0.0015 percent sulfur by weight.	• For each shipment of fuel, keep receipts that specify fuel grade and amount. • Include the fuel receipt records in each operating report.
For EUs 19 through 22, limit the combined operation to no more than 18,739 hours per 12-month rolling period.	• Demonstrate compliance with this BACT measure by complying with Condition 7.1 through 7.2 of Minor Permit No. AQ0316MSS07.

Emission Units: EU IDs 8 and 35 (>500 hp – Large Diesel-Fired Engines)

Pollutant of Concern: SO_2	
BACT Control	**Monitoring, Recordkeeping and Reporting Requirements** [1]
Combust Only Ultra Low Sulfur fuel at no more than 0.0015 percent sulfur by weight.	• For each shipment of fuel, keep receipts that specify fuel grade and amount. • Include the fuel receipt records in each operating report.
Limited NO_x emissions from EUs 4 and 8 to no more than 40 tons per 12-month rolling period.	• Demonstrate compliance by complying with Conditions 3 through 3.6 of Minor Permit No. AQ0316MSS05.
Limited non-emergency operation of EUs 8 and 35 to no more than 100 hours per year, each.	• Maintain and operate a non-resettable hour meter, capable of recording the total hours of operation.

	• By the end of each calendar month, record the total operating hours of the EU for the previous calendar month; and for the previous 12 consecutive months. • Report the operating hours record for each engine in each operating report.
Good Combustion Practices.	• Perform regular maintenance according to the manufacturer's and the operator's maintenance requirements and procedures. • Keep records of any maintenance that would have a significant effect on emissions. The records may be kept in electronic format. • Keep a copy of the manufacturer's and the operator's recommended maintenance procedures. • Report a summary of the maintenance that would have a significant effect on emissions in each operating report.

Emission Units: EU IDs 24, 27, 29, and 34 (<500 hp – Small Diesel-Fired Engines)

Pollutant of Concern: SO_2	
BACT Control	**Monitoring, Recordkeeping and Reporting Requirements** [1]
Combust Only Ultra Low Sulfur fuel at no more than 0.0015 percent sulfur by weight.	• For each shipment of fuel, keep receipts that specify fuel grade and amount. • Include the fuel receipt records in each operating report.
Limited operation for EU 27 to no more than 4,380 hours per 12-month rolling period.	• Demonstrate compliance with this BACT measure by complying with Conditions 4 through 4.1 of Minor Permit No. AQ0316MSS03.
Limited non-emergency operation for EUs 24, 29, and 34 to no more than 100 hours per year, each.	• Maintain and operate a non-resettable hour meter, capable of recording the total hours of operation. • By the end of each calendar month, record the total operating hours of the EU for the previous calendar month; and for the previous 12 consecutive months. • Report the operating hours record for each engine in each operating report.
Good Combustion Practices.	• Perform regular maintenance according to the manufacturer's and the operator's maintenance requirements and procedures. • Keep records of any maintenance that would have a significant effect on emissions. The records may be kept in electronic format. • Keep a copy of the manufacturer's and the operator's recommended maintenance procedures. • Report a summary of the maintenance that would have a significant effect on emissions in each operating report.

Emission Units: EU ID 9A (Pathogenic Waste Incinerator)

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

Combust Only Ultra Low Sulfur fuel at no more than 0.0015 percent sulfur by weight.	• For each shipment of fuel, keep receipts that specify fuel grade and amount. • Report in each semi-annual operating report, the fuel receipts records for the reporting period.
Limit operation of EU 9A to no more than 109 tons of waste combusted per 12-month rolling period.	• Demonstrate compliance with this BACT measure by complying with Condition 10.1c of Minor Permit No. AQ0316MSS08 Rev. 1.
Good Combustion Practices.	• Demonstrate compliance with this BACT measure by complying with Condition 10.1a of Minor Permit No. AQ0316MSS08 Rev. 1. •

DEPARTMENT OF ENVIRONMENTAL CONSERVATION

AIR QUALITY CONTROL MINOR PERMIT

Minor Permit: AQ0316MSS08 Revision 1 **Final Date - October 31, 2024**
Rescinds Permit: AQ0316MSS08

The Alaska Department of Environmental Conservation (Department), under the authority of AS 46.14 and 18 AAC 50, issues Air Quality Control Minor Permit AQ0316MSS08 Revision 1 to the Permittee listed below.

Permittee:	**University of Alaska Fairbanks (UAF)** PO Box 757920 Fairbanks, AK 99775
Stationary Source:	**University of Alaska Fairbanks Campus (UAF Campus)**
Location:	802 Alumni Drive, Fairbanks, Alaska 99709 Latitude: 64° 51' North; Longitude: 147° 51' West
Project:	Serious PM-2.5 State Implementation Plan (SIP)
Permit Contact:	Russ Steiger Phone No.: 907-474-5812 email: rsteiger@alaska.edu

The Permittee submitted an application for Minor Permit AQ0316MSS08 under AS 46.14.130(c)(2) because the Department finds that public health or air quality effects provide a reasonable basis to regulate the stationary source. This finding is contained in the State Air Quality Control Plan adopted on November 19, 2019.

With the issuance of AQ0316MSS08 Revision 1, The Department finds that public health or air quality effects still provide a reasonable basis to regulate the stationary source under AS 46.14.130(c)(2). This finding is contained in the State Air Quality Control Plan adopted on November 19, 2019, for the $PM_{2.5}$ Serious Nonattainment area.

