From:	David Fish
To:	Dec Air Comment
Subject:	Aurora Energy, LLC"s Comments on Draft SIP
Date:	Friday, July 26, 2019 2:48:19 PM
Attachments:	AE Comments on Draft SIP 07262019.pdf BACT Analysis Addendum - Ind Eng Eval_Final_20190402.pdf

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To whom it may concern,

Attached are comments provided to the DEC from Aurora on the draft State Implementation Plan for the Fairbanks North Star Borough Fine Particulate Nonattainment Area and enclosure.

Sincerely,

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July 26, 2019

c/o Cindy Heil
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Subject: Aurora Energy, LLC's (Aurora) Formal Comment to Proposed Regulation Changes Relating to Fine Particulate Matter ($PM_{2.5}$); Including New and Revised Air Quality Controls and State Implementation Plan (SIP).

The DEC released on May 14, 2019 for public review, the Serious Area State Implementation Plan (SIP) for the Fairbanks North Star Borough (FNSB) Fine Particulate ($PM_{2.5}$) Nonattainment Area (NAA). Public comments are due by 5:00 pm on July 26, 2019. Aurora Energy, LLC (Aurora) appreciates the opportunity to comment on the SIP and the collaborative effort with the Alaska Department of Environmental Conservation (ADEC) to provide a means to attain the $PM_{2.5}$ 24-hour standard that is sensitive to the economics of industries and the communities affected.

1 General Comments

Per the Clean Air Act (CAA), the Serious SIP was supposed to be submitted on December 31, 2017 to describe the Best Available Control Measures (BACM) bringing the area into attainment by December 31, 2019. The 2016 $PM_{2.5}$ Implementation rule allows states to request a 5-year extension of the attainment date (i.e., December 31, 2024) as part of the Serious SIP if attainment is not anticipated by December 31, 2019. Within the 5-year attainment date extension request, the state would outline Most Stringent Measures (MSM) to be applied towards bringing the area into attainment by December 31, 2024. However, if a request is not accepted by the EPA and the area does not meet attainment by the Serious Area attainment date (December 31, 2019) then the Clean Air Act is prescriptive and requires a plan to reduce the concentration of $PM_{2.5}$ by five percent annually. A plan is to be submitted one year after the attainment date (i.e., December 31, 2020) with details on how a 5% annual reduction will be achieved. What has been communicated through the Serious SIP draft is that the most expeditious attainment date for the area is 2029.

5% Reduction Plan

Issue: The DEC is required to submit a 5% reduction plan by December 31, 2020 which hasn't been communicated to the community and/or industry.

Request: As soon as practical, communicate the details of the plan to industry and the community.

Background:

The details of a 5% plan, or at least the outline of such a plan should be better communicated with the community. There is a lack of clarity in what measures the plan would propose. The assumption is the 5% plan will be more stringent than what is being proposed within the Serious SIP.

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Device Requirements

Issue: DEC is adopting emission rates for solid fuel heating devices and requirements that do not give all devices equal consideration. Installation of coal-fired heating devices are not allowed unless they are a listed device (18 AAC50.079). There are no standards available in the regulations for the determination of a qualifying coal-fired heating device. Certain devices are not given options for installation within the regulation. Non-pellet fueled wood-fired hydronic heaters, although may have EPA certification under Subpart QQQQ, are not allowed to be installed within the nonattainment area per 18 AAC 50.077 (b) & (c).

Request:

- Develop standards to qualify the installation of coal-fired heating units. Suggested standard should be consistent with 18 g/h emission rate for existing units or 0.10 lbs/MMBtu [heat input basis] whichever is greater.
- Allow the installation of non-pellet fueled wood-fired hydronic heaters provided they are EPA certified.

Background:

The DEC is adopting several different emission rates for solid fuel heating devices which does not give all devices an equal consideration. There are EPA standards for wood stoves and hydronic heaters; also alternative standards for cordwood fired hydronic heaters.[1] These standards should be adopted without alteration. Both wood stoves and pellet fired hydronic heaters emission rates in the SIP are consistent with the 40 CFR Part 60, Subpart QQQQ standard for wood heating devices. The standards are set by the EPA and apply to manufacturers of the wood heating devices. Any such device that is approved by the EPA should be allowed in the nonattainment area, this includes outdoor hydronic heaters. Existing residential and smaller commercial coal-fired devices are required to be removed by December of 2024 and new coal-fired devices are prohibited from installation within the nonattainment area.[2] Coal-fired devices currently installed can be subject to an in-use source test to demonstrate the device meets the standard of 18 g/h of total particulate matter. This standard should also be the criteria for new residential and smaller commercial coal-fired devices. The 18 g/h standard is consistent with 0.10 lbs/MMBtu (heat input) emission rate for a unit that is rated at 400,000 Btu/hr. The Titan II auger-fed coal boilers are rated at 440,000 Btu/hr (heat output) and have undergone testing through OMNI Test Labs; the same lab that derived emission rates for the DEC which are being used in the nonattainment area SIPs. The OMNI test conducted in 2011 demonstrated that auger-fed coal fired hydronic heaters are extremely efficient. Ranking among the lowest emission rates for units tested. Emission rates of auger-fed coal-fired hydronic heaters (0.027g/MJ; **0.06 lbs/MMBtu[heat output basis]**) were consistent with EPA Certified Woodstoves (0.041 g/MJ; **0.10 lbs/MMBtu [heat output basis]**).[3] The DEC is aware that more efficient heating is better for the nonattainment area situation regardless of heating device. Acceptable standards for the installation of coal-fired units should be included within the proposed regulations. There should not only be a standard for the existing units referenced in the regulations but also an achievable emission

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[1] Federal Register, Vol. 80, No.50, Monday, March 16, 2015. Pg. 13672.
[2] Section 7.7.5.1.2 “Device Requirements – wood-fired and coal-fired standards”, Draft Serious SIP.
[3] OMNI-Test Laboratories, Inc. 2011. Measurement of Space-Heating Emissions. Prepared for FNSB. Retrieved from https://cleanairfairbanks.files.wordpress.com/2012/02/omni-space-heating-study-fairbanks-draft-report-rev-4.pdf

rate and standards for new coal-fired units. While there are provisions for the department's approval contingency, it does not provide a target emission rate for respective devices and fuels that are not EPA certified.

Operational Requirements

Issue: The regulation isn't clear as to whether testing can be done with retrofit control devices on non-qualifying solid fuel heating devices to demonstrate qualifying emission rates. Retrofit control devices can reduce pollution emissions significantly. Use of the devices in the nonattainment area should be incentivized.

Request:

- Clarify within the regulations that emissions testing with retrofit controls can be used to qualify the emissions from solid fuel burning devices.
- The use of retrofit control devices, provided significant reductions in emissions were demonstrated, should be incentivized through an exemption for the use of the solid-fuel heating device with retrofit controls during curtailment periods.
- Suggest a lower emission standard which would qualify the use of solid fuel burning devices during curtailment periods.

Background:

The DEC is imposing curtailments for non-exempt devices during emergency episodes. Ideally, if studies associated with retrofit control devices were to demonstrate significant reductions in pollutant emissions, it would seem appropriate to establish emission rates (i.e., 0.10 lbs/MMBtu or less) and allow for the operation of certain devices that have retrofit controls without curtailment during episodes.

Small Area Sources

Issue: Coffee roasters are required to put emission controls on their processes and small area sources are asked to submit information.

Request:

- Remove the provision requiring coffee roasters to have emission controls.
- Establish a significant level for small area sources similar to major source requirements. That is, require emission controls only if the sources are emitting greater than 70 tpy of the nonattainment pollutant or its precursor and are demonstrated as being significant contributors to the nonattainment area.

Background: The department is considering pollution control devices on small area sources, namely coffee roasters. The application of pollution control is requested even though there are no regulations governing coffee roasting as a source of pollution nor is there any justification indicating that coffee roasting has some significant impact on the fine particulate concentration in the area. Under the Clean Air Act and 2016 $PM_{2.5}$ implementation rule, major sources which emit greater than 70 tons per year of fine particulate matter or its precursors have the ability to show insignificance to the area problem through precursor demonstrations and can be exempt from the application of BACT. Not to mention, if a major source curtails their emissions to less than 70 tons per year, the source doesn't have to participate in any control technology assessment or application. Unless there is some reason to believe that 'coffee roasting' by individual roasters are emitting more than 70 tons of $PM_{2.5}$ through their process, then there is no justification for applying control technologies on those sources. The state is currently asking for information from other small area sources, such as charbroilers, incinerators, and waste oil burners. Industrial activities like incinerators and waste oil burners are subject to the state regulations. If the activity is an insignificant unit, or insignificant on an emission rate basis, category basis, or size and production rate basis as described in the state regulations under 18 AAC 50.326 (d) – (g) or the activity is not required to apply for a Construction Permits under 18 AAC 50.302, there should be no requirement for the small commercial activities unless it is known that they are contributing significantly to the problem. Suggested significance should be defined as the impact of the source to $PM_{2.5}$ concentration within the nonattainment area (i.e., 1.5 $\mu g/m^3$) consistent with the 2019 $PM_{2.5}$ precursor demonstration guidance.

2 Best Available Control Technology

The proposed SIP considers BACT for the major sources; however, authorization of the BACT determination is not finalized through the EPA. With an impending date to install BACT four years from the date of reclassification (i.e., June 9, 2021), there doesn't seem to be time for any technological changes to the community of major sources. Although the state is trying to accommodate the deadline for BACT implementation through creative agreements (e.g., Fort Wainwright), the DEC alternatively could provide justification that the implementation of BACT is both technologically and economically infeasible at this time. This option is available to the state through 40 CFR 51.1010 (3). The economically infeasible consideration is discussed later within these comments, however, a technologic infeasibility case could be considered due to the impending deadlines and the actual time it would take to design, build and implement SO_2-BACT for any facility. A cleaner approach to major source BACT would be to determine that SO_2-BACT for the community of major sources is not economically feasible. If that approach is accepted by the EPA, no further consideration would be necessary for BACT.

The ADEC has provided a BACT analysis for the Chena Power Plant (CPP) and other major sources within the nonattainment area. A top-down approach was used for the FNSB stationary sources. Aurora is providing additional information to better characterize the CPP within the context of a BACT analysis. Aurora is providing an updated emission rate, justification for technically infeasible controls for NOx, and updated capital cost for Dry Sorbent Injection (DSI). Lastly, Aurora is providing a justification for the use of a 0.25% coal-sulfur content as opposed to the 0.2% coal-sulfur content proposed by the DEC in the Serious SIP.

SO_2 and NOx emission rate

Issue: The current emission rates used by ADEC within the SIP for Aurora are not representative.

Request: Update the SIP to reflect the most current emission rates of 0.131 lbs-SO_2/MMBtu and 0.359 lbs-NOx/MMBtu as demonstrated by the source test conducted in July of 2019

Background:

Aurora's current emission rates for SO_2 and NOx referenced by the ADEC for the purposes of BACT and probably the emission inventory within this draft SIP are 0.472 lbs-SO_2/MMBtu and 0.437 lbs-NOx/MMBtu. According to the DEC, these emission rates are taken from a 2011 source test; however, those emission rates are inconsistent with the emission rates associated with the 2011 source test which are 0.398 lbs-SO_2/MMBtu and 0.371 lbs-NOx/MMBtu (See Table 1). In October 2018, Aurora conducted a source test to update the SO_2 and NOx emission rates for the CPP. The emission rates derived were 0.258 lbs-SO_2/MMBtu and 0.346 lbs-NOx/MMBtu. This test was invalidated by the DEC.

