Chena Power Plant BACT Appendix Documents

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1. 10.21.24 Final Chena BACT Determination
2. 10.21.24 Chena Power Plant SO2 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 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.

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Reviewed by: Moses Coss
Final Date: October 21, 2024

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Abbreviations/Acronyms

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

Units and Measures

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

Pollutants

CO .... Carbon Monoxide
HAP .... Hazardous Air Pollutant
NOx .... Oxides of Nitrogen
SO_2 .... Sulfur Dioxide
$PM_{2.5}$ .... Particulate Matter with an aerodynamic diameter not exceeding 2.5 microns
PM_{10} .... Particulate Matter with an aerodynamic diameter not exceeding 10 microns

1. INTRODUCTION

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

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

[2] 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.

Adopted Date

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.