This permit satisfies the obligation of the Permittee to obtain a minor permit under 18 AAC 50. As required by AS 46.14.120(c), the Permittee shall comply with the terms and conditions of this permit.

The Department's Performance Audits for COMS (as adopted by reference in 18 AAC 50.030, August 20, 2008), has been adopted into this minor permit.

The following conditions have been adopted into this minor permit: 3 through 3.6 of Minor Permit AQ0316MSS05 issued on August 4, 2016, 7.1 through 7.2 of Minor Permit AQ0316MSS07 issued on August 10, 2021, and 4 through 4.1 of Minor Permit AQ0316MSS03 issued on January 16, 2013.

P. Moses Coss for

James R. Plosay, Manager
Air Permits Program

Table of Contents

List of Abbreviations and Acronyms

AAAQS..................... Alaska Ambient Air Quality Standards
ADEC.......................Alaska Department of Environmental Conservation
AS .... Alaska Statutes
AAC .... Alaska Administrative Code
ACEP .... Alaska Center for Energy and Power
BiRD .... Biological Research and Diagnostics Facility
BACM....................... Best Available Control Measures
BACT........................ Best Available Control Technology
C.F.R......................... Code of Federal Regulations
COMS .... Continuous Opacity Monitoring System
CEMS........................ Continuous Emission Monitoring System
Department................ Alaska Department of Environmental Conservation
EF.............................. Emission Factor
EU .... Emission Unit
FG .... Fuel Gas
FNSB .... Fairbanks North Star Borough
GHG.......................... Greenhouse gas
LPG........................... Liquefied Petroleum Gas
NA............................. not applicable
NESHAP .... National Emissions Standards for Hazardous Air Pollutants
NG............................. natural gas
NSPS......................... New Source Performance Standards
ORL .... owner requested limit
PSD .... Prevention of Significant Deterioration
PTE .... Potential to Emit
SIP............................. State Implementation Plan
SER .... significant emissions rate
TAR .... Technical Analysis Report
ULSD........................ Ultra-Low Sulfur Diesel

Units and Measures

acfm .... actual cubic feet per minute
dscf............................ dry standard cubic foot
gal/hr .... gallons per hour
gal/yr .... gallons per year
gr/dscm...................... grains per dry standard cubic meter
hp .... horsepower
hr/yr........................... hours per year
lb/gal .... pounds per gallon
lb/kgal .... pounds per kilogallon
kW............................. kilowatts
lb/hr........................... pounds per hour
MMBtu/hr .... million British thermal units per hour
ppm .... parts per million
ppmw .... parts per million by weight
scf.............................. standard cubic foot
TPY .... tons per year
% .... percent
wt%S_{fuel} .... weight percent of sulfur in Fuel

Pollutants and Chemical Symbols

CO .... Carbon Monoxide
HAP .... hazardous air pollutant
NO_x .... Oxides of Nitrogen
O_2 .... Oxygen
PM............................. Particulate Matter
PM_{10} .... Particulate Matter with an aerodynamic diameter not exceeding 10 microns
$PM_{2.5}$.......................... Particulate Matter with an aerodynamic diameter not exceeding 2.5 microns
SO_2 .... Sulfur Dioxide
VOC .... Volatile Organic Compound

Section 1 Emissions Unit Inventory

Emissions Unit (EU) Authorization. Unless otherwise noted in this permit, the information in Table 1 is for identification purposes only. The specific EU descriptions do not restrict the Permittee from replacing an EU identified in Table 1.

Table 1 – Emissions Unit Inventory[1]

EU ID	Building No.	Emissions Unit Description	Rating/Size	Fuel Type	Installation or Construction Date
Dual Fuel-Fired and Fuel Oil-Fired Boilers					
3	FS802	Dual-Fired Boiler (Zurn)	180.9 MMBtu/hr	Dual Fuel (Gas/Diesel)	1970
4	FS802	Dual-Fired Boiler (Zurn)	180.9 MMBtu/hr	Dual Fuel (Gas/Diesel)	1987
17	FS909	West Ridge Research Bld. Diesel Boiler #1 (Weil McLain/BL1688w-GPr10)	4.93 MMBtu/hr	Diesel	2003
18	FS909	West Ridge Research Bld. Diesel Boiler #2 (Weil McLain/BL1688w-GPr10)	4.93 MMBtu/hr	Diesel	2003
19	FS919	BiRD Rm 100U3 Boiler #1 (Weil McLain/2094W)	6.13 MMBtu/hr	Diesel	2004
20	FS919	BiRD Rm 100U3 Boiler #2 (Weil McLain/2094W)	6.13 MMBtu/hr	Diesel	2004
21	FS919	BiRD Rm 100U3 Boiler #3 (Weil McLain/2094W)	6.13 MMBtu/hr	Diesel	2004
22	FS919	BiRD Rm 100U3 Boiler #4 (Bryan/EB200-S-150-FDGO)	8.5 MMBtu/hr	Diesel	2005
Diesel-Fired Engines					
8	FS817	Peaking/Backup Generator (Morse Colt-Pielstick)	13,266 Hp	ULSD	1999
24	FS423	Old University Park Emergency Generator Engine (Cummins/4B3.9-G2)	72 Hp[2]	#2 Diesel	2001
27	FS814	Alaska Center for Energy and Power Generator Engine No. 2 (Caterpillar C-15)	500 Hp	Diesel	2013
29	FS901	Arctic Health Research Emergency Generator Engine (Cummins/QSB7-G6)	314 Hp	Diesel	2013
34	FS919	BiRD Emergency Diesel Generator Engine No. 1 (Cummins QSB7-G5 NR3 Engine, EPA Tier 3, Model Year 2011)	324 Hp	Diesel	2015
35	SW910	Butrovich Adm. Building Emergency Generator Engine (Cummins QSK23-G7 NR2 Engine, EPA Tier 2, Model Year 2018)	1,220 Hp	ULSD	2019
Pathogenic Waste Incinerator					
9A	FS919	BiRD Incinerator (Therm-Tec/G-30P-1H)	83 lb/hr	Medical/ Infectious Waste	2006