Table 1: SO_2 and NOx emission rate from November 11, 2019 source testing

Pollutant	Concentration	Conversion Factor	Cd	Fd	O2 %	Emission Rate
Units	(ppm)		(lb/scf)	(scf/MMBtu)	(%)	(lbs/MMBtu)
Sulfur Dioxide	134.3	1.66E-07	7.5E-06	9739	9.5	0.398
Nitrogen Oxide	174.0	1.194E-07	2.1E-05	9739	9.5	0.371

Subsequently, a new source test was conducted with the intent of using the information within the Serious SIP for the BACT analyses, emission inventory, and modeling. Aurora has coordinated with the DEC in order to have a representative source test to better characterize the emissions from the facility. The source test was performed on July 12, 2019 and evaluated SO_2 and NOx emissions while using representative coal. The three year average coal-sulfur content was evaluated for the period July 1, 2016 through June 30, 2019 to determine the representative coal-sulfur content. The coal-sulfur content mean was 0.12%. The source test plan was approved by the department. Representatives from the department were on-site to verify the source test, the coal feed rate, and used the department's portable monitor to measure SO_2, NOx, and other constituents during the source test.

Although the results indicated within this document are preliminary, once the source test report is finalized, it will be submitted to the DEC for approval. As mentioned, the intent of the source test is to better characterize the emissions from the CPP to use in applications within the Serious SIP like the BACT analysis, emission inventory, and modeling. The new emission rate in lbs/MMBtu of the respective pollutants are 0.131 lbs-SO_2/MMBtu and 0.359 lbs-NOx/MMBtu based on EPA Method 19 and are listed in Table 2 below:

Table 2: SO_2 and NOx emission rate from July 12, 2019 source testing

Pollutant	Concentration	Conversion Factor	Cd	Fd	O2 %	Emission Rate
Units	(ppm)		(lb/scf)	(scf/MMBtu)	(%)	(lbs/MMBtu)
Sulfur Dioxide	45	1.66E-07	7.5E-06	9780	9.2	0.131
Nitrogen Oxide	172	1.194E-07	2.1E-05	9780	9.2	0.359

Provided for reference are the emission rates derived for the CPP during the October 27, 2018 source test (See Table 3). This emission rate was used in the Emission Inventory for 2018 from the facility. The test was invalidated due to a lack of representation by the DEC at the source test. The source test utilized EPA methods and an independent 3rd party source testing company to evaluate the flue gas.

Table 3: SO_2 and NOx emission rate from October 27, 2018 source testing

Pollutant	Concentration	Conversion Factor	Cd	Fd	O2 %	Emission Rate
Units	(ppm)		(lb/scf)	(scf/MMBtu)	(%)	(lbs/MMBtu)
Sulfur Dioxide	89.1	1.66E-07	1.5E-06	9776	9.2	0.258
Nitrogen Oxide	166.2	1.194E-07	2.0E-05	9776	9.2	0.346

Technically Infeasible Pollution Control Option

Issue: Selective Catalytic Reduction is not technically feasible at the Chena Power Plant.

Request: Reflect that SCR is not technically feasible within the BACT analysis for the Chena Power Plant.

Background: Based on an engineering study conducted by Stanley Consultants, SCR was determined technically infeasible for reduction of NOx emissions from the industrial coal-fired boilers at the Chena Power Plant.[4] The optimal location of an SCR would be downstream of the baghouse on the common stack. This arrangement would provide for a constant operating gas temperature, reduces issues associated with fouling on the catalyst and locating the SCR downstream of the catalyst would prevent poisoning by the presence of ammonium sulfates created with the injection of ammonia in the flue gas. However, the temperatures of the flue gas after the baghouse are less than adequate. A minimum temperature of 350°F is required for the SCR catalysts to function correctly. The flue gas temperature after the baghouse is approximately 310°F.

Updated Capital Cost for DSI

Issue: Capital cost for DSI as provided to the DEC was determined to be $20,682,000.

Request: Use the capital cost of $20,604,000 for DSI in the BACT analysis to determine a cost effectiveness value.

Background: A refined and final opinion of probable cost is being provided for the CPP DSI which is $20,604,000.[5]

BACT Cost Effectiveness Calculations

Issue: The DEC BACT cost effectiveness values in the draft SIP for the Chena Power Plant are not representative.

Request: Change the section to reflect representative cost effectiveness values based on the representative emission rates outlined below.

[4] Stanley Consultants, Inc. (2019, April). "Best Available Control Technology Analysis – Independent Assessment of Technical Feasibility and Capital Cost". Aurora Energy, LLC.
[5] Ibid.

Background:

BACT cost effectiveness calculations were done by the DEC using established cost estimating procedures. The procedures require that inputs are adjusted to reflect the conditions of the facility assessed. Some of the key inputs identified by the DEC are as follows: the emission rate for SO_2 and NOx were 0.472 lbs-SO_2/MMBtu and 0.437 lbs-NOx/MMBtu, a retrofit factor of 1.5 was used for a difficult retrofit, an interest rate of 5.5%, and equipment life for NOx and SO_2 controls were 20 and 15 years respectively. Using the DEC inputs for wet scrubbers and SDA technologies, the cost effectiveness value and capital costs output are not consistent with the text within the draft SIP. DEC calculated the cost effectiveness for the installation of wet scrubbers and SDA to be $10,620/ton and $11,298/ton. When the DEC inputs were used within the spreadsheets, the cost effectiveness values for the installation of wet scrubbers and SDA were $14,572/ton and $15,726/ton (See Table 4 - values in parentheses) respectively. However, when the emission rate was updated in the spreadsheets to the representative emission rate from the July 12, 2019 source test (0.131 lbs-SO_2/MMBtu), the cost effectiveness value increased to $49,585/ton for wet scrubbers and $53,909/ton for SDA. Using the DEC's spreadsheets for DSI cost effectiveness, Aurora adjusted the capital cost of DSI from $20,682,000 to $20,604,000 based on refined opinion of probable cost and used the updated emission rates referenced in Table 2. The cost effectiveness value for DSI increased from $7,495/ton to $18,007/ton (Table 4).

Table 4: Updated Cost Effectiveness Value based on SO2 and NOx Representative Source Test (7/12/19)

Technology	DEC Cost Effectiveness Value (cost/ton removed)	Capital Cost ($)	Updated Cost Effectiveness Value (cost/ton removed)	Adjusted Capital Cost ($)
Selective Catalytic Reduction	$4,023/ton		Not Technically Feasible	
Selective Non-Catalytic Reduction	$2,227/ton		$2,587/ton	
Wet Scrubbers	$10,620/ton ($14,572/ton)	$57,019,437 ($87,152,852)	$49,585/ton	$82,323,012
Spray Dry Absorbers	$11,298/ton ($15,726/ton)	$51,019,437 ($81,280,628)	$53,909/ton	$77,293,649
Dry Sorbent Injection	$7,495/ton	$20,682,000	$18,007/ton	$20,604,000

Note: Values in parentheses are the output from the cost development methodology used by the DEC with inputs suggested within Section 7.7.8 "Control Strategies" of the draft Serious SIP.

Based on the adjusted values, it is not cost effective to install BACT for SO_2 at the Chena Power Plant.

Sulfur Content of Coal

Issue: Proposed BACT for coal-sulfur content of 0.2% will cut off access to tens of millions of tons of coal for UCM as well as pose a potential threat of fuel supply interruption for the coal fired power plants.

Request: Adopt a new standard of 0.25% based on semi-annual weighted averages of coal-sulfur content in shipments of coal within semi-annual periods corresponding to Facility Operating Report reporting periods.

Background:

The ADEC has proposed that Best Available Control Technology (BACT) for coal burning facilities in the nonattainment area is a coal-sulfur limit of 0.2% sulfur by weight. Usibelli Coal Mine (UCM) is the only source of commercial coal available to the coal-fired facilities within the Fairbanks North Star Borough fine particulate nonattainment area. The mine has limited ability to affect the sulfur content in the coal. There isn't a coal washing or segregating facility associated with UCM which could ensure a consistent coal-sulfur concentration. Current practice for providing low-sulfur coal to customers is identifying sulfur content of the resource through drilling and sampling efforts. However, no matter how much sampling is done, the ability to characterize the sulfur content of the coal actually mined is limited.

Within the millions of tons of coal resources available to UCM, there is a significant amount of coal with higher sulfur content than 0.2%; in fact, any limit proposed to the coal sulfur content is effectively cutting off access to tens of millions of tons of coal resources. As such, AE proposes that the coal-sulfur limit be lowered to 0.25% on an as received basis (wet) as opposed to 0.2% as proposed by ADEC. The increase in coal-sulfur content will help with coal accessibility and availability over the next decade and still provides ADEC with a 37.5% reduction in the potential to emit based from the current limit of 0.4%.

The state was silent on how the measure was to be reported or considered within a regulatory context. The ADEC's standard permit condition for coal fired boilers (Standard Condition XIII) requires that the permittee report sulfur content of each shipment of fuel with the semi-annual Facility Operating Reports. UCM currently provides semi-annual reports to all customers which includes sulfur content of each shipment of coal along with the weighted average coal-sulfur content for the six-month period coinciding with the operating reports' reporting period. UCM and Aurora propose that the standard operating permit condition remain the same and that facilities continue to provide the state with the sulfur content of each shipment of fuel; in addition, the weighted average coal-sulfur content of the shipments received by the facility during the reporting period would be referenced in the operating report.

3 SO_2 Precursor Analysis

Issue: There are inconsistencies in DEC's information with respect to SO_2. The major source contribution to sulfur-based $PM_{2.5}$ from major source SO_2 ground level concentrations have increased from 2008; even though point source SO_2 emissions have decreased while SO_2 emissions from heating oil and total SO_2 emissions have increased.

Requests:

- Change referenced $PM_{2.5}$ significance threshold from 1.3 μg/m^3 to 1.5 μg/m^3 based on the final EPA $PM_{2.5}$ Precursor Demonstration Guidelines (2019).
- Revisit SO_2 Analysis after applying representative emission rates for the Chena Power Plant for SO_2 and NOx (0.131 lbs-SO_2/MMBtu and 0.359 lbs-NOx/MMBtu).
- Clarify discrepancy between the 2008 CALPUFF model output reflecting 22% contribution to ground-level SO_2 from major sources and current CMAQ evaluation reflecting 39% SO_2 contribution from major sources.
- Reconsider SO_2 Precursor Demonstration for Major Source impact using a sensitivity analysis to determine significance.