EU ID	Building No.	Emissions Unit Description	Rating/Size	Fuel Type	Installation or Construction Date
Dual Fuel-Fired CFB Boiler (EU ID 113) and Associated Coal and Ash Handling Equipment					
105	FS840	Limestone Handling System for Boiler No. 1	1,200 acfm	NA	2018
107	FS840	Sand Handling System	1,600 acfm	NA	2018
109	FS840	Ash Handling System	1,000 acfm	NA	2018
110	FS840	Ash Handling System Vacuum	2,000 acfm	NA	2018
111	FS840	Ash Loadout to Truck	NA	NA	2018
113	FS840	Dual Fuel-Fired Circulating Fluidized Bed (CFB) Boiler	295.6 MMBtu/hr	Coal/Woody Biomass	2018
114	FS840	Dry Sorbent Handling Vent Filter Exhaust	5 acfm	NA	2018
128	FS840	Coal Silo No. 1 with Bin Vent	1,650 acfm	NA	2018
129	FS840	Coal Silo No. 2 with Bin Vent	1,650 acfm	NA	2018
130	FS840	Coal Silo No. 3 with Bin Vent	1,650 acfm	NA	2018

Table Notes:

[1] Only the EUs with new operating limits and conditions due to this permit appear in Table 1.
[2] Engine rating in Hp is calculated from the electrical output assuming 95 pct. efficiency (i.e., Hp = kW * 1.341/0.95).

1. The Permittee shall comply with all applicable provisions of AS 46.14 and 18 AAC 50 when installing a replacement EU, including any applicable minor or construction permit requirements**.**

Section 3 State Implementation Plan (SIP) Requirements

Fairbanks $PM_{2.5}$ Serious Nonattainment Area SIP Requirements

5. Dual Fuel-Fired Boiler Emissions Limits. The Permittee shall limit the emissions from the dual fuel-fired boiler EU ID 113 as specified in Table 2.

Table 2 - EU ID 113 SIP BACT Limits

Pollutant	BACT Control	BACT Emissions Limit
$PM_{2.5}$	Good Combustion Practices Fabric Filters	0.012 lb/MMBtu (3-hour average) State Visible Emissions Standards 18 AAC 50.055(a)(1)

5.1 For EU ID 113 the Permittee shall

a. Conduct a one-time source test on EU ID 113, after the control device, in accordance with Section 6, within 12 months of permit issuance, to demonstrate compliance with the $PM_{2.5}$ emissions limit listed in Table 2.

(i) Conduct the source test at the maximum achieveable load of the boiler in accordance with the procedures specified in 40 CFR 51, Appendix M, Methods 201 A and, if applicable, Method 202 as provided under Method 201-A.

(ii) Emission results shall be reported as the arithmetic 3-hour average of all valid test runs and shall be in units of lb/MMBtu.

(iii) The Permittee shall report the results of the source test in accordance with Condition 33.

(iv) Include a summary of the source test results in the next operating report that is due after the submittal date of the source test report in accordance with Condition 18.

b. Report the compliance status with the $PM_{2.5}$ emissions limits in Table 2 in accordance with each annual compliance certification described in Condition 19.

c. Operate the EU with fabric filters and maintain good good combustion practices at all times of operation.

(i) Keep records of the date and time identifying each time-period that the EU is operated without a fabric filter.

(ii) Perform regular maintenance according to the manufacturer's and the operator's maintenance requirements and procedures.

(iii) Keep records of any maintenance that would have a significant effect on emissions. The records may be kept in electronic format

(iv) Keep a copy of the manufacturer's and the operator's maintenance procedures.

(v) Operate the EU consistent with manufacturer's recommended combustion settings (e.g., maximum CO, excess air in flue gas, and other relevant parameters) or those established during the source test conducted to demonstrate compliance with the BACT emissions limit in Table 2.

d. Monitor visible emissions to ensure compliance with the State Visible Emissions Standard in Table 2 using a Continuous Opacity Monitoring System (COMS).

(i) The Permittee shall comply with the following procedures when monitoring visible emissions using a COMS:

(A) The COMS must meet the performance specifications in 40 C.F.R. 60, Appendix B, Performance Specification 1;

(B) operate and maintain the COMS in accordance with the manufacturer's written requirements and recommendations;

(C) except during COMS breakdowns, repairs, calibration checks, and zero and upscale adjustments, complete one cycle of sampling and analyzing for each successive 15-second period of emissions unit operation; from this data, calculate and record the average opacity for each successive one-minute period; and

(D) at least once daily, conduct a zero and upscale (span) calibration drifts check in accordance with a written procedure, as described in 40 C.F.R. 60.13(d); adjust whenever the zero or upscale drift error exceeds four percent opacity in a 24-hour period.

(E) The Permittee shall conduct performance audits as follows:

(1) for a COMS that was new, relocated, replaced, or substantially refurbished on or after April 9, 2001, perform an audit that includes the following elements as described in the Department's Performance Audits for COMS (available at https://dec.alaska.gov/air/air-permit/standard-conditions/), adopted by reference in 18 AAC 50.030, at least once in each 12-month period:

1. optical alignment;

2. zero and upscale response assessment;

3. zero compensation assessment;

4. calibration error check; and

5. zero alignment assessment;

(2) for a COMS that was new, relocated, replaced, or substantially refurbished before April 9, 2001, perform the same audits required under Condition 5.1d(i)(E)(1) except that Conditions 5.1d(i)(E)(1)1 through 5.1d(i)(E)(1)4 must be performed at least quarterly; this frequency may be reduced if

1. the Permittee demonstrates, by applying measurable criteria to the results of quarterly audits, that quarterly audits are not necessary; and

2. the Department gives written approval for the reduction in frequency.

e. Report in accordance with Condition

(i) a summary of the maintenance records collected under Condition 5.1c(iii); and

(ii) the highest 6-minute average opacity measured by the COMs during the reporting period under Condition 5.1d.

f. Report in accordance with Conditon 17, whenever

(i) an emissions rate determined by the source test required by Condition 5.1a exceeds the limit in Table 2;

(ii) a boiler is operated without a fabric filter as recorded in Condition 5.1c(i); or

(iii) any of Conditions 5.1a through 5.1e are not met.

6. Mid-Sized Diesel-Fired Boilers. The Permittee shall limit the emissions from the mid-sized diesel-fired boilers EU IDs 3 and 4 as specified in Table 3.

Table 3 - EU IDs 3 and 4 SIP BACT Limits

EU ID	Pollutant	BACT Control	Fuel Type	BACT Emissions Limit
3	$PM_{2.5}$	Good Combustion Practices and Limited Operation	Diesel Fuel	0.012 lb/MMBtu
4			Diesel Fuel	0.012 lb/MMBtu
			Natural Gas	0.0075 lb/MMBtu

6.1 For EU IDs 3 and 4, the Permittee shall:

a. Conduct a one-time source test on EU IDs 3 or 4 on diesel fuel and EU ID 4 on natural gas, in accordance with Section 6, within 12 months of permit issuance, to demonstrate compliance with the $PM_{2.5}$ emissions limit listed in Table 3.

(i) Conduct the source test at the maximum achieveable load of the boiler in accordance with the procedures specified in 40 CFR 51, Appendix M, Method 201A and, if applicable, Method 202 as provided under Method 201A.

(ii) Emission results shall be reported as the arithmetic 3-hour average of all valid test runs and shall be in units of lb/MMBtu.

(iii) The Permittee shall report the results of the source test in accordance with Condition 33.

(iv) Include the the following in the next operating report in accordance with Condition 18, that is due after the submittal date of the source test report:

(A) a summary of the source test results; and

(B) relevant combustion settings (including but not limited to average CO and O_2 concentrations in the flue gas) established during the source test that demonstrates compliance with the BACT $PM_{2.5}$ emissions limit in Table 3.

b. Report the compliance status with the $PM_{2.5}$ emissions limits in Table 3 in accordance with each annual compliance certification described in Condition 19.

c. Maintain good combustion practices at all time the EUs are in operation.

(i) Perform regular maintenance according to the manufacturer's and the operator's maintenance requirements and procedures.

(ii) Keep records of any maintenance that would have a significant effect on emissions. The records may be kept in electronic format.

(iii) Keep a copy of the manufacturer's and the operator's maintenance procedures.

(iv) Report in accordance with Condition 18, a summary of the maintenance records collected under Condition 6.1c(ii).

(v) Operate the EUs consistent with manufacturer's recommended combustion settings (e.g., maximum CO, excess air in flue gas, and other relevant parameters) or those established during the source test conducted to demonstrate compliance with the BACT emissions limit in Table 3.

(A) For each of EU IDs 3 and 4, measure and record the CO and O_2 concentrations in the exhaust stream using a portable handheld combustion analyzer during or within 30 days after the end of a calendar quarter that the EU operates.[1]

(B) Include copies of the records required by Condition 6.1c(v)(A) for the reporting period, in each operating report required by Condition 18.

d. Report in accordance with Conditon 17, whenever

(i) an emissions rate determined by the source test required by Condition 6.1a exceeds the limit in Table 3; or

(ii) any of Conditions 6.1a through 6.1c are not met.

6.2 For EU IDs 4 and 8, the Permittee shall comply with Conditions 3 through 3.6 of Minor Permit AQ0316MSS05, issued August 4, 2016.

7. **Diesel-Fired Boilers Emissions Limits.** The Permittee shall limit the emissions from the diesel-fired boilers, EU IDs 17 through 22, as specified in Table 4**.**

[1] It is not the Department's intention to require the Permittee to start up an EU just to perform the CO and O_2 concentration measurements.

Table 4 - EU IDs 17 through 22 SIP BACT Limits

Pollutant	BACT Control	Fuel Type	BACT Emissions Limit
$PM_{2.5}$	Good Combustion Practices and Limited Operation	Diesel	0.016 lb/MMBtu (3-hour average)

7.1 For EU IDs 17 through 22, the Permittee shall demonstrate compliance with the $PM_{2.5}$ BACT emissions limit contained in Table 4 as follows:

a. Maintain good combustion practices at all times the EUs are in operation.

(i) Perform regular maintenance according to the manufacturer's and the operator's maintenance requirements and procedures.