Background:

The DEC completed an SO_2 Analysis using the 2019 projected baseline inventory and run through CMAQ model. All of the SO_2 emissions were removed from the point source sector in a knock out model run. The meteorology used was from 2008, which is consistent for all of the model runs. The SO_2 from major stationary sources were found to contribute significantly to the $PM_{2.5}$ concentrations at the State

Office Building (SOB) [1.79 µg/m^3] and at the monitoring site adjacent to the Borough building (NCORE) [1.70 µg/m^3] in Fairbanks. The impact of SO_2 from major sources was also determined to be significant at all four monitoring sites (SOB, NCORE, Hurst Road, and NPE) when an alternative approach to estimating the design value contribution from major stationary sources was applied [respectively: 2.66 µg/m^3,2.53 µg/m^3, 1.55 µg/m^3, 1.35 µg/m^3]. The DEC referenced an insignificance threshold of 1.3 µg/m^3 to determine significance; however, final PM2.5 Precursor Demonstration Guidance has changed that threshold to 1.5 µg/m^3.[6]

Regardless of the change in significance value, three of the sites (SOB, NCOR, and Hurst Road) would still be considered significant when the alternative approach to estimating the design value contribution is considered. If the impact of major source SO_2 emissions on $PM_{2.5}$ exceeds 1.5 µg/m^3, then a sensitivity-based analysis may be conducted to show that a reduction of SO_2 emissions in the range of 30 - 70% would only have an insignificant impact on lowering $PM_{2.5}$ concentration. Aurora demonstrated that there was justification to pursue a precursor demonstration using information provided in the moderate area SIP. The major source contribution to $PM_{2.5}$ from SO_2 was determined to be 1.98 µg/m^3 of water-bound ammonium sulfate. The conclusion of the exercise was that a 70% reduction in SO_2 would demonstrate insignificance of the SO_2 contribution from major sources on $PM_{2.5}$ concentration [i.e., 1.45 µg/m^3].[7] It is Aurora's opinion that a successful precursor demonstration may still be possible using a 50% reduction even considering DEC's alternative approach to estimating design value contributions from major source SO_2. However, the DEC has indicated due to sulfate model performance uncertainty and significance of the major source contribution from SO_2 emissions, there is not enough justification to pursue the demonstration.

Aurora has a few concerns with the SO_2 analysis. Probably the most significant is that the contribution of SO_2 at the SOB monitor from major sources increased to 39% from 22% as described in the Moderate Area SIP (2014). CALPUFF modeling showed that the point source SO_2 contribution to the SOB monitoring site was 22% for an episode in 2008. The emission inventory for 2008, 2013, and the projected 2019 show a decreasing trend in SO_2 emissions for point sources (See Table 5). The ratio between SO_2 emissions from oil heating and point sources (Oil Heating SO_2/Point Source SO_2) increases from 2008 to 2019 (projected) from 0.46 to 0.51 for the planning inventory in the NAA (Table 5). This would suggest that the amount of SO_2 emissions from oil increased in relation to the amount of SO_2 emissions from point sources. That fact is counterintuitive to the modeling outputs which indicates SO_2 contribution from point sources increased 18% from 2008 to 2019 at the SOB.

The total SO_2 emissions per day in 2019 is about two times what it was in 2008 and 2013 (See Table 5). The difference is attributed to an increase in Non-Road Mobile sources; in fact, a change in jet fuel between 2013 and 2019 is referenced as the cause of the increase.[8] It would seem that the likelihood for an increased impact at the monitors from SO_2 should have come from this change as opposed to the point sources.

[6] https://www.epa.gov/sites/production/files/2019-05/documents/transmittal_memo_and_pm25_precursor_demo_guidance_5_30_19.pdf
[7] Memo. Ramboll. "Summary of issues related to SO_2 precursor demonstation for Fairbanks". 2018.
[8] Section 7.6.3.2 "2019 Projected Baseline Emission Inventory", Draft Serious SIP.

Table 5: Baseline Episode Average Daily SO_2 Emissions (tons/day) by Source Sector

Source Sector	Modeling Inventory Grid 3 Domain			Planning Inventory NA Area		
	2008	2013	2019 (projected)	2008	2013	2019 (projected)
Point Sources	8.380	7.40	7.32	8.167	7.22	7.13
Area, Space Heating, Oil	4.121	3.68	3.90	3.719	3.42	3.61
Total	12.875	12.65	25.58	12.155	11.92	22.36

Note: 2008 data from Moderate Area SIP (Table 5.6-7); 2013 & 2019 data from draft SIP, Tables 7.6-10 & 7.6-12, respectively.

The increase in point source contribution of SO_2 at the monitoring sites is, therefore, perplexing. Aurora also believes that point source emission of SO_2 in the inventories may be inflated due to the emission factor used to determine Aurora's SO2 emissions (and NOx emissions). Within the BACT section of the draft SIP, an emission factor for SO_2 was referenced as being 0.472 lbs-SO_2/MMBtu. A recent source test conducted on July 12, 2019 at the Chena Power Plant was arranged specifically to better characterize the emission rates for SO_2 and NOx from the plant. The test plan was approved by the state with additional scrutiny due to its intended use. The test demonstrated an emission factor of 0.131 lbs-SO_2/MMBtu. This value is a preliminary emission rate. The final report will be provided to the DEC so that, when approved, the new emission rate would be updated in the state's databases and worksheets for the final submittal of the Serious Area SIP to the EPA.

Aurora would also like the state to clarify the discrepancy between the 2008 CALPUFF modeling, which showed a major source SO_2 contribution of 22% at the SOB monitoring site, in relation to the recent evaluation referenced under the SO_2 Analysis (Section 7.8.12.5) where major source SO_2 contribution to the SOB was 39%. Aurora would like the DEC to reconsider an SO_2 precursor demonstration for major source contribution to $PM_{2.5}$ concentration. Aurora believes a successful demonstration could be done using the provisions of a sensitivity analysis as described in the 2019 $PM_{2.5}$ Precursor Demonstration Guidance.

4 Major Source Economic Infeasibility Justification

Issue: The DEC has the option to demonstrate the economic infeasibility of SO_2 BACT for major sources within the nonattainment area under 40 CFR 51.1010 (3) based on cost effectiveness. The most cost effective value for operating BACT controls on the community of major sources to remove 1 $\mu g/m^3$ of $PM_{2.5}$ is $9,794,799 per year [See Table 7b].

Request:

- Define cost effectiveness as cost per 1 $\mu g/m^3$ of $PM_{2.5}$ for this exercise.
- Derive a cost per ton removed for each major source in the nonattainment area by adjusting operational load to represent actual SO_2 emissions in the spreadsheets for each facility provided within the appendices of the "Control Strategies" section of the draft serious SIP.
- Evaluate the cumulative annualized cost incurred by the community of major sources within the nonattainment area based on potential tons removed from implementing SO_2 BACT using actual emissions (instead of PTE).

- Correlate annualized cost of SO_2 BACT controls with results from the SO_2 Analysis section of the draft SIP (Section 7.8.12.5) to derive a cost per µg/m^3 mitigated from applying SO_2 control technologies.

Background:

Major stationary sources are a subgroup of emission sources that are given special consideration under nonattainment area provisions. Point sources with emissions greater than 70 tons per year of $PM_{2.5}$ or any individual precursor (NOx, SO_2, NH_3, VOCs) are evaluated for appropriate control. NOx and SO_2 were addressed on an emission unit specific basis in DEC's Best Available Control Technologies (BACT) determinations. The DEC's evaluation considered technical feasibility and estimates of emissions reductions to meet a defined emission limit. Operations at the facility's potentials to emit is used for the purpose of identifying a cost effectiveness for each technology in cost per ton removed.

The BACT analyses evaluate pollution control independent of the nonattainment area problem; it is simply triggered as a condition of an area defined as being in serious nonattainment of a pollutant standard. As described in the 2016 $PM_{2.5}$ Implementation Rule, the state can provide either a technologic or an economic infeasibility demonstration for control measures.[9] The argument must illustrate it is not technologically or economically feasible to implement the control measure by the end of the tenth calendar year (i.e., December 31, 2019 for the FNSB NAA) following the effective date of the designation of the area. Aurora believes that there is enough evidence to substantiate that SO_2 controls on the community of major sources is economically infeasible.

<u>Economic Infeasibility Justification</u>

The DEC has determined BACT is comprised of sulfur controls for major stationary sources. The DEC has also determined that sulfur controls are economically infeasible for one major source, silent on infeasibility for another, and partially economically infeasible for a couple of major sources within the NAA.[10] Per regulation, DEC has the authority to demonstrate that any measure identified is economically infeasible.[11] It is within the DEC's authority to determine that BACT for sulfur control is economically infeasible for the community of major sources in the NAA based on cost effectiveness.[12] If cost effectiveness is defined as cost per µg/m^3 removed, there is a clear justification to eliminate sulfur control measures from the community of major sources. The most cost effective value for operating BACT controls on the community of major sources to remove 1 µg/m^3 of $PM_{2.5}$ is $9,794,799 per year [See Table 7b].

<u>Annualized Cost of BACT Implementation</u>

The DEC derived cost effectiveness value in cost per ton removed is established through the implementation of the BACT analysis. The DEC preferred BACT controls and cost effectiveness value are referenced in Section 7.7.8 of the SIP.[13] Dry Sorbent Injection (DSI) is selected for the coal fired boilers with an 80% reduction in SO_2 and ULSD is suggested for GVEA's North Pole Plant and Zehnder

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[9] 40 CFR 51.1010 (3)
[10] Section 7.7.8 of the draft Serious SIP
[11] 40 CFR 51.1010 (3)
[12] 40 CFR 51.1010 (3)(ii)
[13] Appendix III.D.7.07 Control Strategies: https://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-serious-sip/

Facility with a 99.7% removal rate for SO_2. Based on the Potential to Emit (PTE) of each facility, the state derives a cost effectiveness value for the sources.

Annualized cost to implement BACT for the community of major sources are based on operating scenarios for both PTE and actual emissions (2013) [14] from the facilities. The results are illustrated in Table 6a and 6b. The cost effectiveness value (cost/ton removed) is multiplied by the amount of pollution removed (tons) to derive an annual cost for BACT for each facility. The total annualized cost is the sum of the cumulative annual operating cost for the controls on all the major sources in the NAA. The annualized costs do not include the cost of fuel switching for smaller diesel engines, backup generators and boilers that are found on the campuses of certain facilities (e.g., UAF, FWA). The total annualized BACT implementation cost to operate at the PTEs is $49,296,062; annualized cost considering actual emissions is $20,843,332 (See Tables below).