(ii) Keep records of any maintenance that would have a significant effect on emissions. The records may be kept in electronic format.

(iii) Keep a copy of the manufacturer's and the operator's maintenance procedures.

b. Report the compliance status with the $PM_{2.5}$ emissions limit in Table 4 in accordance with each annual compliance certification described in Condition 19.

c. Report under Condition 18, a summary of the maintenance records collected under Condition 7.1a(ii).

d. Report in accordance with Condition 17, whenever

(i) an emissions rate exceeds the limit in Table 4; or

(ii) any of Conditions 7.1a through 7.1c are not met.

7.2 For EU IDs 19 through 22, the Permittee shall comply with Conditions 7.1 through 7.2 of Minor Permit AQ0316MSS07, issued August 10, 2021.

8. Large Diesel-Fired Engines Emissions Limits. The Permittee shall limit the emissions from the large diesel-fired engines, EU IDs 8 and 35, as specified in Table 5.

Table 5 - EU IDs 8 and 35 SIP BACT Limits

EU ID	Pollutant	BACT Control	BACT Emissions Limit
8	$PM_{2.5}$	Good Combustion Practices, Positive Crankcase Ventilation, Limited Operation, and Combust ULSD	0.32 g/hp-hr (3-hour average)
35			0.05 g/hp-hr (3-hour average)

8.1 For EU IDs 8 and 35, the Permittee shall demonstrate compliance with the $PM_{2.5}$ BACT emissions limits contained in Table 5 as follows:

a. Maintain good combustion practices at all times the EUs are in operation.

(i) Perform regular maintenance according to the manufacturer's and the operator's maintenance requirements and procedures.

(ii) Keep records of any maintenance that would have a significant effect on emissions. The records may be kept in electronic format.

(iii) Keep a copy of the manufacturer's and the operator's maintenance procedures.

b. Combust only ULSD (fuel sulfur limit of 15 ppmw). Monitor, record, and report as follows:

(i) For each shipment of fuel, keep receipts that specify fuel grade and amount.

c. Maintain a positive crankcase ventilation (PCV) system at all times the EUs operate in accordance with the manufacturer's and operator's recommended operating and maintenance procedures.

(i) Submit an initial certification that the PCV systems listed in Table 5 has been installed or is an inherent design to the EUs, in the first operating report due after permit issuance, as required by Condition 18.

d. Limit the maintenance checks, readiness testing, and non-emergency operation of each EU to 100 hours per calendar year.

(i) For EU IDs 8 and 35, monitor, record, and report as follows:

(A) Maintain and operate a non-resettable hour meter, capable of recording the total hours of operation.

(B) By the end of each calendar month, record the total operating hours of the EU

(1) for the previous calendar month; and

(2) for the previous 12 consecutive months, as calculated using the records obtained under Condition 8.1d(i)(B)(1).

e. Report the compliance status with the $PM_{2.5}$ emissions limits in Table 5 in accordance with each annual compliance certification described in Condition 19.

f. Report in accordance with Condition 18

(i) a summary of the maintenance records collected under Condition 8.1a(ii);

(ii) the fuel receipt records required by Condition 8.1b(i); and

(iii) the operating hour records for each engine collected under Condition 8.1d(i)(B)(2).

g. Report in accordance with Condition 17, whenever

(i) an emissions rate exceeds the limit in Table 5; or

(ii) any of Conditions 8.1a through 8.1f are not met.

8.2 For EU ID 8, the Permittee shall comply with Condition 6.2.

9. Small Diesel-Fired Engines Emissions Limits. The Permittee shall limit the emissions from the large diesel-fired engines, EU IDs 24, 27, 29, and 34, as specified in Table 6.

Table 6 - EU IDs 24, 27, 29, and 34 SIP BACT Limits

EU ID	Pollutant	BACT Control	BACT Emissions Limit
24	$PM_{2.5}$	Good Combustion Practices and Limited Operation	1.0 g/hp-hr (3-hour average)
27 & 34			0.19 g/hp-hr (3-hour average)
29			0.023 g/hp-hr (3-hour average)

9.1 For EU IDs 24, 27, 29, and 34, the Permittee shall demonstrate compliance with the $PM_{2.5}$ BACT emissions limits contained in Table 6 as follows:

a. Maintain good combustion practices at all times the EUs are in operation.

(i) Perform regular maintenance according to the manufacturer's and the operator's maintenance requirements and procedures.

(ii) Keep records of any maintenance that would have a significant effect on emissions. The records may be kept in electronic format.

(iii) Keep a copy of the manufacturer's and the operator's maintenance procedures.

b. For EU IDs 24, 29, and 34, Limit the maintenance checks, readiness testing, and non-emergency operation of each EU to 100 hours per calendar year.

(i) For EU IDs 24, 29, and 34 monitor, record, and report as follows:

(A) Maintain and operate a non-resettable hour meter, capable of recording the total hours of operation.

(B) By the end of each calendar month, record the total operating hours of the EU

(1) for the previous calendar month; and

(2) for the previous 12 consecutive months, as calculated using the records obtained under Condition 8.1d(i)(B)(1).

c. Report in accordance with Condition 18

(i) a summary of the maintenance records collected under Condition 9.1a(ii); and

(ii) the operating hour records for each engine collected under Condition 9.1b(i)(B)(2).

d. Report the compliance status with the $PM_{2.5}$ emissions limits in Table 6 in accordance with each annual compliance certification described in Condition 19.

e. Report in accordance with Condition 17, whenever

(i) an emissions rate exceeds the limit in Table 6; or

(ii) Any of Conditions 9.1a through 9.1d are not met.