Table 6a: BACT Annualized Costs Based on Potential To Emit

Facility	BACT (SO_2 Control)	SO_2 Reduction	SO_2 Emissions PTE[3]	SO_2 Reduction[3]	Cost/ton removed [2,3]	Annualized Cost
Units		(%)	(tpy)	(tpy)	($)	($)
Chena Power Plant	DSI	80	1,004.0	803.0	$ 7,495	$ 6,018,485
FWA	DSI	80	1,168.5	934.8	$ 10,329	$ 9,655,331
NPP-EU1	ULSD	99.7	1,486.4	1,482.0	$ 9,139	$ 13,543,998
NPP-EU2	ULSD	99.7	1,356.1	1,352.0	$ 9,233	$ 12,483,016
UAF	DSI	80	242.5	194.0	$ 11,578	$ 2,246,132
Zender	ULSD	99.7	598.6	597.0	$ 8,960	$ 5,349,120
Notes: See Below.					Total Annualized Cost	$ 49,296,082

Table 6b: BACT Annualized Costs Based on Actual Emissions

Facility	BACT (SO_2 Control)	SO_2 Reduction	SO_2 Emissions (Actual)[1,3]	SO_2 Reduction	Cost/ton removed[4]	Annualized Cost
Units		(%)	(tpy)	(tpy)	($)	($)
Chena Power Plant	DSI	80	711.8	569.4	$ 8,960	$ 5,101,824
FWA	DSI	80	766.5	613.2	$ 11,235	$ 6,889,302
NPP-EU1	ULSD	99.7	142.3	141.9	$ 12,169	$ 1,726,454
NPP-EU2	ULSD	99.7	422.3	421.0	$ 9,453	$ 3,980,026
UAF	DSI	80	219.0	175.2	$ 11,578	$ 2,028,466
Zender	ULSD	99.7	73.0	72.8	$ 15,351	$ 1,117,261
Notes:					Total Annualized Cost	$ 20,843,332

1 - Table 7.6-9 "2013 SO2 Episodic vs. Annual Average Point Source Emissions (tons/day)"
2 - Sectoin 7.7.8 of SIP
3 - BACT Spreadsheets (May 2019) in SIP for Listed Facilities; adjusted AE emission factor of 0.472 lbs-SO2/MMBtu referenced in BACT Section of SIP.
4 - Cost/ton removed after adjusting operational load in BACT Spreadsheets (May 2019) to reflect actual emissions; AE emission factor of 0.472 lbs-SO_2/MMBtu

Major Source SO_2 Control Cost Effectiveness: Cost per $\mu g/m^3$ $PM_{2.5}$ Removed

The DEC provided an SO_2 analysis using the 2019 projected baseline inventory. [15] The DEC determined that major stationary sources were found to contribute significantly to $PM_{2.5}$ concentrations at the State Office Building (SOB) and the monitor adjacent to the Borough building (NCORE) in downtown Fairbanks. The impact at the monitors were 1.79 $\mu g/m^3$ and 1.70 $\mu g/m^3$ respectively.[16] The impact at the Hurst Road and North Pole Elementary (NPE) monitors were 0.04 $\mu g/m^3$ and 0.10 $\mu g/m^3$ respectively.

Assuming that an 80% removal of the point source emissions of SO_2 would translate to an 80% reduction to the impact from major sources of sulfur-based $PM_{2.5}$ at the monitors, the amount of $PM_{2.5}$ reduced at the SOB, NCORE, Hurst Road, and NPE monitors would be 1.43 $\mu g/m^3$, 1.36 $\mu g/m^3$, 0.03 $\mu g/m^3$, and 0.08 $\mu g/m^3$ respectively. Based on the total annualized cost for BACT controls using actual emissions ($20,843,332) the cost effectiveness value in cost per $\mu g/m^3$ of $PM_{2.5}$ removed is at the best, $14,555,400 per $\mu g/m^3$ removed and at the worst $651,354,137 per $\mu g/m^3$ removed (Table 7a). If the alternative

[14] Table 7.6-9 "2013 SO2 Episodic vs. Annual Average Point Source Emission (tons/day)"[Draft Serious SIP]ADEC
[15] Section 7.8.12.5 of the draft Serious SIP
[16] Table 7.8-26. "Design value contribution from major stationary source SO_2".Draft Serious SIP.

approach to the SO_2 design value contribution from major sources is considered then the cost effectiveness at best is \$9,794,799 per µg/m^3 and at worst is \$19,299,382 per µg/m^3 (Table 7b).

Ironically, the cost per µg/m^3 removed is less at the SOB and NCORE sites where the projected design value is in compliance with the standard. The projected design value provided by the DEC for 2019 meet attainment at the SOB and NCORE sites which are of 29.72 µg/m^3 and 29.01 µg/m^3 respectively[17]; the attainment standard is 35 µg/m^3. The 2019 design values at the Hurst Road and NPE monitors were 104.81 µg/m^3 and 36.48 µg/m^3, both clearly above the attainment standard of 35 µg/m^3. The impact from the major sources is less significant at the sites where the 2019 projected design value violates the standard.

Table 7a: Cost Effectiveness Based on Design Value Contribution SO_2 from Major Stationary Sources

Site	Design Value Base Year 2013[1]	Projeced Design Value Year 2019[1]	Major Source Sulfur-Based Particulate Contribution[2]	BACT Reduction (80% of Direct Emissions)	BACT Reduction / Design Value 2019	Annualized BACT Cost per ug/m^3 removed
Units	(ug/m^3)	(ug/m^3)	(ug/m^3)	(ug/m^3)	(%)	(\$)
State Office Building (SOB)	38.93	29.72	1.79	1.43	4.8%	\$ 14,555,400
Fairbanks Borough Building (N	37.96	29.01	1.70	1.36	4.7%	\$ 15,325,980
Hurst Road	131.63	104.81	0.04	0.03	0.0%	\$ 651,354,137
North Pole Elementary (NPE)	45.3	36.48	0.10	0.08	0.2%	\$ 260,541,655

Notes:
1 - Table 7.8-29 of Draft Serious SIP
2 - Table 7.8-26 of Draft Serious SIP

Table 7b: Cost Effectiveness Based on Alternative Approach to Design Value Contribution SO_2 from Major Stationary Sources

Site	Design Value Base Year 2013[1]	Projeced Design Value Year 2019[1]	Major Source Sulfur-Based Particulate Contribution[2]	BACT Reduction (80% of Direct Emissions)	BACT Reduction/Design Value 2019 x 100	Annualized BACT Cost per ug/m^3 removed
Units	(ug/m^3)	(ug/m^3)	(ug/m^3)	(ug/m^3)	(%)	(\$)
State Office Building (SOB)	38.93	29.72	2.66	2.13	7.2%	\$ 9,794,799
Fairbanks Borough Building (N	37.96	29.01	2.53	2.02	7.0%	\$ 10,298,089
Hurst Road	131.63	104.81	1.55	1.24	1.2%	\$ 16,809,139
North Pole Elementary (NPE)	45.3	36.48	1.35	1.08	3.0%	\$ 19,299,382

Notes:
1 - Table 7.8-29 of Draft Serious SIP
2 - Table 7.8-27 of Draft Serious SIP

Fairbanks exceeds the fine particulate matter standard during winter months.[18] Control technology application on major stationary sources is permanent and transcends seasons. BACT for sulfur control on major sources is an annual solution to a wintertime problem. The application of SO_2 BACT is arguably an impractical effort. Where the pollutant concentration is either achieving or almost achieving the standard, the projected impact removed by application of BACT on the major sources is about 7% of the concentration. Since the standard is attained, removing 7% more of sulfur-based $PM_{2.5}$ for costs upward of \$10 million dollars per µg/m^3 seems impractical. There is a mechanism allotted within the 2016 $PM_{2.5}$ Implementation Rule for the DEC to provide a detailed written justification for eliminating, from further consideration, potential control measures for SO_2 on the community of major stationary sources based on cost ineffectiveness.

As such, Aurora supports an economic infeasibility determination for the application of BACT on all major stationary sources within the nonattainment area.

[17] Table 7.8-29. "2019 FDV for Projected Baseline and Control Scenario Calculated against a 2013 Base year".
[18] Section 7.8.6 of the Draft Serious SIP

5 $PM_{2.5}$ Emission Reduction Credits

Issue: Currently there are no provisions for the FNSB NAA within the regulations that establish emission reduction credits.

Request: Include provisions in the Serious SIP for establishing $PM_{2.5}$ emission reduction credits per 40 CFR 51 Appendix S.

Background:

Aurora Energy requests that the SIP include provisions for establishing PM2.5 emission reduction credits, as provided in 40 CFR 51 Appendix S. The SIP should recognize that the most fertile area for establishing further emission reduction credits involves reducing emissions from wood-fired residential heaters – stoves and fireplaces. The approach to accounting for dried wood emissions should consider enhanced wood-moisture reduction through a process such as kiln drying, to levels as low as 15 percent (dry wood basis) beyond the 20 percent levels in the proposed SIP and allow those lower emissions to be applied as emission reduction credits for potential future development within the Non-Attainment Area. The approach also lessens the level of involvement of agency oversight of the individual components of the SIP that are related to residential wood combustion. Residential wood combustion is an ingrained cultural component of life in Fairbanks, and the proposed enhanced drying option is likely to be well supported by members of the community. We urge consideration of this approach that will both clean the air and provide some potential for emissions increases, through offsets developed under this proposal, to further strengthen the economic viability of the Fairbanks North Star Borough community.

6 Conclusion

In summary, there are several elements to the SIP that Aurora is addressing as a part of the public comment. The DEC has an incredible task which is being addressed to the extent possible with the time and resources available. Below are summaries of the key points Aurora addressed within the comments:

- BACT requirement for coal facilities to meet coal-sulfur content of 0.2% is being contested. Auroras requests a modified BACT requirement to 0.25% coal-sulfur (as received) evaluated on a six-month weighted average using UCM analyses for each shipment.
- SO_2 and NOx emission rates being used for Aurora within the SIP are not accurate representation of the facilities emission rates. Suggest using newly established rates derived through representative source testing with representative coal.
- Additional information is provided to support technologic infeasibility of SCR, a change in the capital cost for DSI, and emission rate changes for the determination of cost effectiveness within the context of the BACT analyses.
- Aurora supports an economic infeasibility determination for the community of major sources based on the cost ineffectiveness of sulfur control technology in removing 1 $\mu g/m^3$ of sulfur-based $PM_{2.5}$ from major source SO_2 contribution.
- Aurora requests that the SIP include provisions for establishing $PM_{2.5}$ emission reduction credits, as provided in 40 CFR 51 Appendix S.
- One of the key parts to the future of the nonattainment area is the 5% reduction plan. The elements within this plan, which is anticipated for submittal at the end of 2020, have not been communicated to the community or industry. It is the opinion of Aurora that communication with the community about the elements within the 5% reduction plan is warranted and necessary.

- Solid fuel burning devices are not treated equally within the Serious Area SIP. A proposition for a common emission standard for those units that do not have EPA certification or standard to meet is encouraged. Those units with EPA standards should be allowed to operate within the NAA. Also, inclusion of emission standards and criteria for coal-fired home heating devices within the regulation is encouraged.
- Retrofit control devices should be encouraged for use to meet emission standards as necessary.
- The departments' imposition of control technologies on small sources, such as coffee roasters, is not supported. Major sources are able to take operational limits to reduce emissions to less than 70 tons per year to avoid pollution control. Small commercial sources shouldn't be subject to pollution controls unless there is evidence that their emissions are significant.

Enclosure:

Stanley Consultants, Inc. (2019, April). "Best Available Control Technology Analysis – Independent Assessment of Technical Feasibility and Capital Cost". Aurora Energy, LLC.

Best Available Control Technology Analysis

Independent Assessment of Technical Feasibility and Capital Cost

Chena Power Plant
Aurora Energy, LLC
Fairbanks, Alaska

Final
April 2, 2019

Stanley Consultants INC.
A Stanley Group Company
Engineering, Environmental and Construction Services - Worldwide

April 2, 2019

Mr. David Fish
100 Cushman Street
Suite 210
Fairbanks, AK 99701

Dear Dave:

Stanley Consultants is pleased to provide you with the final version of the Independent Assessment of Technical Feasibility and Capital Cost in support of your Best Available Control Technology Analysis. We greatly appreciate the opportunity to assist Aurora Energy in this effort and we look forward to working with you again soon.

Respectfully submitted,

Stanley Consultants, Inc.

Prepared by Jason Smith

Approved by
John P. Solan

STATE OF ALASKA
49 TH
JOHN P. SOLAN
No. ME14412
4/2/19
REGISTERED PROFESSIONAL ENGINEER

I hereby certify that this engineering document was prepared by me or under my direct personal supervision and that I am a duly licensed Professional Engineer under the laws of the State of Alaska.

My license renewal date is December 31, 2019.
Pages or sheets covered by this seal: Entire Report

Table of Contents

APPENDICES

Section 1

Introduction

This report documents the results of an independent engineering assessment of the technical feasibility and probable capital costs for emissions control retrofits at the Chena Power Plant in Fairbanks, Alaska. The report is intended to supplement the information previously provided by Aurora Energy in the Best Available Control Technology (BACT) Analysis Report, including any revisions or addendums thereto. It also incorporates some of the conclusions reached by the Alaska Department of Environmental Conservation (ADEC) in their Preliminary Best Available Control Technology Determination.

Background

The US Environmental Protection Agency (EPA) has recently reclassified portions of the Fairbanks North Star Borough as a Serious PM 2.5 Non-Attainment Area. This reclassification triggers a requirement that all major sources within the non-attainment area perform a BACT analysis for particulate emissions and the emissions of any precursor pollutants. In response to this requirement Aurora Energy submitted the required BACT Analysis to ADEC in March of 2017. An addendum to the report was submitted in December of that year.

After reviewing the data and conclusions presented in the BACT Analysis, ADEC conducted their own analysis and presented the results as a Preliminary BACT Determination in March 2018. The ADEC report documented several conclusions that differed from those presented in the BACT report submitted by Aurora Energy.

Project Scope

Given the disparity in the results of the analyses, Aurora Energy hired Stanley Consultants to review the technical feasibility of control technologies for two specific precursor pollutants; Nitrogen Oxides (NO_x) and Sulfur Oxides (SO_x). In this report these pollutants may also be referred to as Nitrogen Oxide (NO) and Sulfur Dioxide (SO_2) as these are the most common forms of the nitrogen and sulfur pollutants.

Aurora Energy also requested that Stanley Consultants develop a site-specific, third-party estimate of the costs to install and operate technically feasible SO_2 emissions control equipment on the four operating boilers at the Chena Power Plant. This effort will include the development of a capital cost estimate for the identified systems, sorbent consumption rate estimates, and an estimated cost for the purchase and delivery of sorbent to site. Once these costs have been developed, Aurora Energy and their environmental consultants, Environmental Resources Management (ERM), will incorporate the estimated costs into a calculation to determine the cost effectiveness of the emissions control equipment on a basis of Dollars/Ton of SO_2 removed.

Section 2

Discussion of NO_x Control Options

The original BACT Analysis developed by ERM provided a comprehensive review of the various technologies currently available to control NO_x emissions. It also identified if each technology was technically feasible or infeasible based on the specific application at the Chena Plant. The report concluded that the only technically feasible NO_x reduction technologies were Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR). Similar conclusions regarding the technical feasibility were reached by ADEC in the Preliminary BACT determination.

Stanley Consultants has reviewed the information provided in both documents. While we are in general agreement, there are technical limitations relating to the application of SCR and SNCR technology that were not adequately addressed in either document.

Selective Catalytic Reduction

Both the ENR BACT Analysis and the Preliminary BACT Determination correctly determine that SCR technology has been successfully utilized to reduce the emissions of nitrogen oxides on industrial coal fired boilers. Both documents detail the mechanism by which the oxides are removed from the flue gas stream and the both correctly note that the chemical reaction is highly dependent on the flue gas temperature. Neither report, however, mentions the actual flue gas conditions at the Chena Plant, nor do they mention where a SCR is typically located with respect to the boiler outlet and the stack. A flue gas temperature is provided in the ADEC SCR Economic Analysis Spreadsheet (https://dec.alaska.gov/media/7381/chena-scr-economic-analysis-adec.xlsm). This spreadsheet uses a flue gas temperature of 310 °F based on information collected during a 2016 source test at the Chena Plant. This data, however, is only used to calculate the Volumetric Flue Gas Flow Rate. There is no check in the ADEC SCR Economic Analysis spreadsheet to determine if the subject emission source flue gas temperature is within a typical operating temperature range for commercially available catalyst.

Modern SCR systems for industrial boiler applications like the Chena Plant are generally located downstream of the flue gas particulate filter. This position in the flue gas system has several advantages:

- This arrangement allows a constant operating gas temperature throughout the boiler load range.
- Locating the SCR downstream of a baghouse significantly reduces issues associated with ash fouling of the catalyst blocks.
- Locating the SCR downstream of sulfur emissions control equipment will prevent the catalyst from being poisoned by the presence of ammonium sulfates which are formed when ammonia is injected into the flue gas stream in the presence of sulfur.

The Chena Plant currently utilizes a single baghouse to filter particulate from the flue gas streams of all four boilers. The optimal location for any future SCR would therefore be on the common flue gas duct immediately downstream of the existing baghouse.

The boilers at the Chena Plant are currently configured with an integral economizer attached directly to the exhaust flange of each boiler. The purpose of this economizer is to utilize waste heat in the flue gas to preheat water entering the boiler drum. This results in a significant reduction in flue gas temperature across the economizer. The 2016 source test data used by ADEC in their economic analysis indicated that typical full-load flue gas temperatures at the stack was approximately 310 °F. Stanley Consultants provided this information, along with other information relating to the flue gas system configuration, to a systems vendor BACT Process Systems for their review and input. BACT Process Systems was contacted as they had recent experience in the supply and installation of emissions control equipment (including a Dry Sorbent Injection System and SCR) at nearby Eielson Air Force Base (EAFB). The EAFB facility burns the same coal as the Chena plant in boilers of similar design. The response from BACT, based on information collected from one of their current catalyst suppliers, indicated that current SCR catalysts require a minimum of 350 °F to function effectively. This statement was also verified by a second SCR vendor. A representative of Fuel Tech, Inc. indicated that temperatures below 400 °F can significantly increase the required amount of catalyst. The representative also confirmed that the minimum flue gas temperature is between 350 °F and 365 °F. Information provided by both vendors can be found in Appendix A.

Other SCR configurations are utilized to allow the installation of an SCR into an existing flue gas system. The configuration that is most applicable to this scenario would be one that was recently utilized at Eielson Air Force Base in conjunction with the installation of the replacement boilers for Units 5 and 6. The design at Eielson relies on two separate economizers. The first economizer is integral to the boiler and is used to reduce the temperature of the flue gas leaving the boiler to approximately 500 °F. The flue gas is then treated with sodium bicarbonate to reduce sulfur emissions before it passes through the baghouse and the SCR. The second economizer is located after the SCR and is used to reduce the flue gas temperature to approximately 300 to 350 °F. This configuration works well for the Eielson facility because each flue gas system is separate from the other boilers and the equipment (boiler, sorbent injection, baghouse, SCR, and economizers) are in close proximity to each other. This configuration would not be possible at the Chena Plant due to the existing boiler enclosure building and the existing common flue duct tying the boilers together into the baghouse and the large distances between the boilers and the baghouse.

Given the constraints identified above, Stanley Consultants concludes that Selective Catalytic Reduction is not technically feasible at the Chena Plant. This is contrary to the conclusions reached by both ERM and ADEC.

Selective Non-Catalytic Reduction

Stanley Consultants has reviewed the information relating to SNCR systems in both the ERM and ADEC documents and is in general agreement with the technical information provided in each. Information relating to SNCRs was also solicited from BACT Process Systems. Their response, included as Appendix B, also supports the conclusion that SNCR systems appear to be technically feasible.

The actual performance of a SNCR system can vary significantly based on the actual flue gas flow, the flue gas conditions and constituents emitted from each boiler. Given the boiler's size, their stoker and moving grate combustion method, and their limited back-pass configuration, Stanley Consultants would recommend retaining a SNCR System and Equipment Supplier to perform an engineering study prior to the finalization of any BACT determination, revising the air permit to restrict NO_x emissions, or concluding that SNCR technology is a technically feasible solution. The study would generally include steps (a) through (d) as identified in Appendix B. The steps consist of an assessment of existing conditions and fuels and the development of a computational model of the boiler. The results of the study can be used to optimize furnace combustion conditions, select the preferred reagent (ammonia versus urea), locate reagent injection nozzles, and predict reagent consumption and system performance for inputs to a financial model and capital outlay of SNCR for comparative efforts to the age, condition, and expected longevity of the existing boilers.

Section 3

Discussion of SO_x Control Options

The original ERM BACT Analysis provided a limited discussion of Flue Gas Desulfurization (FGD) that focused generally on wet or dry type systems. While there is only one Wet FGD technology, there are several technologies that are considered to be “dry” or “semi-dry” FGD processes. Each of these technologies have benefits and limitations that should be individually considered to determine technical feasibility, on a site-specific basis. Additional information on specific types of dry FGD equipment was provided in December of 2017 as an addendum to the original report. This addendum discussed the technical merits of Spray Dryer/Absorbers (SDA) and Dry Sorbent Injection (DSI) in additional detail. The results of the technical evaluation presented in both the primary report and the addendum concluded that all three of the evaluated technologies (Wet FGD, SDA, and DSI) were technically feasible. The subsequent economic evaluation, however, eliminated each technology due to their evaluated cost effectiveness. Each technology was estimated to have costs that exceeded $20,000 per ton of SO_2 captured.

The ADEC BACT Determination was in general agreement with the rationale used by ERM to determine the technical feasibility of the three FGD systems evaluated. It also reached the same conclusions regarding the cost effectiveness of the Wet FGD and SDA technologies. Both systems were far too expensive when compared to the predicted reduction in emissions. The ADEC calculation of cost effectiveness for a DSI system, however, resulted in a significantly lower cost per ton of SO_2 removed. The conclusion reached by ADEC in their BACT Determination was that a DSI system was both technically feasible and cost effective, therefore DSI qualified as BACT.

Stanley Consultants was asked to review the BACT Analysis and BACT Determination and to provide technical input where necessary. We were also asked to review the economic analyses provided in both documents and to develop an independent estimate of capital (initial investment), operating, and maintenance (annualized) costs for a DSI system. Finally, we were asked to provide technical and economic information for a Circulating Dry Scrubber (CDS) FGD system. This was based on a recent determination by ADEC that the CDS technology has been successfully implemented as a FGD device in other industrial coal boilers, and therefore it must be included in the BACT analysis.

Wet Flue Gas Desulfurization and Spray Dryer Absorbers

Stanley Consultants reviewed both the BACT Analysis and the BACT Determination and agrees with the conclusion that the Wet FGD or SDA controls will not be cost effective and therefore are not BACT.

Circulating Dry Scrubbing

As previously stated, Aurora Energy recently received a request from ADEC to include Circulating Dry Scrubbing as a commercially available control technology in the BACT Analysis. The information in this section is structured to compare the CDS technology to a SDA system. The chemical process by which the sulfur is removed from the flue gas is the same in both technologies, however, there are several differences between the two systems that have significant impacts on the technical viability and cost effectiveness of each system.

Both the CDS and SDA technologies, for industrial coal fired applications, employ an alkaline reagent of calcium hydroxide, hydrated quicklime, and fly ash, which is collected from the combustion process. The calcium hydroxide reacts with Sulfur ioxide (SO_2) and sulfur trioxide (SO_3) of the flue gas to form calcium sulfite and calcium sulfate. The calcium sulfite and calcium sulfate, unreacted calcium hydroxide, and fly ash are collected downstream of the acid gas scrubbing process by a baghouse, and a considerable portion is “recycled,” back to the scrubber to offset reagent costs by utilizing available unreacted alkalinity of the fly ash. The fly ash particles also serve to increase the available surface area for reactions to occur. Both processes also depend on the addition of water to humidify the flue gas. In general, the greater the humidification, the lower the alkalinity stoichiometry, which reduces reagent consumption. To prevent corrosion downstream of these scrubbers and promote the longevity of downstream equipment (namely fluework, particulate collection, and stack), the humidification is limited to operating above the saturation temperature, referred to as the approach temperature.