9.2 For EU ID 27, the Permittee shall comply with Conditions 4 through 4.1 of Minor Permit AQ0316MSS03, issued January 16, 2013.

10. Incinerator Emissions Limits. The Permittee shall limit the $PM_{2.5}$ emissions from the incinerator EU ID 9A as specified in Table 7.

Table 7 - EU ID 9A SIP BACT Limits

Pollutant	BACT Control	BACT Emissions Limit
$PM_{2.5}$	Good Combustion Practices Multi Chamber Design Limited Operation	4.67 lb per ton of waste 109 tons per 12-month rolling period

10.1 For EU ID 9A, the Permittee shall demonstrate compliance with the $PM_{2.5}$ requirements in Table 7 as follows:

a. Maintain good combustion practices at all times the EU is in operation.

(i) Perform regular maintenance according to the manufacturer's and the operator's maintenance requirements and procedures.

(ii) Keep records of any maintenance that would have a significant effect on emissions. The records may be kept in electronic format.

(iii) Keep a copy of the manufacturer's and the operator's maintenance procedures.

b. Control $PM_{2.5}$ emissions by using a multiple chamber designed incinerator.

c. Weigh and record the weight of each batch of waste combusted in EU ID 9A

(i) by the end of each calendar month, calculate and record the total quantity of waste combusted for the previous month in tons; and

(ii) for the previous 12 consecutive months, as calculated using the records obtained under Condition 10.1c(i).

d. Report in accordance with Condition 18

(i) a summary of the maintenance records collected under Condition 10.1a(ii);

(ii) a statement indicating whether EU ID 9A is equipped with at least primary and secondary combustion chambers;

(iii) the quantity of monthly waste combusted under Condition 10.1c(i); and

(iv) the rolling 12-month quantity of waste combusted under Condition 10.1c(ii).

e. Report the compliance status with the $PM_{2.5}$ emissions limits in Table 7 in accordance with each annual compliance certification described in Condition 19.

f. Report in accordance with Condition 17 whenever

(i) a limit in Table 7 is exceeded, or

(ii) whenever any of the requirements in Conditions 10.1a through 10.1e are not met.

11. Material Handling Units Emissions Limits. The Permittee shall limit the $PM_{2.5}$ emissions from the material handling units EU IDs 105, 107, 109, 110, 114, and 128 through 130 as specified in Table 8.

Table 8 - EU IDs 105, 107, 109, 110, 114, and 128 through 130 SIP BACT Limits

EU IDs	Pollutant	BACT Control	BACT Emissions Limit
105, 107, 109, 110, and 128 through 130	$PM_{2.5}$	Fabric Filter, Enclosure, & Vents	0.003 gr/dscf
114			0.050 gr/dscf

11.1 For EU IDs 105, 107, 109, 110, and 128 through 130, the Permittee shall demonstrate compliance with the $PM_{2.5}$ requirements in Table 8 as follows:

a. Operate the EUs with fabric filters and vents at all times of operation.

(i) Keep records of the date and time identifying each time period that an EU is operated without a fabric filter or vent.

(ii) Perform regular maintenance regular maintenance according to the manufacturer's and the operator's maintenance requirements and procedures.

(iii) Keep records of any maintenance that would have a significant effect on emissions. The records may be kept in electronic format.

(iv) Keep a copy of the manufacturer's and the operator's maintenance procedures.

b. Operate the EUs in an enclosure.

(i) Keep records of the date and time identifying each time period that an EU is operated outside of an enclosure.

c. For each of the EUs, the Permittee shall within six months of issuance of this permit either:

(i) provide vendor data documenting that EU IDs 105, 107, 109, 110, 114, and 128 through 130 meet the emission limits of Table 8; or

(ii) perform an initial Method 9 observation. For all Method 9 observations, observe emissions unit exhaust for 18 consecutive minutes to obtain a minimum of 72 consecutive 15-second opacity observations in accordance with Method 9 of 40 C.F.R. 60, Appendix A-4; or

(iii) documentation of the previous submittal where the obligations of Conditions 11.1c(i) or 11.1c(ii) were met.

d. If the 18 consecutive minutes of the initial Method 9 observations conducted under Condition 11.1c(ii) result in an 18-minute average opacity greater than 10 percent for EU IDs 105, 107, 109, 110, or 128 through 130, or 20 percent for EU ID 114, the Permittee shall conduct a $PM_{2.5}$ source test in accordance with the methods and procedures specified in 40 C.F.R. 60 Appendix A and Section 6 to determine the $PM_{2.5}$ emission rate.

(i) If required under Condition 11.1d, the Permittee shall report the results of source test(s) in accordance with Condition 33.

(ii) If required under Condition 11.1c(ii), include copies of the results of initial Method 9 observations conducted under Condition 11.1c(ii) in the first operating report required under Condition 18.

e. Report the the compliance status with the $PM_{2.5}$ emissions limits in Table 8 in accordance with each annual compliance certification described in Condition 19.

f. Report in accordance with Condition 18 a summary of the records collected under Condition 11.1a(iii).

g. Report in accordance with Condition 17, whenever

(i) an emissions rate exceeds a limit in Table 8;

(ii) an EU is operated without a fabric filter as recorded in Condition 11.1a(i);

(iii) an EU is operated outside of an enclosure as recorded in Condition 11.1b(i); or

(iv) whenever any of the requirements in Conditions 11.1a through 11.1f are not met.