The method by which the flue gas stream is humidified is an area where the SDA and CDS scrubbing processes diverge.

In the SDA process, water for humidification is delivered as a portion of the lime and ash constituents. The water, lime, and ash slurries are pumped through recirculation loops and fed to an atomization feed system. The slurry that is fed to the atomizer is then atomized into small droplets which are dispersed in a passing flue gas stream inside an absorber or scrubber vessel. Once dispersed in the flue gas, a chemical reaction occurs, and the gas stream is scrubbed of the SO_2 and SO_3 pollutants. Since the slurry reagent is hydraulically conveyed by pumping, the SDA process can sometimes leverage existing infrastructure such as the particulate collection equipment. The ability to integrate a SDA system into an existing flue gas system limits the capital outlay necessary for a targeted level of compliance. The potential to leverage existing infrastructure is dependent on numerous factors such as existing equipment layout and condition, site spatial limitations, and original design parameters of the existing particulate collection equipment.

The humidification of the flue gas stream for a CDS scrubbing process is essentially decoupled from the hydrated lime and ash constituents. Water for gas humidification is mechanically atomized into the passing flue gas stream and the dry alkaline products are conveyed to the CDS vessel using air slide conveyors. Air slide conveyors utilize an air permeable fabric, which is stretched across a rectangular enclosure flow path, to aerate particulate material, and allow the force of gravity to covey the material down the sloped surface. The alkaline material and water injection (humidification) typically occurs after a venturi assembly that increases the velocity of the passing flue gas stream to establish a fluidized bed of alkaline material. As the flue gas passes through the bed of alkaline material, it is scrubbed of the SO_2 and SO_3. The use of air slides to convey the fly ash from the particulate collection device (typically a baghouse) back to the scrubber necessitates that the particulate collector (baghouse) be placed at higher elevations. This will ensure that the proper slope is established between the collector and the injection point on the absorber tower. It is technically challenging to take an existing particulate collector and elevate it, so CDS technologies are typically purchased with an absorber vessel, air slides, particulate collection device, and waste ash systems. This allows the integration of the required elevation differences and the steel and foundations necessary to accommodate the higher elevation construct. Due to the additional equipment, steel, and deep foundations necessary, these factors typically increase the capital outlay for a CDS technology.

Additional information on both SDA and CDS technology can be found in Chapter 34 of STEAM, Its Generation and Use, 42nd Edition, Babcock and Wilcox, Inc. Reference Figure 10 on Page 34-15 for an illustration of a typical SDA installation and Figure 17 on Page 34-21 for an illustration of a typical CDS installation.

The information above indicates that CDS and SDA technologies are similar in their nature and operation. However, the installation of a CDS frequently requires the installation of a new particulate collector, where the SDA system may not. The CDS equipment itself, along with the additional equipment needed for proper operation, will result in an initial (capital) cost that is significantly higher than an equivalent SDA system. Given that the ADEC BACT Determination has already established that a SDA system is not cost effective (Table 4-3, Page 12), it can therefore be concluded that the CDS system is also not cost effective, and therefore is not BACT.

Dry Sorbent Injection (DSI)

Stanley Consultants has reviewed the technical information provided in both the BACT Analysis and the BACT Determination relating to DSI systems. Based on our experience with DSI applications, we agree that DSI controls are technically feasible. Given the discrepancy in the evaluated cost effectiveness between the two reports, Aurora Energy retained Stanley Consultants to provide an independent estimation of the actual capital investment and annualized costs for a dry sorbent installation at the Chena Plant. The primary goal of this effort was to develop a site-specific cost estimate by identifying the costs to procure and install the specific equipment and components that are required for the Chena plant. Reference Section 4 of this report for additional information.

Section 4

Project Cost Estimates

Disclaimer

The information presented in this section was developed using a methodology intended to produce a result that represented the lowest reasonable cost for the project. The cost information provided herein is not a realistic estimate of actual project costs and should not be utilized for project budgeting purposes or other financial predictions.

Design Basis

The following data and assumptions were utilized to identify the system performance requirements and scope of supply for both the DSI equipment vendor and the construction contractor. Equipment and piping (internal to silo skirts and sorbent preparation building) costs for the DSI systems were developed by BACT Process Systems, Inc. BACT supplied the DSI system that was recently installed at Eielson AFB, and therefore was already familiar with this type of application. Additional information relating to the BACT scope of supply can be found in Appendix C. Balance of Plant (BOP) piping, electrical, and foundations were estimated by Stanley Consultants, as described below.

Boiler Performance and Flue Gas

The coal used at both the Eielson AFB and Chena Plants is supplied from the Usibelli Coal Mine in Healy, Alaska. Boiler heat input, flue gas flows, and uncontrolled SO_2 emissions rates for the Chena Plant were obtained from previous flue gas studies. The available coal data and the information provided in the studies was utilized to determine storage needs, equipment sizes, and required sorbent feed rates.

Dry Sorbent Unloading, Storage, Preparation, and Injection System

The BACT proposal includes the following equipment:

- Sorbent unloading equipment suitable for transporting sodium bicarbonate from a railcar to a bulk storage silo. This equipment includes unloading blowers, coolers, piping and piping components.

- Two bulk storage silos with a total storage capacity that are sufficient for three months of continuous full load operation.

- Sorbent transfer equipment for moving the sorbent from the bulk storage silos to the day bins located in a sorbent preparation building including transport blowers, coolers, and associated piping

- Sorbent mills for optimizing the particle size of the sorbent prior to injection into each boiler flue

- Sorbent injection equipment including filter receivers, airlock feeders, blowers, coolers, and piping up to the wall of the sorbent preparation building.

- All piping between the railcar unloading skid and the sorbent prep building.

- All piping inside the sorbent prep building.

- Sorbent injection lances

- Dedicated PLC's for the control of all equipment included in the proposal

- Engineering to facilitate the integration of the sorbent control system into the plant control system

- Computational Fluid Dynamics (CFD) of each flue to confirm predicted sorbent effectiveness

Additional BOP equipment, ancillary support systems, foundations that are required for the DSI system, but were not included in the BACT vendor proposal have been accounted for by Stanley Consultants in the cost estimate. This scope includes:

- Piping between the sorbent preparation building and the injection lance on each boiler's respective, outlet flue.

- Additional ductwork on Boiler 5 to increase sorbent resonance time prior to the baghouse

- Electrical feeds and equipment required to support the BACT vendor equipment (new feeds and equipment only, the suitability of the existing plant electrical system was not evaluated)

- Foundations

- Sorbent preparation building and interior structures

- Miscellaneous steel and supports

Equipment Layout

The cost estimate is based on the following approximate equipment locations:

- Unloading Equipment
    - North of Chena River
    - A rail spur adjacent and immediately northwest of the existing coal unloading building on the north side of Phillips Field Road
- Bulk Storage and Transfer Equipment
    - North of Chena River
    - Adjacent to the existing coal pile on the south side of Phillips Field Road.
- Sorbent Preparation Building
    - South of Chena River
    - Adjacent to the existing baghouse

See the sketch included as Appendix C for additional information on the proposed equipment locations and interconnecting piping.

General Assumptions

The estimated accuracy of this Opinion of Probable Costs is +50% and -15%. The approach used during the cost estimating effort was to make every reasonable assumption to simplify the project and reduce the estimated capital cost. Preliminary design activities, such as general arrangements and system integration evaluations were conducted to determine the essential project scope that would be required. Existing systems were assumed to have sufficient capacity to support the additional DSI equipment without modification. Existing foundations were utilized to estimate the cost of foundations for the new equipment, without consideration for recent code changes or review of recent geotechnical study results. Every effort was made to develop an estimate of the lowest realistic cost necessary to install DSI at the Chena Power Plant. This approach was utilized to reduce the downside uncertainty associated with the projected cost and to reinforce the conclusion that a DSI system is not a cost-effective emissions control alternative.

Given the approach outlined above, many potential design considerations that would typically add significant cost to any project were assumed not to be necessary. In general, if it was not apparent that a cost was essential to the completion of the project, it was omitted from the cost estimate. Design considerations that were intentionally undervalued or omitted from the estimate include, but are not limited to:

1. Hazmat abatement (asbestos, lead, PCB’s, soil remediation)
2. Subsurface Investigations (Geotechnical Report)
3. Existing soil conditions and impact on foundation requirements
4. Impacts of project on existing electrical system (capacity, redundancy, expansion requirements)
5. Structural capacity of existing buildings and steel structures
6. Seasonal work phasing / productivity
7. Expansion of plant utilities (air, cooling water, electrical, HVAC)

8. Rail spur engineering or construction. Existing spur was assumed available and appropriately configured for tank car staging, without primary rail operating disruptions.
9. Owner's costs, including owner's project management, owner's engineer, startup sorbent, spares, and permitting costs were excluded from this estimate.
10. Project costs related to taxes, duties, and tariffs.
11. Owners contingency

Stanley Consultants has provided cost estimates for several recent projects at various locations in the State of Alaska. Our experience to-date has been that the use of typical cost estimating resources (in this case, RS Means) will result in a cost estimate that is significantly below the costs that are actually incurred by the Owner. Installation costs used in this estimate were taken directly from RS Means. Rates were factored slightly upward to account for construction costs in interior Alaska.

All costs are expressed in January 2020 US dollars and a 14-month escalation prior to construction has been included.

Technical Methodology and Assumptions

The methodology utilized to develop project quantities along with the subsequent procurement and installation costs is detailed below. Several assumptions were made about the equipment requirements and BOP aspects concerning the installation of a dry sorbent injection system at the Chena Power Plant. The most significant assumptions, by discipline, are as follows.

General

Quantities of commodity products (piping and electrical cable) were based on distances scaled from Google Earth satellite imagery. Determined distances were then multiplied by an aggregate cost for material and labor obtained from RS Means Cost Estimation references. These costs include estimated commodity quantities along with any other components that are necessary for proper installation. The material and labor unit pricing for each of the components indicated were multiplied by a factor to obtain representative pricing in Fairbanks, Alaska. The summation of the aggregated costs, for each unit was divided by the measured distances to determine the unit costs presented. Factored RS Means data was also utilized to estimate equipment installation costs.

General craneage and forklift costs were also estimated based on RS Means costing data and multiplied by a factor to obtain representative pricing for the Fairbanks, AK location. Durations were estimated based on the anticipated project schedule. Cranage costs for pile driving operations were considered separately.

Civil / Structural

Stanley Consultants has assumed that all heavy structures or structures with a low tolerance for possible settlement will be founded on deep, pile foundations. This is based not only on the soil bearing capacities indicated by the rail unloading building foundation design drawings, but on the proximity of these structures to the river bank.

All light structures that can tolerate a minor amount of settlement were assumed to be founded on shallow, spread footings bearing on soils over-excavated and replaced with structural fill.

Unit costs for drilled caissons are based upon RS Means data for 24 inch diameter pipe piles driven in wet ground. Concrete fill will then be placed in the pipe above the soil plugs. Adjustments were made to the RS Means labor rates using blended wage rates for this project. It was assumed that a 150-ton crane with pile leads and pile hammer will be used. Civil excavation is assumed to proceed with heavy construction equipment.

Concrete is assumed to be batched at a batch plant with material costs based upon US rates. Concrete placement hours are based upon RS Means hours for manual placement adjusted by the productivity factor.

Structural steel was estimated by lineal feet for a pipe bridge, by square feet for platforms and by piece for the pipe supports.

Electrical

The existing master one-line diagram identified two 600A spare breakers on the 480V switchgear. It is assumed the existing electrical system has spare capacity to utilize these spare breakers. These spare breakers would each feed an outdoor motor control center (MCC) rated at 600A each. No modifications to the existing electrical infrastructure, no alternate power feeds, and no protective relay replacements were included in the electrical cost estimate. Note: modifications may be required but were not included herein.

It was assumed that conduit would be routed above grade using existing building columns or support steel. Cable tray may be used as space allows. Above grade routing of circuits is the most economical. New conduit support steel was not included in the cost estimate.

The only below grade electrical installation is for the bare copper ground grid and ground rods surrounding the new equipment and MCC locations and would connect to the existing ground grid in a few locations.

Mechanical

The facilities existing features have sufficient margin and correct configuration to be used to support the sorbent conveyance piping, which the vendor has indicated as 6" schedule 80 carbon steel pipe. Excessive ancillary steel for piping supports or to augment existing steel features has not been included in the cost estimate.

Piping and supports in the sorbent storage silos and sorbent preparation building were provided by the vendor in the pricing and was not estimated as part of the BOP cost estimate.

Instrumentation & Controls

The quote from the equipment vendor includes the majority of the instrumentation and controls scope. The cost estimate includes costs for miscellaneous materials and engineering services provided by the existing control system vendor to facilitate the integration of the DSI system controllers.

Equipment Performance, Sizing, and Pricing

Sorbent consumption numbers and equipment sizing were developed based on typical performance characteristics. These characteristics are typical of a flue gas system that operates at or near 500 °F and has sufficient duct length ahead of a baghouse to ensure at least 2 to 3 seconds of resonance time for the sorbent. The flue gas streams from the Chena boilers operate at significantly lower temperatures (300 to 350 °F). The potential reduction in sorbent performance due to the existing flue gas temperatures has not yet been evaluated. Adjustments to the maximum capture rate or sorbent feed rate may be determined to be necessary as the preliminary design develops. The quote obtained for the DSI system and equipment can be found in Appendix C.

Other equipment pricing is identified in the cost estimate in Appendix D. Equipment costs include an allowance for shipping, technical field supervision during erection and commissioning, and training.

Contractor Cost Assumptions

Project indirect costs include costs to manage, supervise, provide safety oversight/reporting, construction procurement, QA/QC, security, start-up and commissioning, housekeeping staff, and insurance requirements to support the project. These costs are listed at the bottom of the cost estimate summary sheet and are calculated as a percentage of the bare costs. The prime contractor indirect labor and labor burdens on prime contractor's labor can vary considerably from 10% to 60% of bare costs additional depending upon owner stipulated requirements and scope concerning the indirect costs listed.

Contractor profit was estimated at 10% for this cost estimate. In addition to the projects risk, profit also has a strong dependency on the owner's requirements concerning construction activities, competitiveness and other market conditions, and the availability of trades necessary to execute the work.

The cost estimate assumed that the prime contractor will self-perform all aspects of the work. Typically, prime contractors need to subcontract civil, electrical, and architectural work. Each of these subcontractors to the prime contractor have their own overhead and profit that is then marked up again by the prime contractor. No subcontract to the prime contractor mark-ups have been assumed in the cost estimate.

Owners Cost Assumptions

Project costs that are unrelated to the construction contract were also excluded from the cost estimate. These costs include administrative expenses, O&M mobilization and training, security surveillance, owner insurance during construction, and testing and commissioning. Proposed non-construction costs for the example projects were reviewed and converted to a value expressed as a percent of total construction cost. These values were then used as a guide for approximating non-construction costs for this project.

Opinion of Probable Cost

Based on the information above, the current minimum estimate of probable cost for a DSI system is as follows:

- Total Installed Cost: $20.6 MM
- Sorbent Cost: $550/Ton, Delivered

Sorbent pricing information provided by BACT in their proposal was supplied by a sorbent vendor based on data from the year 2000. Stanley Consultants is aware of sorbent pricing from other operators in the region, but we have not been given explicit permission to identify the price or the plant in question. The price identified above is our best estimate for current pricing based on the information that is available at the time of this report.

Appendix A

SCR Information

BACT PROCESS SYSTEMS, INC.

3345 N. ARLINGTON HEIGHTS RD. SUITE B
ARLINGTON HEIGHTS, IL 60004-1900
(847) 577-0950
FAX: (847) 577-6355
E-MAIL: bact_process@sbcglobal.net

November 15, 2018

Mr. John Solan, P.E.
Senior Mechanical Engineer
STANLEY CONSULTANTS
8000 S. Chester St., Suite 500
Centennial, CO 80112

RE: Aurora Energy NOx Control / BACT File No. 18113

Dear John,

Following our conversation of yesterday, I have talked to the technical personnel at Haldor Topsoe, a leading catalyst supplier.

Here are their comments for SCR:

A. Minimum temperature for Catalyst: 350°f.
B. 50% turndown is acceptable in the Reactor.
C. Catalyst will work at 800-850°f, they have a number of installations in coal fired boiler. However, they caution SO_2 level should be taken into account if the SCR is before economizer and dry injunction.

Regarding the SNCR, I am attaching two write-ups we prepared for incorporating SNCR into the coal fired boilers. I believe this may be useful to you in your investigation of this approach.

Please feel free to call me with any questions you may have.

Best regards,

BACT PROCESS SYSTEMS, INC.

N.S. ("Bala") Balakrishnan
President

From:	Dale T. Pfaff
To:	Solan, John
Cc:	Reid Thomas
Subject:	FW: Current Lower Operating Temp Limit for SCR Catalyst
Date:	Tuesday, December 4, 2018 4:29:29 PM

John:

I apologize for the delay in this response. In discussing this with FTEK's SCR Group, the usual minimum temperature for catalyst is ~400 °F for a reasonable catalyst volume. If the temperature falls much below that, one has to consider reheating the flue gas. It may become more economical to heat the flue gas back up as opposed to buying additional catalyst. However SCR reactions will still occur down to 350-365 °F. 365 °F has been quoted as a cutoff by one of our catalyst suppliers.

Please let me know if this answers your question.

Dale Pfaff
Fuel Tech
(847) 504-6650

Begin forwarded message:

From: "Solan, John" <SolanJohn@stanleygroup.com>
Date: November 28, 2018 at 9:46:26 AM CST
To: "Dale Pfaff (dpfaff@ftek.com)" <dpfaff@ftek.com>
Subject: Current Lower Operating Temp Limit for SCR Catalyst

Dale,
Can you answer a very quick question for me? What is the current lower operating temperature limit for commercially available SCR catalyst?
I need some documentation from a vendor for this BACT study that we are doing for Aurora Energy in Fairbanks.

Thanks in advance,
-John

John Solan, P.E.*, Senior Mechanical Engineer
STANLEYCONSULTANTS, 8000 S. Chester St., Suite 500, Centennial, CO 80112
T: 303.649.7830 | stanleyconsultants.com
* Registered in the States of North Carolina, Colorado, and Alaska

Appendix B

SNCR Information

BACT PROCESS SYSTEMS, INC.

3345 N. ARLINGTON HEIGHTS RD. SUITE E
ARLINGTON HEIGHTS, IL 60004-1900
(847) 577-0950
FAX: (847) 577-0355
E-MAIL: bact_process@sbcglobal.net

STEPS TO DESIGN SNCR IN EXISTING BOILER

(a) Visit the plant to inspect the boiler

(b) Review the following information:

   i. Boiler design drawings including grate and overfire air system arrangement
   ii. Coal analyses (all possible sources)
   iii. Performance predictions

(c) Estimate furnace exit gas temperature (FEGT) based on standard manufacturer's design curves.

(d) (Optional) Use computer modeling to determine the following furnace gas conditions:

   i. Temperature profiles:

      1. Along the length of the super heater inlet tubes
      2. In the cavity between the super heater and boiler bank

   ii. Gas flow profiles
   iii .Estimates of O2, CO and NO concentrations
   iv. Potential for changing furnace combustion conditions (over fire air flow and distribution, flue gas recirculation, etc) to reduce NO formation

(e) Design the Urea injection system including:

   i. Quantity of urea to be injection to meet expected control requirements including sufficient excess capacity
   ii. Number of spray nozzles
   iii. Location of spray nozzles
   iv. Nozzle size, arrangement (using Caldyn nozzles) and spray pattern

v. Expected performance at full and ¾ load

(f) Integrate the injection system design with the design of the urea delivery, storage and handling system

REVIEW AMMONIA INJUNCTION SYSTEM:

i. Quantity of ammonia to be injection in the cavity between the superheater and boiler bank to meet the expected control requirements and with sufficient excess capacity

ii. Number of spray nozzles
iii. Location of spray nozzles
iv. Nozzle size, arrangement (using Caldyn nozzles) and spray pattern
v. Expected performance at full and ¾ load
vi. Safety issues

i. Evaluate potential NO reduction techniques:

i. Review the modeling results (see (e)(iv) above
ii. Identify potential fuel and air system hardware changes (in any) and design, specify, fabricate components as appropriate
iii. Identify operational changes (if any) and incorporate into the testing as appropriate

j. Determine additional instrumentation and control system requirements
i. Furnace gas temperature measurements
ii. Ammonia slip monitors
iii. Other

2. Prior to Boiler Restart-up

a. Install urea handling and injection system

b. Install furnace wall penetrations for temperature profile measurements and subsequent urea injection trials

c. Install boiler wall penetrations for cavity temperature profile measurements and subsequent ammonia injection trials (if needed)

d. Install other boiler penetrations for temperature and gaseous measurements as needed

e. Install hardware changes from (1)(i) as appropriate

f. Install additional instrumentation (see(1)(j) above)

g. Conduct "cold boiler" testing
   i. Coal distribution onto the grate
   ii. Adjust fuel distributor settings as appropriate
   iii. Overfire airflow distribution and penetration

3. Engineering Activities during "10-Day" Testing Period

   a. Observe boiler operations following achieving steady and sustained boiler operations at or near full load

   b. Boiler gas temperature profile measurements
      i. Furnace exit along length of superheaters
      ii. Superheater outlet
      iii. Boiler bank outlet
      iv. Economizer outlet
      v. Airheater Outlet
      vi. Scrubber/ID fan outlet

   c. Determine the sensitivity of FEGT measurements with changes in boiler operations
      i. Using the "as-found" boiler firing configuration
      ii. Following operational adjustments(load, excess air, air and fuel distribution (refer to (2)(g) above), etac.)
      iii. Using the hardware changes identified in (2)(e) above
      iv. Determine the effects on furnace NO levels

   d. Establish the firing conditions that product the "best" FEGT profile with minimum NO formation for use with urea injection.