12. Ash Loadout to Truck EU ID 111. The Permittee shall limit the $PM_{2.5}$ emissions from the ash loadout to truck EU ID 111 as specified in Table 9.

Table 9 - EU ID 111 SIP BACT Limits

Pollutant	BACT Control	BACT Emissions Limit
$PM_{2.5}$	Enclosure	5.50E-05 pound per ton of ash

12.1 For EU ID 111, the Permittee shall demonstrate compliance with the $PM_{2.5}$ requirements in Table 9 as follows:

a. Operate EU ID 111 in an enclosure during all ash loadout operations.

(i) Monitor that overhead door(s) at coal ash loading building are closed while loading the trucks. Monitor that ash truck bodies are free of ash before they leave the building, and that their loads are tarped before they leave the building area. Minimize fugitive dust from coal ash handling operations.

(ii) Keep records of the date and time identifying each time period that EU ID 111 was not enclosed during ash loadout operations.

b. Report the the compliance status with the $PM_{2.5}$ emissions limit in Table 9 in accordance with each annual compliance certification described in Condition 18.

c. Report in accordance with Condition 17; whenver

(i) a limit in Table 9 is exceeded; or

(ii) whenever any of the requirements in Conditions 12.1a through 12.1b are not met.

Section 4 Recordkeeping, Reporting, and Certification Requirements

13. Recordkeeping Requirements. The Permittee shall keep all records required by this permit for at least five years after the date of collection, including:

13.1 Copies of all reports and certifications submitted pursuant to this section of the permit; and

13.2 Records of all monitoring required by this permit, and information about the monitoring including:

a. the date, place, and time of sampling or measurements;

b. the date(s) analyses were performed;

c. the company or entity that performed the analyses;

d. the analytical techniques or methods used;

e. the results of such analyses; and

f. the operating conditions as existing at the time of sampling or measurement.

14. Certification. The Permittee shall certify any permit application, report, affirmation, or compliance certification submitted to the Department and required under the permit by including the signature of a responsible official for the permitted stationary soruce following the statement: *"Based on information and belief formed after resonable inquiry, I certify that the statements and information in and attached to this document are true, accurate, and complete."* Excess emission reports must be certified either upon submittal or with an operating report for the same reporting period. All other reports and other documents must be certified upon submittal.

14.1 The Department may accept an electronic signature on an electronic application or other electronic record required by the Department if the person providing the electronic signature

a. uses a security procedure, as defined in AS 09.80.190, that the Department has approved; and

b. accepts or agrees to be bound by an electronic record executed or adopted with that signature.

15. Submittals. Unless otherwise directed by the Department or this permit, the Permittee shall submit to the Department one certified copy of reports, compliance certifications, and/or other submittals required by this permit. The Permittee may submit the documents electronically or by hard copy.

15.1 Submit the certified copy of reports, compliance certifications, and/or other submittals in accordance with the submission instructions on the Department's Standard Permit Conditions web page at http://dec.alaska.gov/air/air-permit/standard-conditions/standard-condition-xvii-submission-instructions/.

16. Information Requests. The Permittee shall furnish to the Department, within a reasonable time, any information the Department requests in writing to determine whether cause exists to modify, revoke, reissue, or terminate the permit or to determine compliance with the permit. Upon request, the Permittee shall furnish to the Department copies of records required to be kept by the permit. The Department may require the Permittee to furnish copies of those records directly to the federal administrator.

17. Excess Emissions and Permit Deviation Reports. The Permittee shall report excess emissions and permit deviations as follows:

17.1 **Excess Emissions Reporting.** The Permittee shall report all emissions or operations that exceed emissions standards or limits of this permit as follows:

a. In accordance with 18 AAC 50.240(c), as soon as possible, report

(i) excess emissions that present a potential threat to human health or safety; and

(ii) excess emissions that the Permittee believes to be unavoidable.

b. In accordance with 18 AAC 50.235(a), within two working days after the event commenced or was discovered, report an unavoidable emergency, malfunction, or nonroutine repair that causes emissions in excess of a technology-based emission standard.

c. If a continuous or recurring excess emissions is not corrected within 48 hours of discovery, report within 72 hours of discovery unless the Department provides written permission to report under Condition 17.1d.

d. Report all other excess emissions not described in Conditions 17.1a, 17.1b, and 17.1c within 30 days after the end of the month during which the excess emissions occurred or as part of the next routine operating report in Condition 18 for excess emissions that occurred during the period covered by the report, whichever is sooner.

e. If requested by the Department, the Permittee shall provide a more detailed written report to follow up on an excess emissions report.

17.2 **Permit Deviations Reporting.** For permit deviations that are not "excess emissions," as defined under 18 AAC 50.990:

a. Report all other permit deviations within 30 days after the end of the month during which the deviation occurred or as part of the next routine operating report in Condition 18 for permit deviations that occurred during the period covered by the report, whichever is sooner.

17.3 **Reporting Instructions.** When reporting either excess emissions or permit deviations, the Permittee shall report using the Department's online form for all such submittals, beginning no later than September 7, 2023. The form can be found at the Division of Air Quality's Air Online Services (AOS) system webpage http://dec.alaska.gov/applications/air/airtoolsweb using the Permittee Portal option. Alternatively, upon written Department approval, the Permittee may submit the form contained in Section 7 of this permit. The Permittee must provide all information called for by the form that is used. Submit the report in accordance with the submission instructions on the Department's Standard Permit Conditions webpage found at http://dec.alaska.gov/air/air-permit/standard-conditions/standard-conditions-iii-and-iv-submission-instructions/.