   e. Establish the firing conditions that produce the "best" temperature profile in the cavity with minimum NO formation for use with ammonia injection

   f. Conduct initial urea injection trials using (d) above
      i. Vary the urea Normalized Stoichiomeatric Ratio (NSR)
      ii. Vary the urea spray pattern between the injection nozzle matrix

iii. Evaluate differing nozzle sizes and arrangements
iv. Determine:
1. Impacts on NO reduction
2. Impacts on ammonia slip
3. Effects on FEGT variations

g. Repeat (f) above with a second firing arrangement that achieves a different FEGT profile

h. Repeat (f) above with a third firing arrangement that achieves a different FEGT profile

i. Analyze and report the results of trials

4. If Emission Levels ARE Acceptable

a. Select the best arrangement for urea SNCR from the tests conducted in (3)

b. Operate the system over long-term (30 to 60 days)

c. Prepare recommended operating guidelines

d. Conduct boiler operating training session(s)

e. Assist (as needed) with compliance tests

f. Assist(as needed) with long term urea injection system operations and emission controls

5. If Emission Levels ARE NOT Acceptable:

a. Conduct initial ammonia injection trials using (3)(e) above
i. Vary the ammonia Normalized Stoichiometric ratio (NSR)
ii. Vary the ammonia spray pattern between the injection nozzle matrix
iii. Evaluate differing nozzle sizes and arrangements

iv. Determine:
1. Impacts on NO reduction
2. Impacts on ammonia slip
3. Effects of cavity temperature variations

b. Analyze and report results of trials

6. If Emission Levels ARE Acceptable, see (3) above

7. If Emission Levels ARE NOT Acceptable:

   a. Determine the firing arrangement that produces the optional FEGT and cavity temperature for combined urea/ammonia SNCR operations from (3)(d)+(e) above

   b. Conduct initial urea/ammonia injection trials using (a) above
      i. Vary the ammonia Normalized Stoichiometric Ratio (NSR)
      ii. Vary the ammonia spray pattern between the injection nozzle matrix
      iii. Evaluate differing nozzle sizes and arrangements
      iv. Determine:
         1. Impacts on NO reduction
         2. Impacts on ammonia slip
         3. Effects of cavity temperature variations

   c. Analyze and report results of trials

8. If Emission Levels ARE Acceptable, see (4) above

BACT PROCESS SYSTEMS, INC.

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SNCR FACTS

REAGENT:	UREA OR AMMONIA
NOx REDUCTION	30% - 50%
TEMPERATURE:	NH3 = 1600 oF – 2000 oF
	UREA = 1650 oF – 2100 oF
RESIDENCE TIME:	.5 SECONDS
AMMONIA SLIP:	5-10 PPM
STORAGE UREA CONCENTRATION:	50% - 70%

Appendix C

DSI Information

BACT PROCESS SYSTEMS, INC.

3345 N. ARLINGTON HEIGHTS RD. SUITE B
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November 1, 2018

Mr. John Solan, P.E.
Senior Mechanical Engineer
Stanley Consultants
8000 S. Chester Street, Suite 500
Centennial, CO 80112

RE: DSI for Aurora Energy / BACT Proposal No. 1899-R1

Dear John,

We are revising our proposal in the light of your comments. The Emissions and sorbent usage from the boiler is based on recent information from you: on 0.39 lbs. of SO2/MBTU these calculations are based on using a weight ratio of 2.6 lbs. of sodium bicarbonate to 1 lb. of sulfur and a NSR of 1.3; Sulphur at .28%; Heating Volume of 7,600; 80% removal of SO2.

BOILER	MBTU/HR	S02 PPH	SODIUM BICARBONATE PPH
1	76	29.64	100
2	76	29.64	100
3	76	29.64	100
4	269	139.88	400
		TOTAL 228 PPH	700 PPH
			0.35 Tons/Hr.
	Per Month:	8.4 Tons/Day	252 Tons

Bicarbonate Storage

For four months; we need 756 Tons of sorbent
(2) Silos: 518 Tons capacity each
TOTAL CAPACITY = 1,036 Tons
Silo Size: Same as Eielsen

Cost of Sodium Bicarbonate = $123,480 per month; this is based on estimate by Solvay for year 2000 delivery: $250 plus, $240 freight.

Scope of Supply

1. (2) Bolted Storage Silos – 22' DIA x 100' tall with bin-vent level control and bin vibrators; capacity = 1,036 tons; storage silo complete.
2. (1) Rail car unloading and diverters to fill silos located 500' away; rate = 33,000 PPH, blower = 200 HP; installed spare; backup blower.
3. (3) Day bins with pneumatic conveying from storage silos. Conveying distance 1,000', 6,000 PPH capacity, blower = 200 HP; blowers are spared.
4. (3) Classifier mills; 1,000 PPH capacity, 75 HP total, connected HP (for 2). The 75 HP is the sum of the grinding motor, classifier motor, brakes, and VFD.

5.&6. (3) Filter receivers with conveying blowers. Milled material conveying material from mill to filter receivers. (2) Blowers 75 HP total; total connected.

7. (4) Injector sets to be installed on duct work.
8. (1) Dedicated compressor.
9. (1) NEMA 6 control panel with microprocessor.
10. Integration to the boiler control panel.
11. CFD modeling and programing.
12. All pneumatic piping up to the reagent building. All piping within the sorbent prep building by BACT. Pipe from the building wall for the 4 pipes leading to each stack by customer. Air coolers are provided to minimize puffing of the reagent.
13. Sorbent building and foundation by customer.

Budget Sell Price: $4,900,000
Freight: $ 200,000
F.O.B. Shipping Point
Taxes Extra

If you have any questions, please let me know.

Best regards,

BACT PROCESS SYSTEMS, INC.

N.S. ("Bala") Balakrishnan
President

Aurora Energy LLC
Chena CHP Plant
N
Sorbent Railcar Unloading Skid
Pipe & Power thru Utilidor (under road).
Sorbent Storage Silos
Unit 5 Injection
Sorbent Prep Enclosure
Unit 1 Injection
Unit 2 Injection
Unit 3 Injection
Google Earth
© 2018 Google
300 ft

Google Maps Fairbanks

Imagery ©2018 Google, Map data ©2018 Google 50 ft

49.88 ft

Google Maps Fairbanks

Appendix D

DSI Opinion of Probable Cost

Stanley Consultants INC.		Rev. 1	Job No.	28709.01.00	Page No.	1
			Subject	Aurora Energy Chena - Dry Sorbent Injection		
Computed by	J. Smith / S. Worcester/ D. Bacon	Date 2/8/2019		Opinion of Probable Cost		
Checked by	J. Solan	Date 2/8/2019				
Approved by	C. Spooner	Date 2/8/2019	Sheet No.	1	of	1

Item Description		Quantity		Unit Cost	Total Cost
		No. of Unit	UOM		
Engineering Services					
Engineering services provided throughout the project to assist with BOP design, technical specifications, procurement, bid evaluation, and construction observation.		1	EA	$1,873,100.00	$1,873,100
Dry Sorbent Injection System Supply					
DSI	Includes Railcar offloading, long term storage silos, day storage silos, milling, metering and feed.	1	EA	$4,900,000.00	$4,900,000
DSI Installation	Field Installation	1	EA	$1,550,000.00	$1,550,000
DSI Equipment Freight	FOB jobsite	1	EA	$200,000.00	$200,000
Structural					
Silo Foundation		2	EA	$244,304.00	$488,608
Sorbent Building Substructure		1	EA	$247,047.00	$247,047
Sorbent Building Superstructure		1	EA	$183,067.00	$183,067
Sorbent Building Exterior Closure		1	EA	$160,334.00	$160,334
Roofing		1	EA	$12,149.00	$12,149
Railcar Unloading Skid Foundation		5	CY	$650.00	$3,250
Transfer Skid Enclosure Foundation		5	CY	$650.00	$3,250
MCC Foundation		4	CY	$650.00	$2,600
Pipe Bridge by Silos - Steel	coal yard front end loader drive under.	4	TONS	$9,000.00	$36,000
Pipe Bridge by Silos - Foundations		6	CY	$650.00	$3,900
Outside Pipe Supports - Steel		10.0	TONS	$9,000.00	$90,000
Outside Pipe Supports - Foundations		40	CY	$650.00	$26,000
Inside Pipe Supports - Steel		3.00	TONS	$9,000.00	$27,000
Ductwork	100' Feet of Ductwork for Residence Time prior to PJFF	12.50	TONS	$10,300.00	$128,750
Mechanical					
Unit 1 Aggregate Piping Cost: 6" Sch 80 Pipe/Fittings/Flanges/Supports - Sorbent Prep to Injection Location		300	LF	$300.00	$90,000
Unit 2 Aggregate Piping Cost: 6" Sch 80 Pipe/Fittings/Flanges/Supports - Sorbent Prep to Injection Location		310	LF	$300.00	$93,000
Unit 3 Aggregate Piping Cost: 6" Sch 80 Pipe/Fittings/Flanges/Supports - Sorbent Prep to Injection Location		280	LF	$300.00	$84,000
Unit 5 Aggregate Piping Cost: 6" Sch 80 Pipe/Flanges/Supports - Sorbent Prep to Injection Location		200	LF	$300.00	$60,000
Electrical					
480V MCC	Mtl & Labor	2	EA	$65,177.00	$130,354
480V Panelboard and Xfmr	Mtl & Labor	2	EA	$10,200.00	$20,400
Cable - 480V - MCC, Loads	Mtl & Labor	9000	LF	$14.83	$133,436
Conduit - RGS	Mtl & Labor	6800	LF	$20.26	$137,748
Cable Terminations (Mat'l)	480V Material & Labor	496	EA	$26.11	$12,950
Light Fixtures Interior/Exterior	Surface mounted LED light fixtures (Mtl & Labor)	20	EA	$1,561.00	$31,220
Ground Grid extension	Mtl & Labor	1050	LF	$13.43	$14,100
Instrumentation & Controls					
BOP DCS Aspects		1	EA	$76,428.00	$76,428
All Terrain Forklift	45' lift, 35' reach, 9000 lb. capacity	12	WK	$6,455.00	$77,460
Hydraulic Crane	80-ton	90	DY	$4,365.00	$392,850
				Furnish and Erection Subtotal	$9,415,901
	MOBILIZATION / DEMOBILIZATION & MISC COSTS			8%	$753,272
	PRIME CONTRACTOR INDIRECT LABOR			40%	$1,538,236
	CONTRACTOR OH & LABOR BURDENS ON PRIME CONTRACTORS LABOR			15%	$1,412,385
	EQUIPMENT & SMALL TOOLS			10%	$902,305
	CONTINGENCY			15%	$2,103,315
	PROFIT			10%	$1,402,210
	BOND			2%	$350,552
				Total Construction Cost	$17,878,177
	Escalation Percent 4.00%	Periods 14		Escalation (Nov 2018 - January 2020)	$852,635
				PROBABLE EQUIPMENT & CONSTRUCTION COST	$18,731,000
				PROBABLE ENGINEERING, EQUIPMENT & CONSTRUCTION COST	**$20,604,000**

Note: All costs presented in this document are Stanley Consultants' opinions of probable project, construction, and/or operation and maintenance costs. This estimate of probable construction cost is based on our experience and represent our best judgment. We have no control over cost of labor, materials, equipment, contractor's methods, or over competitive bidding or market conditions. Therefore, we do not guarantee that proposals, bids, or actual construction costs will not vary from estimates of project costs, construction, and/or operation and maintenance costs presented. The costs identified are based on Means Building Construction Cost Data, Engineering News Record Construction Cost Index, and/or vendor quotes.