18. Operating Reports. During the life of this permit[2], the Permittee shall submit to the Department an operating report in accordance with Conditions 14 and 15 by August 1 for the period January 1 to June 30 of the current year and by February 1 for the period July 1 to December 31 of the previous year.

18.1 The operating report must include all information required to be in operating reports by other conditions of this permit, for the period covered by the report.

18.2 When excess emissions or permit deviations that occurred during the reporting period are not included with the operating report under Condition 18, the Permittee shall identify

a. the date of the excess emissions or permit deviation;

b. the equipment involved;

c. the permit condition affected;

d. a description of the excess emissions or permit deviation; and

e. any corrective action or preventive measures taken and the date(s) of such actions; or

18.3 when excess emissions or permit deviation reports have already been reported under Condition 17 during the period covered by the operating report, the Permittee shall either

a. include a copy of those excess emissions or permit deviation reports with the operating report; or

b. cite the date(s) of those reports.

18.4 The operating report must include, for the period covered by the report, a listing of emissions monitored under Conditions 11.1d which trigger additional testing or monitoring, whether or not the emissions monitored exceed an emission standard. The Permittee shall include in the report

a. the date of the emissions;

b. the equipment involved;

c. the permit condition affected; and

d. the monitoring result which triggered the additional monitoring.

19. Annual Compliance Certification. Each year by March 31, the Permittee shall compile and submit to the Department an annual compliance certification report according to Condition 15.

19.1 Certify the compliance status of the stationary source over the preceding calendar year consistent with the monitoring required by this permit, as follows:

a. identify each term or condition set forth in Section 2 through Section 6, that is the basis of the certification;

b. briefly describe each method used to determine the compliance status;

[2] *Life of this permit* is defined as the permit effective dates, including any periods of reporting obligations that extend beyond the permit effective dates. For example, if a permit expires prior to the end of a calendar year, there is still a reporting obligation to provide operating reports for the periods when the permit was in effect.

c. state whether compliance is intermittent or continuous; and

d. identify each deviation and take it into account in the compliance certification.

19.2 In addition, submit a copy of the report directly to the Clean Air Act Compliance Manager, US EPA Region 10, ATTN: Air Toxics and Enforcement Section, Mail Stop: 20-C04, 1200 Sixth Avenue, Suite 155, Seattle, WA 98101-3188.

Section 6 General Source Test Requirements

26. Requested Source Tests. In addition to any source testing explicitly required by this permit, the Permittee shall conduct source testing as requested by the Department to determine compliance with applicable permit requirements.

27. Operating Conditions. Unless otherwise specified by an applicable requirement or test method, the Permittee shall conduct source testing

27.1 at a point or points that characterize the actual discharge into the ambient air; and

27.2 at the maximum rated burning or operating capacity of the emissions unit or another rate determined by the Department to characterize the actual discharge into the ambient air.

28. Reference Test Methods. The Permittee shall use the following references for test methods when conducting source testing for compliance with this permit:

28.1 Source testing for the reduction in visibility through the exhaust effluent must be conducted in accordance with the procedures set out in 40 C.F.R. 60, Appendix A, Reference Method 9. The Permittee may use the form in Attachment 1 of this permit to record data.

28.2 Source testing for emissions of total particulate matter, sulfur compounds, nitrogen compounds, carbon monoxide, lead, volatile organic compounds, fluorides, sulfuric acid mist, municipal waste combustor organics, metals and acid gases must be conducted in accordance with the methods and procedures specified in 40 C.F.R. 60, Appendix A.

28.3 Source testing for emissions of PM_{10} and $PM_{2.5}$ must be conducted in accordance with the procedures specified in 40 C.F.R. 51, Appendix M, Methods 201 or 201A and 202.

28.4 Source testing for emissions of any contaminant may be determined using an alternative method approved by the Department in accordance with 40 C.F.R. 63 Appendix A, Method 301.

29. Excess Air Requirements. To determine compliance with this permit, standard exhaust gas volumes must include only the volume of gases formed from the theoretical combustion of the fuel, plus the excess air volume normal for the specific emissions unit type, corrected to standard conditions (dry gas at 68° F and an absolute pressure of 760 millimeters of mercury).

30. Test Deadline Extension. The Permittee may request an extension to a source test deadline established by the Department. The Permittee may delay a source test beyond the original deadline only if the extension is approved in writing by the Department's appropriate division director or designee.

31. Test Plans. Before conducting any source tests, the Permittee shall submit a plan to the Department. The plan must include the methods and procedures to be used for sampling, testing, and quality assurance and must specify how the emissions unit will operate during the test and how the Permittee will document that operation. The Permittee shall submit a complete plan within 60 days after receiving a request under Condition 26 and at least 30 days before the scheduled date of any test unless the Department agrees in writing to some other time period. Retesting may be done without resubmitting the plan.

32. Test Notification. At least 10 days before conducting a source test, the Permittee shall give the Department written notice of the date and time the source test will begin.

33. Test Reports. Within 60 days after completing a source test, the Permittee shall submit one certified copy of the results in the format set out in the *Source Test Report Outline*, adopted by reference in 18 AAC 50.030. The Permittee shall certify the results in the manner set out in Condition 13. If requested in writing by the Department, the Permittee must provide preliminary results in a shorter period of time specified by the Department.